Australian Government

Department of Industry, Innovation and Science

Regulation Impact Statement

Standard form

Australian Domestic Gas Security Mechanism

June 2017

Disclaimer:

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1 Executive Summary

Over the past decade Australia's liquefied natural gas (LNG) capacity has grown substantially on the back of $200 billon investment in gas facilities in Western Australia, Northern Territory and Queensland. By 2021, Australia is set to equal or exceed the production capacity of Qatar, currently the world's largest LNG producer. Part of this capital investment has been in developing Australia's significant onshore gas resources, particularly coal seam gas resources in Queensland. While gas reserves are currently substantial and gas production has increased, gas supply on the east coast is struggling to keep pace with demand. Recent forecasts by the Australian Energy Market Operator (AEMO) predict a tight supply/demand balance and potential domestic shortfalls in coming years. It has become evident that, in part, the reason for tight supply is because some export projects are drawing a larger than expected volume from the domestic market.

This situation is placing some gas-using sectors at high risk of shutting down. The Government estimates that as many as 65 000 jobs rely on industries where gas often makes up more than 15 per cent of input costs. Security of supply and higher prices have also impacted on industry competiveness and household cost of living. The uncertainty of supply security and failures in the gas market require Government action.

The Government is intervening to respond to market shortfalls in a number of ways, including: committing $28.7 million for measures to increase the supply of gas; obtaining a guarantee from gas producers to ensure that gas is available for the national electricity market during peak periods; and launching an Australian Competition and Consumer Commission (ACCC) investigation into Australian gas markets and work to improve market transparency. However, these initiatives are expected to have an impact in the medium term.

Therefore, to have a more timely and targeted impact on gas security, the Government decided to introduce an export licensing system, referred to as the Australian Domestic Gas Security Mechanism (ADGSM) by 1 July 2017. This decision was made following consideration of an interim Regulatory Impact Statement (RIS). The Department of Industry, Innovation and Science (DIIS) has lead policy responsibility for the implementation of the ADGSM.

This RIS considers three policy options for Government intervention in addition to the status quo: an industry led agreement, gas reservation policy and export controls. Each option was considered on its merits, as detailed in Section 5. The ADGSM was evaluated as being the most favourable in terms of balancing outcomes for domestic gas users and potential impacts on gas exporters.

The ADGSM will be a regulation under the *Customs Act 1901*, with guidelines to contain detailed process and timeframes for how the mechanism will operate. Risks will be managed on an ongoing basis through finalisation of the design in consultation with industry and international trading partners. Feedback from consultations and submissions resulted in a number of improvements to the mechanism. Consultations on the exposure draft legislation and guidelines also occurred.

The ADGSM is a temporary measure and will be repealed on 1 January 2023, if it has not already been repealed by this date. After the first two years of operation, a review of the mechanism will take place to assess whether it has operated as intended and whether it has had a material impact on energy security and sectors of the economy that rely on gas.

2 Policy Problem

In the absence of government intervention Australia's east coast gas market faces the prospect of future gas shortfalls, or insufficient gas supply, to meet projected demand.

In March 2017, the Australian Energy Market Operator's (AEMO's) Gas Statement of Opportunities (GSOO) forecast stated that unless supply increases, gas supply shortfalls will emerge in some states from 2018-2019 of between 10 petajoules per annum (PJ/a) and 54 PJ/a to the end of the 2036 outlook period. AEMO forecast domestic demand to remain flat over the outlook, with increases in population growth and gas powered electricity generation being offset by the movement of the economy away from energy-intensive industry, improvements in energy efficiency and changing consumer preferences for electrical appliances. With negligible changes in domestic demand growth on the east coast, the immediate drivers of the shortfall in the domestic market are a reduction in gas production, from 600 PJ in 2017 to 478 PJ in 2021 that is occurring while liquefied natural gas (LNG) production for export increases to 1,430 PJ/a by 2020.[1]

Even if a shortfall is not predicted in subsequent updates to the GSOO, the supply-demand balance in the east coast market is expected to be tight and be heavily influenced by the behaviours of LNG exporters.

The drivers of shortfall

A range of major gas consumers on the east coast are reportedly receiving contract offers well above export parity prices even allowing for transport and distribution costs. The following indicate technical, regulatory and market factors are generating uncertainty about future gas supply, and will contribute to shortfalls in the east coast domestic market:

- Net gas flows to the LNG projects, which are removing gas from the domestic market.
- Low oil prices, which are resulting in declining investment in gas exploration and drilling resulting in lower production forecasts for both domestic and LNG projects.
- Moratoria and regulatory restrictions which are affecting onshore gas exploration and development, particularly in New South Wales, Victoria and the Northern Territory.
- Higher than expected costs of gas production associated with developing coal seam gas (CSG)
- Lack of market transparency, including price information.
- Poor gas production flow rates in some new unconventional gas resources, which compromise the financial viability of field development.
- Declining production of mature petroleum basins.

In their 2017 State of the Energy Market Report, the Australian Energy Regulator noted most gas sales in eastern Australia are struck under confidential bilateral contracts, traditionally locking in terms and conditions over a long period. While the industry has shifted towards shorter term contracts with review provisions more recently, public information about wholesale gas prices is opaque.

Most pricing information is private and particular to specific contracts and negotiations. There is also disparity between the type of information available to large participants such as gas producers and retailers, and what is available to customers that less frequently participate in the market. Currently,

[1] Australian Energy Market Operator, March 2017, *Gas Statement of Opportunities for Eastern and South Eastern Australia*

no accurate and useful indicative price is readily available to the market. Nevertheless, it is clear that gas prices struck under new contracts have risen sharply, with offerings up to $20 per gigajoule being quoted in 2017. These prices are significantly above LNG netback prices (allowing for transport and distribution/retail costs), making it theoretically more profitable for an LNG producer to sell gas domestically than to export it[2].

The challenges in supply gas to markets

The Australian Government monitors and analyses the impact of LNG export facilities on the east coast market. In 2014, the Government released the Eastern Australian Domestic Gas Market Study (the Gas Market Study) to help address information gaps and inform debate on strategy for gas policy. More recent reform processes include the ACCC's 2016 inquiry into the east coast gas market, which looked into the competitiveness of wholesale gas prices as well as the structure of the gas industry, and the Australian Energy Market Commission's (AEMC) 2016 East Coast Wholesale Gas Market and Pipelines Frameworks Review. The ACCC inquiry and AEMC review recommended ways to promote gas market competition and encourage supply. The recommendations included reforms to spot market design, better quality information to market participants, and easier access to gas pipelines. In August 2016, the Council of Australian Governments (CoAG) Energy Council agreed to establish the Gas Market Reform Group to implement the Inquiry's and Review's recommendations.

Recognising the impact of a supply constrained east coast market, both the Gas Market Study and the ACCC inquiry recommended against any form of reservation style restrictions, or export controls, instead recommending reforms to improve the operation of the gas market to drive incentives for investment in new supply over the long term.

While these reforms are ongoing, the supply situation, and consequential impact on gas contract prices, have worsened faster and more deeply than anticipated. This can be partly attributed to technical issues experienced by the upstream CSG field operations of the three LNG projects in Queensland. The Queensland LNG projects are the first globally to produce LNG using CSG as the predominant feedstock. While this has been largely successful, there have been challenges for gas companies. Gas produced from coal seams, when compared to conventional geological reservoirs, has different production characteristics. Moreover, modelling of conventional field production has been developed over decades and will yield a reasonably high level of accuracy while model flow rate volumes and overall production returns for CSG fields remains challenging. Wells drilled are returning variable results and, notably, lower than expected production volumes. This issue has been exacerbated by the low oil price which has led to more conservative investment decisions away from new field development and research to overcome technical issues.

As a consequence, at least one project is reported to have a deficit in the amount of gas required to meet their LNG commitments, meaning that gas needs to be purchased from other fields, some of which have historically supplied the domestic market. This lower than anticipated production of CSG has meant the anticipated extra surplus of gas initially predicted to be available to the domestic market has not eventuated.

LNG exporters have sales commitments with buyers that are typically secured through long-term contracts with inflexible or difficult-to-alter conditions. Some companies use 'own gas' and/or third

[2] Australian Energy Regulator, May 2017, State of the Energy Market

party contracted gas to meet these commitments. AEMO expects, under tight supply conditions, that LNG export demand will be satisfied first, and that any gas shortfalls would therefore impact supply to domestic consumers – industrial, commercial, residential customers, and gas powered generation[3]. Export schedules are also fixed into tight shipping schedules with buyers, typically over 18 month periods. These contract features can limit opportunities for LNG exporters to divert gas to the domestic market during periods of tight supply or to take advantage of higher domestic prices.

Impacts of not having sufficient gas

Supply security and price of gas are key risks for Australian industry competitiveness, and cost of living pressures. Half of all Australian households use mains gas, including 63 per cent of households in capital cities. The Government estimates that as many as 65 000 jobs rely on industries where gas often makes up more than 15 per cent of input costs (see Appendix A). In some of these industries, gas can account for up to 80 per cent of input costs, and in many cases there is limited or no ability to substitute for gas[4]. In 2014, BIS Shrapnel estimated that a shortfall would cost the east coast manufacturing sector a minimum of $14 billion[5]. Repercussions would also filter through to the broader economy, and include negative impacts on economic activity (gross domestic product) and overall employment[3]. For gas dependent industries to make investment decisions that are vital to their long run strategic positioning, they require more supply certainty.

To help find a solution to the potential crisis, the Prime Minister met with east coast exporters in March and April 2017. Throughout the industry meetings, the Government made it clear that its preference was for industry to respond of its own volition, and improve supply and price outcomes. Despite making progress, not all of the east coast LNG exporters satisfactorily outlined their plans to contribute more gas to the domestic market. See Section 6 for a comprehensive summary of subsequent stakeholder consultations.

The Government is committed to increasing the reliability and affordability of gas for Australian consumers and has announced a range of actions to increase the supply of gas in the medium term. In the short term, the Government has committed to improving energy security by intervening in the LNG export market to ensure domestic gas needs are met. To meet this commitment, the Government has announced the Australian Domestic Gas Security Mechanism (ADGSM). At present there is no regulation of LNG exports on the eastern seaboard. Without a mechanism to intervene in the market, the Government has limited power to prevent a domestic gas shortfall caused by LNG exports.[6]

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[3] AEMO. Gas Supply Statement of Opportunities. March 2017.
[4] Gas, being a utility, has several public good characteristics. For many uses including significant components of the manufacturing sector, gas is not excludable and not substitutable for other inputs, meaning it is indispensable. Further, when gas is substitutable, there are often high transactional costs in the form of duplicated infrastructure and any time delays in constructing this. However unlike fully public goods, gas is a natural resource which does not have indefinite supply. These characteristics are at the heart of the importance of securing a reliable supply, especially considering that Australia is one of the world's highest producers.
[5] BIS Shrapnel, September 2014, *The Economic Impact of LNG Exports on Manufacturing and The Economy*
[6] The Prime Minister, the Hon Malcolm Turnbull, 27 April 2017, media release.

3 Government Intervention

The reasons for current east coast gas market conditions are complex. While they cannot be solely associated with the commencement of LNG exports, it is clear that rising export demand and the failure of supply to increase incrementally are important factors in the gas security outlook.

The Government strongly supports the ongoing operation of Australia's world class LNG industry. The foundation LNG projects in Western Australia and Northern Australia have been the backbone for supplying their domestic gas markets.

Similarly, the East Coast LNG industry has underpinned the development of vast new CSG reserves in Queensland and the refurbishment of conventional tenements in the Cooper Basin. At the time the east coast LNG facilities were approved for operation, it was expected that they would largely meet their gas supply needs through the development of their own new resources as well as add additional supplies to the east coast market.

While this has largely been the case, the performance of some projects in developing their own supplies has been poorer than expected. It is now clear that the additional demand placed on the market, the inability of some exporters to adequately increase supply, and restrictions placed on developing new gas supplies in some jurisdictions, has driven prices well above the cost of production and transport, and generated the prospect of a market shortfall in future years.

In effect, much of the risk of under-performance in these export projects has been transferred onto domestic gas consumers. The prospect of gas shortages driving widespread industrial demand destruction, and spiralling household energy costs is not sustainable for domestic gas consumers or the economy.

It is important to note that if overall supply is sufficient to meet the needs of domestic gas consumers, the Government will not intervene in the market. Similarly, the Government has been clear that any intervention in the market would be targeted and temporary (see Section 8).

The rationale for introducing export controls is to:

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

A mechanism that discourages LNG exporters from excessively drawing from the domestic market would act as a powerful incentive for industry to develop new gas resources. Such a mechanism would also prevent an export-driven shortfall, thereby providing a 'back-stop' guarantee of domestic supply. However, the Government does not believe that export controls is the only solution to all of the issues with Australia's domestic gas markets. Export controls would complement other government, including CoAG Energy Council actions, which are designed to improve the efficiency, competitiveness and transparency of gas markets and increase the development of Australia's gas resources.

4 Policy Options

The Government has identified the following options to increase the reliability and affordability of domestic supply by influencing LNG exporters:

- Option 1: Status quo
- Option 2: Industry led agreement to guarantee adequate supply

- Option 3: Gas reservation policy
- Option 4: Export controls

4.1 Status quo – no change to the current unregulated environment

The status quo option represents what would occur in the absence of any specific action by the Government to address the policy problem outlined in Section 2. In other words, the Government would not intervene to ensure that there is adequate supply to the domestic market in the short term.

If there is no intervention, the Government will have no recourse to influence LNG exporters.

4.2 Industry led agreement to guarantee adequate supply

In this option, LNG exporters would nominate a specific volume of gas to guarantee an adequate supply of gas to the domestic market. This guarantee would likely come in the form of a formal, signed agreement between exporters and Government. Any terms of the agreement would be enforced by industry participants.

It is unclear how this option could be enforced to an extent that the domestic gas market would have confidence that supply is assured. During the consultation process this option was explored. However, industry were unable to provide a level of assurance sufficient to render this option viable in light of the risks of a domestic shortfall occurring if industry do not meet their stated supply commitments. The possibility of an industry-led solution would be appropriate to include in the option to be implemented.

4.3 Gas reservation policy – imposing a blanket quota for the domestic market

A gas reservation policy would reserve a fixed amount of gas production for domestic use or earmark specific acreage releases for gas exploration and development as only being for domestic sales. For example, Western Australia has a policy that reserves 15 per cent of gas from offshore developments while Queensland is providing some limited gas tenements as being for the domestic market alone.

Reservation policies, while not widely used in Australia to date, have been targeted at providing additional gas for the domestic market but without setting an overall target or cap for the amount delivered. It is not clear how a reservation policy would act as a mechanism to address a specific market shortfall at a point in time although it might be possible to establish a provision to have the gas reservation amount (eg the 15 % contribution rate) swing up or down according to circumstance

This raises several key issues:

- If the percentage was fixed, then to guarantee that there was no shortfall, the percentage would need to have a built-in margin of error to account for ‘normal’ fluctuations in production (such as unforeseen technical and maintenance events). This would result in the domestic market being oversupplied, to the extent that the trigger under-estimates the supply fluctuations, with the cost borne by exporters and a reduced incentive for other gas project developers to bring on new gas.
- If the percentage was fixed, but there was not a built-in margin of error, then the domestic market would be at risk of a shortfall. This would fail to achieve the policy objective of securing an adequate supply of gas for the domestic market.

A more serious limitation is that the Australian Government’s ability to impose a reservation policy (either in tenement earmarking or a domestic gas contribution amount) would be confined to gas resources in offshore waters. In the East Coast market this would be the offshore fields in Bass Strait and the Gippsland region. Under the Australian federation the States and Territories retain the responsibility for administration and management of on-shore gas resources. Applying a gas reservation policy gas in offshore waters would have limited or no effect on the East Coast market given that most of this gas currently supplies the Victorian and New South Wales markets.

The application of comprehensive reservation policy would therefore need to be implemented through cooperative action taken by the Australian and State and Territory Governments. Such action would take some time to develop in a uniform way and it is not clear that it would be supported by all governments.

Unless otherwise stated, when this RIS uses the term ‘gas reservation’ it refers to a blanket reservation policy that reserves a fixed percentage of gas, all the time through a policy framework agreed by the Australian and State and Territory Governments.

4.4 Export controls

Export controls would work by requiring LNG projects to obtain an Export Permission before exporting LNG. Permissions could have conditions attached to them, including the volume of LNG allowed for export. Similarly, before granting an Export Permission, the Government could consider an individual exporter’s contributions to market conditions like supply-demand balance and competition.

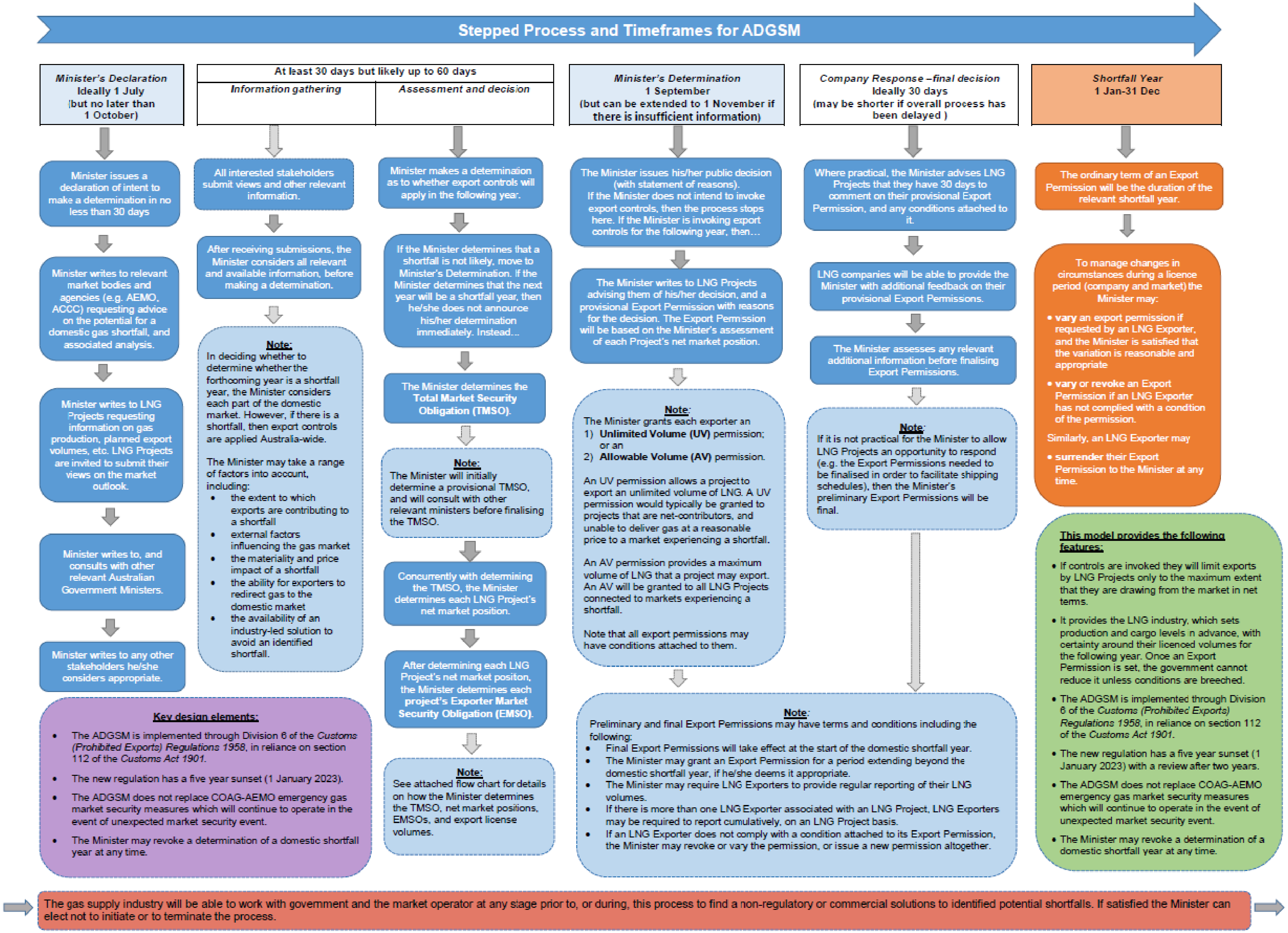
Like a blanket reservation policy, export controls have the potential to be triggered by a Government determination (e.g. of an impending shortfall of domestic supply). However, export controls are a “lighter touch” regulatory option, because they can be more easily targeted (e.g. at export projects that contributed to a shortfall). Similarly, they can be tailored so that exporters would only bear an additional cost if the market was not adequately supplied. This is consistent with the Government’s policy to encourage LNG export operations in Australia,.

There are a number of methods to implement export controls, as outlined in Section 8. Herein, unless otherwise stated, specific details of export controls relate to the Australian Domestic Gas Security Mechanism (ADGSM), which the Government announced on 27 April 2017. The ADGSM is considered the most effective method to implement export controls as it:

- effectively provides security for domestic gas consumers
- does not interfere in the market unless it is necessary to secure an adequate supply of gas for domestic gas consumers
- incentivises exporters to produce more gas rather than draw it from the domestic market
- minimised compliance costs and market distortions
- maximises the consistency and transparency of LNG exporters’ requirements, and flexibility in how the requirements could be met
- complements other Government initiatives including the ACCC gas market transparency monitoring regime, and the peak supply guarantee.

There is a discussion of alternative implementation methods in Section 8.

The following flow chart summarises how the ADGSM would operate and the steps were used to assess the regulatory costs in Section 5.



Stepped Process and Timeframes for ADGSM
Minister's Declaration
Ideally 1 July
(but no later than 1 October)
At least 30 days but likely up to 60 days
Information gathering
Assessment and decision
Minister's Determination
1 September
(but can be extended to 1 November if there is insufficient information)
Company Response – final decision
Ideally 30 days
(may be shorter if overall process has been delayed)
Shortfall Year
1 Jan-31 Dec
Minister issues a declaration of intent to make a determination in no less than 30 days
Minister writes to relevant market bodies and agencies (e.g. AEMO, ACCC) requesting advice on the potential for a domestic gas shortfall, and associated analysis.
Minister writes to LNG Projects requesting information on gas production, planned export volumes, etc. LNG Projects are invited to submit their views on the market outlook.
Minister writes to, and consults with other relevant Australian Government Ministers.
Minister writes to any other stakeholders he/she considers appropriate.
All interested stakeholders submit views and other relevant information.
After receiving submissions, the Minister considers all relevant and available information, before making a determination.
Note:
In deciding whether to determine whether the forthcoming year is a shortfall year, the Minister considers each part of the domestic market. However, if there is a shortfall, then export controls are applied Australia-wide.
The Minister may take a range of factors into account, including:
• the extent to which exports are contributing to a shortfall
• external factors influencing the gas market
• the materiality and price impact of a shortfall
• the ability for exporters to redirect gas to the domestic market
• the availability of an industry-led solution to avoid an identified shortfall.
Minister makes a determination as to whether export controls will apply in the following year.
If the Minister determines that a shortfall is not likely, move to Minister's Determination. If the Minister determines that the next year will be a shortfall year, then he/she does not announce his/her determination immediately. Instead…
The Minister determines the Total Market Security Obligation (TMSO).
Note:
The Minister will initially determine a provisional TMSO, and will consult with other relevant ministers before finalising the TMSO.
Concurrently with determining the TMSO, the Minister determines each LNG Project's net market position.
After determining each LNG Project's net market positon, the Minister determines each project's Exporter Market Security Obligation (EMSO).
Note:
See attached flow chart for details on how the Minister determines the TMSO, net market positions, EMSOs, and export license volumes.
The Minister issues his/her public decision (with statement of reasons). If the Minister does not intend to invoke export controls, then the process stops here. If the Minister is invoking export controls for the following year, then…
The Minister writes to LNG Projects advising them of his/her decision, and a provisional Export Permission with reasons for the decision. The Export Permission will be based on the Minister's assessment of each Project's net market position.
Note:
The Minister grants each exporter an
1) Unlimited Volume (UV) permission; or an
2) Allowable Volume (AV) permission.
An UV permission allows a project to export an unlimited volume of LNG. A UV permission would typically be granted to projects that are net-contributors, and unable to deliver gas at a reasonable price to a market experiencing a shortfall.
An AV permission provides a maximum volume of LNG that a project may export. An AV will be granted to all LNG Projects connected to markets experiencing a shortfall.
Note that all export permissions may have conditions attached to them.
Where practical, the Minister advises LNG Projects that they have 30 days to comment on their provisional Export Permission, and any conditions attached to it.
LNG companies will be able to provide the Minister with additional feedback on their provisional Export Permissions.
The Minister assesses any relevant additional information before finalising Export Permissions.
Note:
If it is not practical for the Minister to allow LNG Projects an opportunity to respond (e.g. the Export Permissions needed to be finalised in order to facilitate shipping schedules), then the Minister's preliminary Export Permissions will be final.
Note:
Preliminary and final Export Permissions may have terms and conditions including the following:
• Final Export Permissions will take effect at the start of the domestic shortfall year.
• The Minister may grant an Export Permission for a period extending beyond the domestic shortfall year, if he/she deems it appropriate.
• The Minister may require LNG Exporters to provide regular reporting of their LNG volumes.
• If there is more than one LNG Exporter associated with an LNG Project, LNG Exporters may be required to report cumulatively, on an LNG Project basis.
• If an LNG Exporter does not comply with a condition attached to its Export Permission, the Minister may revoke or vary the permission, or issue a new permission altogether.
The ordinary term of an Export Permission will be the duration of the relevant shortfall year.
To manage changes in circumstances during a licence period (company and market) the Minister may:
• vary an export permission if requested by an LNG Exporter, and the Minister is satisfied that the variation is reasonable and appropriate
• vary or revoke an Export Permission if an LNG Exporter has not complied with a condtion of the permission.
Similarly, an LNG Exporter may
• surrender their Export Permission to the Minister at any time.
This model provides the following features:
• If controls are invoked they will limit exports by LNG Projects only to the maximum extent that they are drawing from the market in net terms.
• It provides the LNG industry, which sets production and cargo levels n advance, with certainty around their licenced volumes for the following year. Once an Export Permission is set, the government cannot reduce it unless conditions are breeched.
• The ADGSM is implemented through Division 6 of the Customs (Prohibited Exports) Regulations 1958, in reliance on section 112 of the Customs Act 1901.
• The new regulation has a five year sunset (1 January 2023) with a review after two years.
• The ADGSM does not replace COAG-AEMO emergency gas market security measures which will continue to operate in the event of unexpected market security event.
• The Minister may revoke a determination of a domestic shortfall year at any time.
Key design elements:
• The ADGSM is implemented through Division 6 of the Customs (Prohibited Exports) Regulations 1958, in reliance on section 112 of the Customs Act 1901.
• The new regulation has a five year sunset (1 January 2023).
• The ADGSM does not replace COAG-AEMO emergency gas market security measures which will continue to operate in the event of unexpected market security event.
• The Minister may revoke a determination of a domestic shortfall year at any time.
The gas supply industry will be able to work with government and the market operator at any stage prior to, or during, this process to find a non-regulatory or commercial solutions to identified potential shortfalls. If satisfied the Minister can elect not to initiate or to terminate the process.

Calculating TMSO, the EMSOs and Provisional Export Permissions

Step A

Following a declaration of intention to determine if the following year is a shortfall year and receiving submissions from stakeholders, the Minister will consider each part of the domestic gas market to determine if a shortfall exists.

The assessment will incorporate advice from market forecasters like AEMO, information from the ACCC, sales gas forecasts from gas producers, production forecasts from major industrial consumers, etc.

The Minister's Determination will be based on his or her assessment of the best available information. The Minister may exercise his or her discretion and judgement in considering the credibility and integrity of any information received.

If the Minister determines that a shortfall is likely, **move to Step B.**
The Minister's Determination for export controls will apply Australia wide (rather than just to the part of the Australian domestic gas market which is identified as being in shortfall). During a domestic shortfall year, all exports of LNG will be prohibited unless exporters hold an Export Permission.

Note:
This assessment will take into account a range factors including:
- the extent to which exports contribute to shortfall
- external factors influencing the market
- the materiality and price impact of a shortfall
- the ability for exporters to redirect gas to the domestic market
- the availability of an industry-led solution to an identified shortfall.

Step B

The Minister then determines a *Total Market Security Obligation* (TMSO). The TMSO is a proportion of the Australian gas market shortfall that the Minister considers may be met by imposing export controls on LNG projects, to incentivise them to increase net gas supply to the domestic consumers.

The Minister will initially determine a provisional TMSO for consultation before finalising.

Concurrently with determining the TMSO, the Minister will determine each LNG Project's projects' *net market position* of either a net-deficit or a net-contributor.

An LNG Project is in net deficit if either the LNG Project's:

1) total gas used > Own Gas + third party export compatible gas; or
2) gas purchases from the domestic market > sales to domestic market.

LNG Project Tenements will be used to determine Own Gas and Export Compatible Third-Party gas (see purple box for definitions).

Note:
This assessment will take into account a range factors including:
- strategic behaviour
- the extent to which non-export factors are driving market outcomes.

Step C

The Minister allocates the TMSO on a pro-rata basis across all LNG Projects in net-deficit. The proportion of the TMSO allocated to a net-deficit LNG Project is that LNG Project's Exporter Market Security Obligation (EMSO).

If there is only one LNG Project in net-deficit, then that Project's EMSO will be equal to the TMSO. LNG Projects will be permitted to meet their EMSO by reducing their export quantities, or making additional gas available to the domestic market.

Where there are no LNG Projects in net-deficit, the Minister will not allocate the TMSO to any LNG Projects.

Note:
When determining the TMSO and each LNG Project's EMSO, the Minister may take into account the past performance of LNG Projects and LNG Exporters.

Step D

The Minister may grant the following provisional Export Permissions for each LNG Project

An **Unlimited Volume *(UV)*** permission is granted to projects assessed as being a net-contributors, and unable to deliver gas at a reasonable price and located in a separate market are allocated a provisional.

An **Allowable Volume (AV)** permission allows a maximum volume of LNG to be exported from a specific project over the market shortfall year. Maximum exports are typically equal to an LNG project's EMSO subtracted from total export quantity.

The Minister may grant an Export Permission subject to conditions, such as reporting of volumes.

Note:
The Minster may vary an Export Permission with consent of LNG Exporter. The Minister may approve a variation if an LNG Project has sources new gas, additional market supply has become available, or the forecast shortfall has not eventuated. The Minister can also revoke an Export Permission if conditions have not been complied with.

Key definitions:

- An LNG Project's **Own Gas** is gas produced from one or more tenements:
  - owned by the LNG Project; or
  - wholly or partly owned by one or more entities of the LNG Project, where:
    - the gas is contracted directly to supply the LNG Project; and
    - the gas was primarily developed for the purpose of the export.
- An LNG Project's **third party export compatible gas** is gas produced from tenements owned by a third party, where:
  - the gas is contracted directly to supply the LNG Project; and
  - either:
    - The gas was primarily developed for the purpose of supplying the export market; or
    - The contract for the supply of gas was entered into for the purpose of supplying the LNG Project, before a final investment decision was made in relation to the LNG Project.
- An LNG Project's **total gas used** is the sum of the gas
  - Proposed to be exported; and
  - Any other gas that is forecast to be consumed or lost in the LNG Project's operations.

5 Net Benefits

The purpose of this section is to provide an indication of the likely impacts arising from implementation of the options outlined in Section 4. It does this by analysing the costs and benefits of each option, and comparing the net benefit against the status quo.

5.1 Impact analysis: status quo

Overview

If the status quo is maintained, then the Government will have no recourse to influence LNG exporter behaviour.

If this is the case, then there is nothing to suggest that the gas supply situation will improve for domestic and commercial gas consumers, particularly on the east coast. Despite the Government's announcement to introduce export controls, some companies have signalled their intent to increase LNG exports. Recent domestic short-term prices have risen above LNG netbacks (measured against spot prices) in Queensland, New South Wales, Victoria and South Australia. Further, there have been reports of industrial gas consumers receiving short, medium and long-term contract offers at higher than netback prices[7]. This indicates that the domestic market lacks confidence that there will be a sufficient gas supply in the future.

The supply shortfall identified by AEMO in the 2017 GSOO also has potential implications for system security within the National Electricity Market (NEM). Gas Powered Generation (GPG) is required in the NEM to provide operational flexibility by increasing and decreasing generation relatively quickly to meet changing demand when wind and solar generation is unavailable. The risk of short-term interruptions of electricity demand will increase when there is not enough GPG available to increase generation fast enough to meet demand.

If there is a gas supply shortfall, then there is a risk that large consumers such as manufacturers will be forced to reduce or cease production due to supply uncertainty. If the market perceives that there will be a shortfall, this could also have the effect of inflating future gas supply contract price offers. In both cases there are significant flow on effects to manufacturers, consumers and employees.

Costs

By its nature, maintaining the status quo would not result in any additional regulatory costs for the gas industry or Government. Nor would it change the current market situation where long-term take or pay export contracts, and the economics of LNG facilities are resulting in gas being exported at prices lower than those being offered to the domestic market. However, it means that domestic gas consumers would continue to bear the risk of insufficient gas to supply both domestic and export demand. These consumers include households, and gas-dependent businesses that employ thousands of Australians.

This could result in the untenable situation where domestic gas consumers have less reliable supply, and are paying more than their overseas counterparts that source their gas from Australia. In 2014, BIS Shrapnel estimated that a shortfall would cost the east coast manufacturing sector a minimum of $14 billion[8].

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[7] Ai Group, 15 March 2017, media release

[8] BIS Shrapnel, September 2014, *The Economic Impact of LNG Exports on Manufacturing and The Economy*

Benefits

Maintaining the status quo would provide greater certainty to the LNG export industry and other gas market participants. However, most gas market participants understand the need for the Government's concern about security of supply.

Net benefit

The cost of doing nothing outweighs the benefits. It is unacceptable to take no action.

5.2 Impact analysis: industry led agreement to guarantee adequate supply

Overview

The Government would seek an agreement from exporters and other producers to guarantee an adequate gas supply to the domestic market. This was the objective of the meetings between the Government and industry in March and April 2017. Throughout the industry meetings, the Government made it clear that its preference was for industry to respond of its own volition, and improve supply and price outcomes without the need for Government intervention.

This approach was effective in getting gas producers and pipeline operators to guarantee that they would supply enough gas to the NEM in times of peak demand (e.g. in heatwaves)[9,10]. However, east coast gas producers were unable to make a broader guarantee that the domestic gas market – not just the NEM – would be supplied with sufficient gas. As the Government continued its consultations (detailed in Section 6), industry did not provide evidence to suggest that such an agreement could be reached. Additionally, it is unclear how this option could be enforced to an extent that the domestic gas market had confidence that supply was assured.

Costs

This option would likely have no additional regulatory costs for LNG exporters.

Once the agreement was developed, this option is likely to have ongoing business costs, depending on the terms of the agreement. As the agreement would be co-designed and enforced by industry, any additional costs would be taken voluntarily, and would form part of the exporters' social licence to operate; i.e. the costs would be an industry-accepted "cost of doing business".

A major drawback of this option is that the Government would not be in a position to intervene if exporters did not provide the domestic market with enough gas. By the time a shortfall was apparent, the negative effects would already be passed on to domestic gas consumers in the form of lower reliability and higher prices. In other words, the risk of an export-driven supply shortfall (and the associated flow-on effects) would still be borne by domestic gas consumers. This presents significant risks of industrial demand destruction.

Further, it is unlikely that LNG exporters would agree to guarantee a quantity of gas to the domestic market that is deemed sufficient by consumers and the Government. Such agreements may also take a long time to be reached. As discussed in Section 3, the Government has previously met with gas exporters and producers on the east coast, and given them the opportunity to improve supply and price outcomes of their own volition. Despite making progress, not all of the east coast LNG exporters satisfactorily outlined their plans to contribute a sufficient supply of gas to the domestic market. While the costs are unlikely to reach the levels of the status quo option, it is likely that this

[9] The Prime Minister, the Hon Malcolm Turnbull, 15 March 2017, media release.
[10] Minister for the Environment and Energy, Minister for Industry, Innovation and Science, Minister for Resources and Northern Australia, 29 March 2017, media release.

option would result in some users exiting the market, resulting in a loss of jobs and economic output.

Benefits

A commitment from exporters to provide the domestic market with an adequate supply of gas might decrease the likelihood, and perceived likelihood of a shortfall. If this happened, then this would ease supply and price pressures. However, unless the agreement outlined substantial consequences for failing to adequately supply the domestic market, these positive effects are unlikely to eventuate and are potentially small in magnitude.

Net benefit

If this option fails, or is perceived to be likely to fail, then it is likely to lead to reduced economic activity in Australian gas-reliant industries. Additionally, the likelihood of realising any benefit is small. The net benefit of this option is uncertain and potentially negligible.

5.3 Impact analysis: gas reservation

Overview

A gas reservation policy would require exporters to make a quota of gas available to the domestic market. Although a reservation policy would provide extra security to the domestic market, it would also present a number of difficulties.

Firstly, it would be difficult to target this option only at exporters, in order to meet the policy objective of preventing an export-driven shortfall. This is because it is hard to identify the point along the value chain at which the percentage should be applied, for example:

- If the percentage is applied to the gas that an LNG exporter produces from its own fields, then it dis-incentivises the development of new gas, and encourages exporters to purchase from third parties. This would contradict the Government's intent to encourage a productive, socially responsible LNG industry.
- If the percentage is applied to the third party producers from which an LNG exporter purchases gas, then it pushes the cost of mitigating an export-driven shortfall onto producers that aren't involved in exports, without having any impact on exporters.
- If the percentage is applied to an LNG exporter after it purchases gas from a third party, then, using the 15 per cent example, an exporter could just purchase 115 per cent of the gas it wanted, and sell the remainder to the domestic market. This would do nothing to ease supply pressures for domestic gas consumers.

Secondly, if a blanket reservation policy was effectively targeted at exporters, it would spread the cost of preventing a shortfall across projects that did not contribute to it. This would shift accountability away from exporters that have had a negative impact on the domestic market onto exporters whose operations may have resulted in a net benefit to the domestic market.

Similarly, if the percentage was applied based on the quantity of LNG that an exporter ships overseas, or the exporter's nameplate capacity, then it would not discriminate between an exporter that produced all of its feed-gas itself, and an exporter that sourced all (or part) of its gas from third parties. This would not incentivise exporters to produce additional gas.

Thirdly, a reservation policy would increase the real cost to LNG projects in circumstances where the domestic market was already well supplied. This would reduce the potential profitability of LNG exports. However, the flip side of this is that when LNG projects are exporting large quantities of

LNG, the domestic market would be supplied with a large quantity of gas. This extra supply could help drive down domestic prices.

Fourthly, it would be challenging to develop a comprehensive gas reservation framework that could be agreed by the Australian and all State and Territory Governments in Australia within a reasonable timeframe to address near term market concerns. It is likely that such framework would only be prospective rather than retrospective which would mean that it would only begin to incrementally influence market supply as new gas supply projects were developed rather than having an immediate or near term impact.

Costs

There are negligible regulatory costs associated with LNG exporters complying with gas reservation policies.

There is, however, potential for substantial business costs. As an example, consider the three east coast LNG exporters operating out of Gladstone, who have a combined nameplate capacity of 25.3 million tonnes per annum (Mtpa). Five per cent (a third of WA's 15 per cent reservation policy) of this is nearly 1.3 Mt, which is equivalent to 70 PJ, or just over a tenth of east coast domestic demand. At the March 2017 export unit value for Australian LNG ($8.30/GJ[11]), this volume would be worth over $580 million[12]. Depending on the price of gas domestically, compared with internationally, this could have significant impacts on LNG exporters' profitability, particularly if the domestic market was already adequately supplied. This is evident in Western Australia, where domestic spot prices are well below LNG spot prices[13]. Lower domestic prices could also discourage exploration and development aimed at supplying the domestic market.

The retrospective application of a gas reservation policy would introduce the risk of LNG exporters not being able fulfil contractual volumes with buyers, if gas field production could not be ramped up to meet the additional supply required under the reservation requirements. Undelivered LNG cargoes would incur penalties, however the terms of LNG sales-purchase contracts are confidential, and it is therefore not possible to quantify the cost on exporters or if force majeure clauses would apply.

Applying a blanket gas reservation policy would also carry a high level of sovereign risk. LNG projects require billions of dollars in upfront exploration and infrastructure investment. Australian and overseas investors make their investment decisions with the knowledge that Australia has a historically stable regulatory environment. Applying a reservation policy retrospectively would reduce the profitability of all LNG projects by changing the rules under which investors made their final investment decisions. It might also impact the ability of exporters to meet their contracts[14], given their economically viable levels of production, and would inflexibly change the parameters under which the exporters can do business.

If the reservation policy was applied at all times (see Section 4.3), then it is possible that the domestic market would become oversupplied, and prices would become artificially low. This would

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[11] Australian Bureau of Statistics

[12] This number provides an idea of the scale of the gas' value. It is not the cost to exporters because they would still be receiving an income from selling the gas to domestic gas consumers. Additionally, it should be noted that not all east coast exporters are currently producing at their respective nameplate capacities; and a fixed five per cent reservation policy is relatively conservative.

[13] gasTrading Australia, May 2017, *Historical prices and volume*

[14] Consequences of breaking the terms of these contracts are commercial in confidence.

have the effect of shifting a cost from domestic gas consumers, to producers. Several studies have argued that this results in an overall loss to the economy, because resources could be allocated more efficiently[15,16]. It should be noted that the Deloitte report that argues this point compares the effects of a reservation policy, to an environment that is entirely market driven. This is not currently the case in Australia, because some state and territory government policies restrict the exploration and development of onshore gas. An alternative view is that the lower gas prices would benefit the economy in the long run, due to reduced cost for industrial gas users like manufacturers[17, 18].

There are also potential long term costs for consumers. The ACCC's 2016 *Inquiry into the east coast gas market* investigated the benefits of a gas reservation policy. After considering evidence from the former Bureau of Resources and Energy Economics, and the Western Australian Economic Regulatory Authority, the ACCC recommended against reservation policies "given their likely detrimental effect on already uncertain supply". This is because, in the long run, a reservation policy has the potential to reduce export profitability, resulting in reduced levels of exploration and development, and increased pressure on supply.

Finally, under the Constitution, any regulation from the Australian Government must not discriminate based on geographical location. Therefore, a blanket reservation policy would impact exporters operating out of all Australian states and territories. Given that it is not currently physically, or economically viable to transport gas between the west and east coasts, a reservation policy would potentially impose a cost on exporters that are not in a position to increase supply to consumers experiencing a shortfall on the other side of the country.

Benefits

The benefits of a gas reservation policy centre on the guarantee of a dedicated long term supply of gas for domestic gas consumers. Internationally, several countries have gas reservation policies, including Israel, Indonesia and Egypt that reserve between 30 and 60 per cent of gas production for domestic users. Providing a long term dedicated supply, particularly for industrial gas users such as manufacturers, is important as it provides certainty on the cost and availability of a critical business input.

In the basic chemical manufacturing industry, for example, gas accounts for about 25 per cent of intermediate input costs. In other heavy manufacturing industries like glass and glass product manufacturing, ceramic product manufacturing and polymer product manufacturing, gas accounts for at least 10 per cent of the input costs. Therefore increasing gas prices could have a significant impact on the profitability of these industries. These industries are also significant employers. The polymer product manufacturing industry, for example, employs over 31 000 people throughout NSW, Victoria, Queensland and South Australia.

Western Australia is the only Australian state with a broadly applied gas reservation policy. The policy, introduced prospectively rather than retrospectively, reserves 15 per cent of gas from each LNG export project for the domestic market, with allowances for negotiations between the state and LNG companies to occur on a case-by-case basis. It should be noted that the east and west coast markets have different characteristics (e.g. infrastructure constraints, demand profiles), and it is difficult to separate the impact of a reservation policy from these factors.

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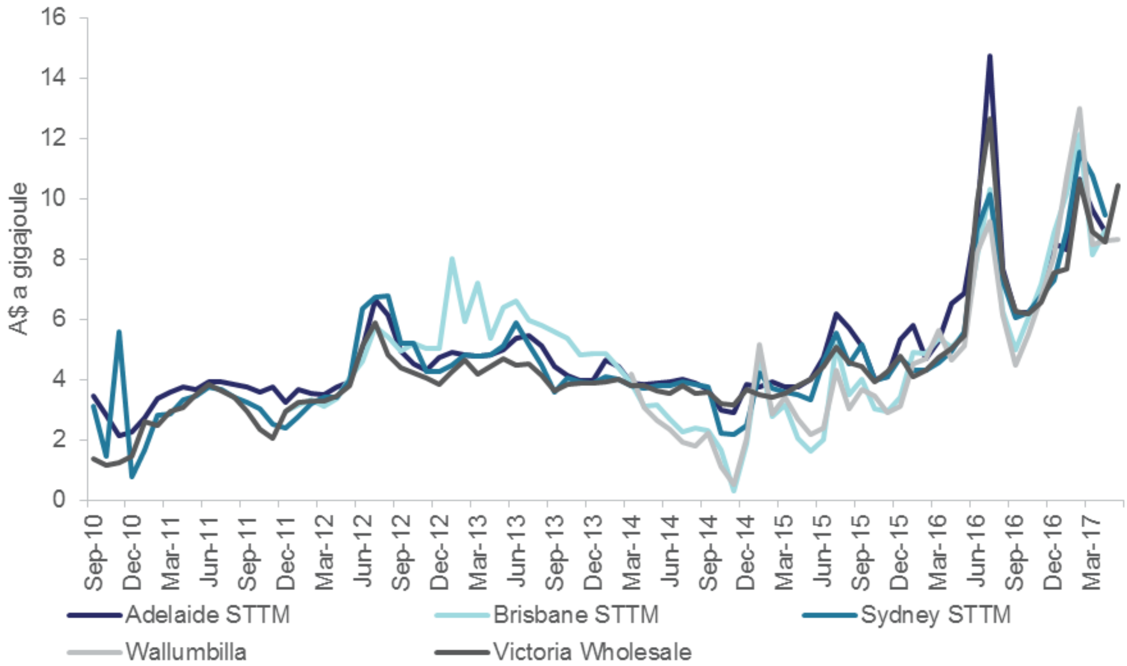
[15] Deloitte Access Economics, October 2013, *The economic impacts of a domestic gas reservation*
[16] Department of Industry, Innovation and Science, April 2015, *2015 Energy* White Paper
[17] BIS Shrapnel, September 2014, *The Economic Impact of LNG Exports on Manufacturing and The Economy*
[18] Deloitte, July 2014, *Gas market transformations – Economic consequences for the manufacturing sector*

However, the western domestic gas market has significantly lower gas prices compared to the east coast. As outlined in Figure 1, east coast spot prices have increased as LNG production has ramped up in Gladstone[19]. This increase is significant, with gas in April 2017 valued at roughly $9/GJ, which is about triple the price in September 2010. In Western Australia, domestic spot prices are currently below 2009 levels, at $4-5/GJ (see Figure 2) despite LNG export volumes nearly doubling. Domestic spot prices on the east coast have also been significantly more volatile than on the west coast.

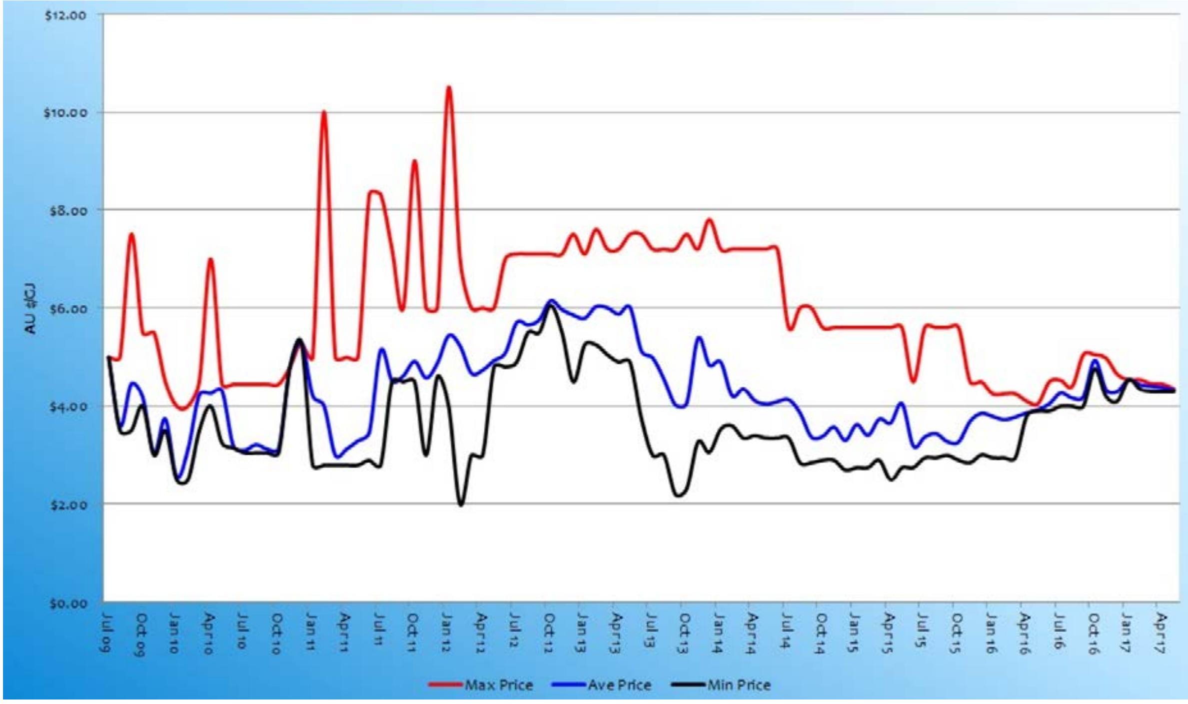
These trends indicate that Western Australia's domestic market has a secure supply, regardless of how much LNG is exported. It is probable that this security is achieved through Western Australia's reservation policy, as evidenced in short-term trading market (STTM) pricing. It should be noted that Western Australia's gas is primarily sourced from offshore conventional resources.

Figure 1: East coast short term gas – daily prices (monthly average)[20]



[19] Department of Industry, Innovation and Science, March 2017, *Resources and Energy Quarterly*
[20] Australian Energy Market Operator, May 2017, *Data*.
Note that all prices are 'ex ante' prices, except for the Victoria Wholesale price, which is ex post.

Figure 2: Western Australian short term gas – daily prices (monthly average)[21]



According to BIS Shrapnel, Western Australia's reservation policy has been able to supply stable, secure and affordable energy to users, and enabled development of Western Australia's mining, minerals processing, power generation and manufacturing industries. Gas reservation has also provided price competition to other alternative energy sources, such as coal, ensuring more competitive energy pricing overall[22]. The Western Australian Government also considers the availability of low cost gas to have been a major driver of the State's strong economic growth over the two decades to 2006[23].

Net benefit

In comparison to the status quo, a permanent gas reservation policy would have a substantial short to medium term net benefit for domestic gas consumers, but come at a high cost to all LNG exporters, and potentially Australia's reputation as a low-risk destination for international investment. In the long run, the impact of restrictions on LNG projects is likely to result in a reduction in exploration and development of new fields, because production in Australia has historically been the direct result of LNG projects. This could diminish or negate any long term benefit to consumers.

5.4 Impact analysis: export controls

Overview

Export controls would work by limiting the quantity of LNG that gas exporters are licensed to ship overseas. This would increase the amount of gas available to domestic gas consumers, by incentivising exporters to redirect their production to the domestic market. There are a number of

[21] gasTrading Australia, May 2017, *Historical prices and volume*
[22] BIS Shrapnel, September 2014, *The Economic Impact of LNG Exports on Manufacturing and The Economy*
[23] WA Department of Industry and Resources, *WA Government Policy on Securing Domestic Gas Supplies: Consultation Paper*, February 2006, p.2.

ways to implement export controls, which are discussed in Section 8. This section focuses on the costs and benefits of implementing the ADGSM, which is outlined in Section 4.4. Importantly, the ADGSM would only result in export controls if the domestic market was not adequately supplied.

Costs

The regulatory costs to industry associated with this option are largely administrative. Costs have been estimated based on the labour required to comply with each step of the process. This RIS estimates the total regulatory cost to the gas industry to be approximately $180,000 per annum. A full breakdown of this estimate, including assumptions and caveats is detailed in Appendix B. This figure is relatively insignificant in an industry where the yearly revenue for an export project is measured in billions. A regulatory offset has not been identified. However, DIIS is seeking to pursue net reductions in compliance costs and will work with affected stakeholders and across Government to identify regulatory burden reductions where appropriate.

It is also worth noting that the annual regulatory burden is likely to be lower than estimated in most years, because the Minister's determination point (see Appendix B) of the export controls process would only be instigated in the event that a domestic shortfall was likely.

The multi-step process also means that export controls would not be applied all the time. Therefore, the cost for businesses to redirect gas into the domestic market would not be permanent, as would be the case for a permanently applied gas reservation policy[24]. Additionally, exporters would only be impacted to the extent that they were contributing to a shortfall. Both of these design features lower impact on industry, in comparison to a gas reservation policy. However, there would still be an additional cost in comparison to the status quo.

Like the reservation option, there are other potential negative impacts from the prospective application of export restrictions. This includes the risk of LNG exporters not being able fulfil contractual volumes with buyers if gas field production could not be ramped up to meet the additional supply required to meet Export Permission conditions. Undelivered LNG cargoes would likely incur penalties, however the terms of LNG sales-purchase contracts are confidential, and it is therefore not possible to quantify the cost on exporters.

Applying export controls also carry a high level of sovereign risk. LNG projects require billions of dollars in upfront exploration and infrastructure investment. Australian and overseas investors make their investment decisions with the knowledge that Australia has a historically stable regulatory environment. As with a reservation policy, it is likely that Australia's attractiveness as a destination for investment in gas resources and infrastructure would be affected. At this point it is difficult to determine the extent of the damage to Australia's reputation as an investment destination in the gas sector and this will likely depend on the frequency and depth at which export controls are applied and the nature of LNG contracts.

The best assessment is that the cost to industry would be less than the equivalent cost under reservation, because the total amount of gas redirected would be linked to exporters in a shortfall market rather than a sector wide and permanent regulatory requirement. The number of LNG exporters captured by export controls would also be lower than under a reservation policy. This is

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[24] As discussed in Section 4.3, it should be noted that a multi-step process could also be added to a reservation policy; i.e. it could be implemented so it only came into effect in the event that a shortfall was likely. However, a blanket reservation policy would spread the costs equally among all exporters, rather than targeting the costs at projects that contributed to the shortfall.

not to say the cost of redirecting gas from export to the domestic market is not potentially significant but in the current market circumstance where domestic wholesale prices are at or above export parity, it could even be possible for the exporter to arbitrage across both markets through a combination of domestic diversion and LNG swaps to minimise losses or even gain value.

Although there may be a small degree of regulatory burden for gas producers, exporters and large consumers to generate production and consumption forecasts, this is not directly a result of this policy option; it is a requirement of other Government initiatives, including market reform work led by the ACCC, and improved forecasting by organisations like AEMO. Therefore, this RIS does not include generating this information as an additional business cost. The process of collating the information and supplying it to the Government is captured in the regulatory burden costing in Appendix B.

Despite these impacts, the ADGSM is still a reasonable option for two reasons. Firstly, the ADGSM would have a substantial net benefit on security in domestic supply and consequently lower prices for domestic consumers. Secondly, the alternative to targeted export controls, which would still address the policy problem adequately, is a broader policy like gas reservation. As discussed in Section 5.2, a blanket policy would result in higher costs (and therefore a lower net benefit), thereby making it less desirable.

If enacted, the ADGSM would prevent LNG exporters from selling a certain volume of gas to the export market and increase the availability of supply to the domestic market. As spot prices in export markets are currently below international contract prices, it is anticipated that exporters would make up the shortfall in the spot market.

Failure to ensure an adequate supply of gas would have significant negative effects on industrial gas users, the gas power generation sector and residential gas consumers.

Benefits

Export controls that are linked to projected shortfalls, would ensure that the domestic market is supplied with an adequate quantity of gas. This would help to combat market uncertainty, which may, in turn, reduce pressure on prices.

Gas reliant industries (detailed in Appendix A) are the other main beneficiary from export controls. These industries employ more than 65 000 Australians and their dependence on gas makes them sensitive to any price fluctuations.

Other direct beneficiaries would include the 50 per cent of Australian households who have mains gas. For these households, the increased availability of reasonably priced gas would have a direct reduction in cost of living expenses. Energy bills make up a significant part of monthly household expenditure. For example, in Victoria, energy services (which include both gas and electricity) are estimated to cost approximately $550 per month for an average house and $355 per month for an average apartment[25]. Reductions in gas prices, therefore, will result in a meaningful difference to Australian households, especially as reductions in gas prices are likely to cause price competition in energy sources and place downward pressure on energy prices more broadly.

[25] Victorian Government, *Cost of living in Victoria- Cost of Domestic Supplies, Home Services and Utilities*

Net benefit

Compared to all other options, including the status quo, the export controls outlined in the ADGSM have the strongest likelihood of securing an adequate supply of gas for domestic users, with the least market distortions. In times when the market was sufficiently supplied, the ADGSM would not be triggered.

Non-regulatory costs would only be imposed in the event that a domestic shortfall was likely. Additionally, the mechanism would only impose business costs on exporters that were in net deficit (i.e. contributed to the shortage). This means that the overall cost would be proportionate to the exporters' role in contributing a shortfall, while the benefit to consumers would be substantial and widespread. As a result, the net benefit of this proposal is greater than the net benefit of all other options, including the status quo.

6 Consultations

Between March 2017 and May 2017, the Government had steady engagement with industry in order to deliver Australian households and businesses with an adequate supply of gas at reasonable prices. The Government will continue to collaborate with industry, as it refines the ADGSM to better safeguard Australia's domestic gas supply. This section summarises the consultation process.

It should be noted that the consultations focussed on the ADGSM. However, the industry provided feedback on additional policy options, including some additional options for implementing export controls, which are discussed in Section 8. Some additional options were considered unfeasible, and/or did not solve the policy problem. These options were not included in this RIS.

6.1 Past consultations

Initial 'round table' consultations

Before considering intervention in the gas market, the Prime Minister hosted meetings with east coast gas producers and exporters on 15 March 2017 and 19 April 2017. At those meetings, the Government sought commitments:

- from gas producers to make more gas available to the domestic market as soon as possible
- from LNG exporters to have a net contribution gas to the domestic market, rather than 'drawing down' on domestic supply.

In addition to meeting with gas producers and exporters, on 29 March 2017, the Government met with gas pipeline operators, and relevant peak bodies.

Throughout the industry meetings, the Government made it clear that its preference was for industry to respond of its own volition, and improve supply and price outcomes. However, the Prime Minister also made it clear that the Government would intervene if gas producers did not meet commitments to address the current tightness in the domestic market. Despite making progress, not all of the east coast LNG exporters satisfactorily outlined their plans to contribute enough gas to the domestic market to offset the impact of their operations.

Consultation on the ADGSM

Following the unsatisfactory outcome of the Government's initial industry meetings, Senator the Hon Matthew Canavan, Minister for Resources and Northern Australia, wrote to industry and government stakeholders in late April 2017 to inform them of the proposed ADGSM. His letter included a discussion paper, which outlined the ADGSM's initial design. Minister Canavan requested feedback on the ADGSM, and asked for participation as the Government continued to develop the mechanism. Minister Canavan initially requested written submissions by 11 May 2017, but this deadline was later extended in order to allow for more comprehensive consultations.

DIIS conducted three meetings (4 May 2017, 11 May 2017 and 26 May 2017) with each of the joint venture partners involved in each of the east coast LNG projects. These meetings aimed to provide clarity about the policy intent of the ADGSM and its proposed operation. The meetings provided the exporters with the opportunity to critique the mechanism and offer improvements and alternative suggestions. At the meetings, DIIS encouraged out of session communication to help the mechanism to achieve its policy objectives, while minimising the burden on the LNG export industry.

On 15 May 2017, DIIS held a similar meeting for interested parties at the 2017 APPEA Oil & Gas Conference and Exhibition. This invitation was extended to all joint venture partners in LNG projects that operate out of the Northern Territory and Western Australia.

DIIS also had a number of meetings with individual companies when requested.

On 5 June 2017, exposure drafts of the regulations, guidelines and explanatory material for the ADGSM were released for consultation until 12 June 2017. Stakeholders including LNG projects, major gas users, peak body and consumer interest groups, and State and Territory governments, were invited to make submissions.

34 submissions were received from LNG projects, LNG producers, large gas consumers, businesses, State and Territory governments, other affected stakeholders, and members of the public. Feedback from the submissions was considered and informed the further development of the ADGSM.

DIIS also consulted with the Australian Government Department of Prime Minister and Cabinet, Department of Immigration and Border Protection, Department of Foreign Affairs and Trade, Department of the Treasury, and Department of the Environment and Energy.

During the week beginning 19 June 2017, DIIS conducted international consultations with major trading partners including Japan, South Korea, Malaysia and China.

In addition to the formal meetings, Minister Canavan has engaged directly with industry leaders in person, and by correspondence.

6.2 Planned consultations

The Government will continue to encourage industry to engage with DIIS, as it works towards finalising the mechanism.

Implementation of the ADGSM will build in further opportunities for consultations with industry in relation to the possibility of industry-led solutions which would preclude the need for export controls.

7 Recommendation

7.1 Recommendation and justification

This RIS considered four options to increase the security of Australia’s domestic supply by influencing LNG exporters.

The first option was for the Government to maintain the status quo, and leave the LNG export market unregulated. This option is untenable, because it leaves Australian gas consumers in a position of shouldering all of the risk of an export driven shortfall.

The second option was for LNG exporters to voluntarily agree to guarantee an adequate supply of gas to the domestic market. The net benefit of this option is negligible, because the likelihood of an enforceable commitment effectively preventing a shortfall, or perceived shortfall is low. As in the first option, the risk of an export-driven supply shortfall (and the associated flow-on effects) would still be fully borne by domestic gas consumers.

The third option was a blanket gas reservation policy. Compared with the first two options, this option is substantially more likely to meet the policy objective of securing an adequate supply of gas for domestic gas consumers. However, less restrictive options were available. If the reservation policy was permanent, it could also have negative effects on long term supply, because it dis-incentivises exploration and development. This would counter the positive short to medium term benefit to domestic gas consumers. The only viable non-permanent reservation method is equivalent to implementing export controls (see Sections 4.3 and 8.2 for further discussion).

The fourth option was for the Government to employ export controls. Compared to the status quo, the export controls outlined in the ADGSM have a strong likelihood of securing an adequate supply of gas for the domestic market. Compared with a blanket reservation policy, the ADGSM is likely to redirect less gas into the domestic market, so the short term benefit to consumers is less. However, the ADGSM is likely to impose a substantially smaller cost on LNG exporters, which would be in proportion to their contribution to a domestic shortfall. Although the regulatory burden is higher for export controls in comparison to the other options, the cost is negligible in comparison to other business costs incurred by the LNG export industry.

After considering all four options, **this RIS recommends export controls** as the most appropriate method to solve the policy problem. The preferred method of implementation is through the proposed ADGSM, as it would meet the policy objective more effectively than other export control designs (see Section 8).

However, the Government does not believe that export controls is the only solution to all of the issues with Australia's domestic gas markets. Export controls, and the implementation of the ADGSM, would complement other government, including CoAG Energy Council actions, which are designed to improve the efficiency, competitiveness and transparency of gas markets and increase the development of Australia's gas resources.

7.2 Stakeholder feedback

The stakeholder consultations described in Section 6 were centred on export controls, and the ADGSM. Although gas exporters understood the Government's rationale, they challenged the need for intervention. DIIS heard a number of arguments to this effect, including:

- The overarching cause of supply pressures is due to restrictive state and territory government policies.
- Exporters should not be held accountable for supply pressures if there are other market forces (e.g. declining field production) that are also placing pressure on supply.
- Wholesalers are having a larger impact on domestic prices than exporters.

The Government has taken this feedback into account and is undertaking separate actions to address non-exporter related issues with Australia's gas markets. However, none of these points justified Australian consumers bearing the risk and cost of export-driven shortfalls.

After voicing their opinions on the need for any regulation in the first place, industry stakeholders constructively provided feedback on how export controls would best work in practice, and the design of the ADGSM. DIIS heard a number of exporters' concerns, including the following.

- It is important for the mechanism to be temporary, because increasing supply is the preferred long term solution.
- The shipping schedules of many LNG exporters are finalised in the prior calendar year, following a period of contractual negotiations between LNG exporters and consumers. These schedules are difficult to change for logistical and contractual reasons.
- The complex commercial structures of different LNG exporters require the ADGSM to have robust definitions around the respective points of net-deficit assessment and licensing (see Section 4.4).
- There should be careful thought given to the definitions and methodology used to determine whether an exporter is in net deficit to the domestic market.
- There may be an incentive for different LNG exporters to 'game' the mechanism by engaging in anti-competitive behaviour.
- There needs to be provisions to ensure that accurate data (from both producers and consumers) are available and forecasting follows best practice.
- Cargo swaps are not an option for all exporters for contractual reasons.

The Government is continuing to refine the ADGSM, in consultation with industry stakeholders, to take into account the above points.

7.3 Caveats and qualifications

Industry consultations regarding alternative policy options to the ADGSM, did not yield effective or acceptable solutions to ensure reliable and affordable gas supply for Australian consumers[26]. Further detail on these alternative models is available in Section 8.2. In the absence of suitable alternatives, the ADGSM has been recommended as the best option for the Government to improve supply security for domestic gas consumers whilst also balancing exporters' interests.

The ADGSM is a temporary and targeted measure that will only be implemented upon formal certification, from the Minister for Resources, that there are reasonable grounds for doing so. Such a certification is subject to the Government receiving advice from the ACCC and market bodies such as AEMO, before determining the volume of gas required.

The implementation of the ADGSM will, as much as possible, accommodate for LNG exporters to honour their ongoing contracts, recognising that they may be subject to logistical constraints such as, for example, shipping schedules. Definitions and methodology used to determine whether an exporter is in net deficit to the domestic market will be made to obtain accurate data from both producers and consumers.

The ADGSM is expected to commence on 1 July 2017. However, there will be ongoing consultations with industry to find a suitable compromise that minimises the burden for both the Government and gas exporters, whilst achieving the policy objective of securing domestic gas supply. Further industry consultation may change how the ADGSM is implemented and how it may affect upstream production and joint ventures.

Risk mitigation and other implementation details are discussed in greater detail in Section 8.

[26] The Prime Minister, the Hon Malcolm Turnbull, 27 April 2017, media release.

8 Implementation

All aspects of the implementation process included in this section have been informed by consultation (see Section 6) and are subject to further development. DIIS is actively engaging with industry stakeholders to minimise implementation risks, and maximise the net benefit to Australia.

8.1 Steps to implementing the ADGSM

The Government has committed to introduce export control regulations by 1 July 2017. The export controls would be implemented by amending the Customs (Prohibited Exports) Regulations 1958. The Department of Immigration and Border Protection (DIBP) is the agency responsible for this legislation. However, as with export controls for uranium and diamonds, DIIS will have primary responsibility for policy and administration, but work closely with DIBP on these matters.

The following remaining steps required to implement the ADGSM are:

- further consultation with industry (both gas producers and consumers) on the design of the mechanism[27]
- industry consultation on the exposure draft and guidelines in early June 2017
- consultation in early June 2017 with Australia's LNG trading partners
- tabling of the regulation in Parliament, and the subsequent disallowance period of 15 sitting days.

After the regulation is made by the Governor General, and tabled in Parliament and is not subject to disallowance, the ADGSM could be activated by the Minister for Resources. The Australian Government currently does not prohibit the export of LNG; however they are required to report their exports by way of Export Declarations. The LNG industry would therefore transition from reporting at time of export (Export Declaration) to requiring to obtain a permit prior to time of export while continuing to report export details as required of a prohibited export, when the Minister determines there to be a shortfall in the LNG domestic market. To assist the industry with the transition, guidelines outlining the steps, responsibilities and timeframes involved will be developed. Each decision point would be appropriately timed to ensure companies, market bodies and the ACCC had sufficient time to consider and respond to requests. Through the Minister for Resources, DIIS would be responsible for all aspects of the administrative process required to implement the ADGSM (see Section 4.4 for a flowchart describing the process). Responsibility for each step is articulated in the guidelines.

Minister's Declaration

The Minister would make a public declaration of his/her intent to make a determination of whether export controls would be implemented in the forthcoming year. The determination would occur no sooner than 30 days after the declaration. After making the declaration, the Minister would write to:

- relevant market bodies and agencies (e.g. AEMO, ACCC) requesting advice on the potential for a domestic gas shortfall, and associated analysis
- LNG project managers, requesting information such as gas production figures or planned export volumes, for example.
- relevant Australian Government Ministers, for consultation and to notify them of his/her declaration.

[27] As part of the consultations, DIIS will seek feedback on the regulatory impact of the mechanism.

- any other stakeholders that the Minister considers appropriate.

Assessment and decision

After receiving submissions, the Minister would consider all relevant and available information. The Minister would then make a determination as to whether export controls would apply in the following year.

If no shortfall exists, the process would end. If the Minister determined that export controls should be implemented in the forthcoming year, then the Minister would determine exporter obligations and permitted export volumes as outlined in Section 4.4 . The method for determining obligations will be detailed in the guidelines.

Minister's Determination

The Minister would issue a public decision with a statement of reasons. The Minister would also write to LNG exporters advising them of any provisional Export Permission decision (if triggered) and reasons for the decision. Where practical, exporters would have 30 days to consider and respond to their provisional Export Permission determination and any conditions attached to it.

The Minister would then assess any relevant additional information before finalising Export Permissions. The granting of an Export Permission would be conditional on gas supply and production throughout the permission period matching information supplied to the Government as part of the process.

An Export Permission period would apply from 1 January to 31 December of the following year.

Export Permissions would be based on a quantity of gas (linked to its energy content), rather than the number of cargoes. DIIS would be responsible for monitoring compliance of the export volumes for LNG companies subject to Export Permissions. DIBP's role would be to provide export information to DIIS 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).

Implementation risks

The Prime Minister has requested export controls be implemented by 1 July 2017 to respond to the risks to the economy resulting from a potential shortfall of supply to the domestic market.

Consultation on the framework with impacted LNG exporters, market bodies and the ACCC has occurred within a short timeframe as it is a priority to minimise any unintended consequences. Consultation with industry on the design of the mechanism occurred on the following dates: 4 May, 11 May, 15 May and 26 May 2017. In addition to this, *ad hoc* consultations will serve to address further issues.

Reviewing the mechanism

The ADGSM is intended to be a temporary intervention in the market. It is intended to only operate for five years (to 1 January 2023) and will be subject to a review after two full years of operation.

The review will evaluate the efficacy of the mechanism by analysing if export controls have made a material impact on reducing supply shortages to the domestic market. This will include reviewing the behaviour of exporters, to determine if restrictions (or threat of restrictions) on export volumes have improved domestic gas availability over time.

The review will also consider whether gas users have had improved access to gas and whether demand destruction had occurred due to industry closures. Administrative aspects of the mechanism would also be reviewed to determine if steps and timeframes for information gathering from market bodies and exporters restricted the Minister’s ability to make informed decisions.

Analysis of the performance of the policy against its objectives will take place throughout the operation of the ADGSM.

8.2 Alternatives to the ADGSM for implementing export controls

The impact analysis in Section 5 uses the proposed ADGSM design to estimate the regulatory costs, because it was deemed to be the most feasible and beneficial implementation method. This section outlines several alternative methods to implement export controls, including anonymous suggestions from industry stakeholders.

Gas-sourcing model

Under this model, LNG exports would be permitted where the exporter can demonstrate that feedstock gas was wholly (or partially with a specified minimum amount) derived from designated ‘export-compatible fields’. While this model may be preferable to exporters as it offers them more flexibility if ‘export compatible fields’ can be unambiguously identified, it could potentially involve a high level of regulatory burden to ensure that exported gas is derived from said ‘export-compatible fields.’ Moreover, this model may not actually increase the volume of gas available to the domestic market. Therefore, this model compares unfavourably to the ADGSM, which only requires action in the incidence of a shortage of supply to the domestic market and results in targeted, temporary changes to exports.

Equally distributed restrictions, or restrictions linked to gas volumes

Under this method of implementation, export restrictions would either be applied equally between LNG projects (i.e. all exporters get their exports restricted by a fixed percentage of the shortfall), or linked to the scale of operations (e.g. via nameplate capacity, or realised export volumes). These models are similar to a reservation policy in that they would impose an additional cost on exporters, regardless of whether their operations provided the domestic market with more gas. This would also disadvantage exporters that responsibly developed their own gas supplies, which contradicts the Government’s support of a productive, socially responsible LNG industry and would reduce the incentive for exporters to develop new fields. Compared to the targeted nature of the ADGSM, this model poses a higher level of intervention in exports without achieving a higher level of security for the domestic market.

Future contracts model

This model would not impact on gas sold as part of existing long term export contracts; as licensing would apply only to spot cargoes and future long term contracts. Export restrictions based on this model would have relatively certain impacts on exporters, however this method will not solve the problem of a potential domestic gas shortage in the short to mid-term. Relative to the ADGSM, it would reduce incentives for exporters to develop new sources of gas.

9 Appendices

9.1 Appendix A: Gas use statistics

Manufacturing industries most exposed to energy price shocks.

Analysis of the Australian Bureau of Statistics (ABS) Australian System of National Accounts Input-Output tables indicate that the six manufacturing industry groups with the most significant exposure (share of total intermediate inputs) to gas price fluctuations are as summarised in Table 1, with *Basic Chemical Manufacturing* being the most exposed. Note, these data are on a national basis and does not disaggregate to the level of specific regions susceptible to a domestic gas shortfall, such as the east coast gas market.

Table 1 Australian Industries most exposed to gas and energy price shocks, including through direct inputs with high energy shares (2013-14)

Manufacturing and Other Product Group	Gas Share of Intermediate Inputs	Value Share of Intermediate Inputs Exposed to Energy* Price Shocks	Value Share of Total Production Costs Exposed to Energy* Price Shocks	Average Employment – Year Ending March Quarter 2017
Basic Chemical Manufacturing	25%	27%	18%	5,275
Glass & Glass Product Manufacturing	13%	22%	11%	5,700
Ceramic Product Manufacturing	11%	18%	10%	5,175
Polymer Product Manufacturing	10%	18%	9%	31,675
Petroleum & Coal Product Manufacturing	10%	17%	10%	5,650
Plaster & Concrete Product Manufacturing	9%	14%	9%	12,425
Subtotal				**65,900**
Electricity Generation	8%	39%	22%	N/A

* Energy = Gas + Electricity; Departmental calculations.

Source: ABS (2016) 5209.0.55.001 Australian National Accounts: Input-Output Tables - 2013-14, Table 5; ABS (2016) 5215.0.55.001 Australian National Accounts: Input-Output Tables (Product Details), 2013-14; ABS (2017) 6291.0.55.003 - Labour Force, Australia, Detailed, Quarterly, Feb 2017.

9.2 Appendix B: Cost analysis of the ADGSM

This section follows the chronological process of the ADGSM to identify the regulatory burden on industry. It then outlines key assumptions that were included in the costing model. A regulatory offset has not been identified. However, DIIS is seeking to pursue net reductions in compliance costs and will work with affected stakeholders and across Government to identify regulatory burden reductions where appropriate.

Cost summary

Table 2, Table 3, and Table 4 detail the regulatory costs of the ADGSM for a single LNG project. The estimates in each table are inclusive of the activities of all joint venture partners involved in the project. Estimates of hours taken for industry to complete regulatory tasks are based on the administrative effort required.

Table 2 breaks down the regulatory cost to a business when the Minister for Resources 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, LNG exporters, and Ministers	No cost to industry			
LNG project operator develops submission including views on market outlook, and information on forecast production and consumption	Project planner	22.5	131.92	2968.24
	Planning manager	1	211.07	211.07
LNG project operator circulates submission to joint venture partners	Project planner	1	131.92	131.92
Joint venture partners assess the submission, and determine if changes are required.	Planning manager	12	211.07	2532.89
	Executive	4	452.57	1810.28
LNG project operator amends the application as per requests from individual joint venture partners	Project planner	7.5	131.92	989.41
	Planning manager	1	211.07	211.07
Joint venture partners reassess the submission	Planning manager	8	211.07	1688.60
	Executive	2	452.57	905.14
LNG project operator submits the application	Project planner	1	131.92	131.92
Total				**$ 11,580.55**

Table 3 breaks down the regulatory cost to a business when the Minister makes an assessment about whether export controls will apply in the following year.

Table 3: Estimate of regulatory costs for one LNG project when the Minister makes an assessment

Activity	Worker type	Total hours	Labour rate ($/hr)	Cost ($)
Government analysis of data, and determination of shortfall	No cost to industry			
Government calculation of each exporter's net deficit				
Government develops provisional permissions				

Table 4 breaks down the regulatory cost to a business if the Minister makes a determination to invoke export controls (described in the flowchart in Section 4.4).

Table 4: 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 joint venture members	Planning manager	1	211.07	211.075
Joint venture partners formulate an opinion about the government feedback and licensing.	Project planner	12	131.92	1583.059
	Planning manager	4	211.07	844.298
	Executive	4	452.57	1810.280
Joint venture partners provide feedback to the LNG project operator	Project planner	20	131.92	2638.432
The operator formulates a response to the Government, explaining how the project will meet its obligations to the domestic market	Project planner	37.5	131.92	4947.060
	Planning manager	4	211.07	844.298
The operator circulates submission to joint venture partners	Project planner	1	131.92	131.922
Joint venture partners assess the response, and determine if changes are required	Planning manager	12	211.07	2532.895
	Executive	4	452.57	1810.280
LNG project operator amends the response as per requests from individual joint venture partners	Project planner	7.5	131.92	989.412
	Planning manager	1	211.07	211.075
Joint venture partners reassess and approves the response	Planning manager	8	211.07	1688.596
	Executive	2	452.57	905.140
LNG project operator submits the response	Project planner	1	131.92	131.922
The Government assesses the response, and issues a final permission	No cost to industry			
Total				**$ 21,279.74**

Given the current state of the LNG export market in Australia, the model assumes that:

- A Minister's declaration of intent to make a determination would affect 10 LNG export projects.[28]
- The Minister's determination to invoke export controls would affect at most three export projects (i.e. at most three projects would be in net deficit, and would be granted a provisional license for a quantity smaller than the exporter had planned on).
- The ADGSM decision making and licensing process would occur, at most, once a year.

Taking these assumptions into account, Table 5 outlines the estimated total annual cost to industry.

Table 5: Total annual regulatory cost to industry[29]

ADGSM period	Number of impacted LNG projects	Cost per project	Total cost
Declaration	10	$ 11,580.55	$ 115,805.51
Assessment of shortfall	N/A - During this period, the only work is conducted by Government		
Determination	3	$ 21,279.74	$ 63,839.23
Total			$ 179,644.74

Additional assumptions and methodology

Overarching assumptions and caveats

- The costing model incorporates conservative assumptions with the intent to avoid underestimating the ADGSM's regulatory cost to business.
- The cost 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 (see Table 2) and Minister's declaration (see Table 4) points of the ADGSM.
- The model assumes that all LNG projects would treat the ADGSM in a similar way. This allows the model to calculate the cost for each project, and then multiply it by the 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[30]. Instead, it uses the job descriptions and wages in the 2016 Hays Salary Guide[31] for the "Oil and Gas" industry. OBPR standard wage rate assumptions are obtained from ABS data, however these ABS sources are not sufficiently detailed for the purpose of this analysis.

The Hays Salary Guide provided a range of yearly wages for a given position and state. For example, a Maintenance Supervisor could annually expect to earn between $135,000 and $180,000 in Western Australia, whereas the equivalent worker in Queensland would earn between $130,000 and $190,000. There were several steps in the process to calculate the hourly wage rates used in Table 2 and Table 4.

[28] According to APPEA, Australia currently has seven operating projects, and three more planned.
[29] Note: For the ADGSM period "Day 61 to 105", the only LNG exporters that would be affected are those with a net draw-down on domestic supply.
[30] Department of the Prime Minister and Cabinet, February 2017, *Regulatory burden measurement framework guidance note*
[31] Hays, June 2016,*The 2016 Hays Salary Guide*

First, the average yearly wage rates were calculated by taking the average of the maximum wage for the equivalent job in Queensland and Western Australia. Using the Maintenance Supervisor example above, the average yearly wage was calculated to be:

$$\frac{180{,}000 + 190{,}000}{2} = 185{,}000.$$

The average of Queensland and Western Australia was used because most LNG export projects operate from those states. The maximum was chosen in order not to underestimate the labour costs.

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). Finally, the model assumed an average working week of 38 hours, and that the employee would work 48 weeks in a year. The hourly wage for the Maintenance supervisor example used was therefore calculated to be:

$$\frac{185{,}000 \times 1.7538 \times 48}{38 \times 48} = \$177.49.$$

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. To estimate the yearly salary of an executive in the gas industry, this RIS took the average value of the Executive Incentive Plan for Woodside executives that held their position for the entire 2015-16 financial year. To estimate the hourly wage, this RIS assumed that executives worked for 50 hours each week, for 48 weeks in a year. The model did not add an additional loading for on-costs for the executive wages, because their remuneration package was comprehensive. It should be noted that this is a rough approximation only, and detailed information on executive pay within an industry is difficult to source.

Table 6 summarises the hourly wages used in the costing model.

Table 6: Wage rates used to calculate the regulatory costs

Hays Salary Guide description			RIS description	
Title	WA yearly wage ($'000s)	QLD yearly wage ($'000s)	Title	Labour rate ($/hr)
Planner	120-160	90-115	Project planner	131.92
Planning manager	170-220	170-220	Planning manager	211.07
Woodside average "executive incentive plan"	1086		Executive	452.57

Exclusions

The following costs were not included in the costing model

- Set-up and record-keeping costs

  The model assumes that exporters can prepare applications using existing data (e.g. production and export data, use of third party gas), 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. The mechanism is not designed to have a continuous submissions process.
- Costs of delay

  The costing model 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 establishing a new licencing framework, and of the government's internal assessment of an export application are outside the scope of the Regulatory Burden Measurement Framework, and have not been quantified.