REVIEW

Australian Energy Market Commission

STAGE 1 DRAFT REPORT

East Coast Wholesale Gas Market and Pipeline Frameworks Review

7 May 2015

Submissions due 1 June 2015. Reference: GPR0003
Stage 1 Draft Report

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Reference: GPR0003

Citation

AEMC 2015, East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 1 Draft Report, 7 May 2015, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive summary

The eastern Australian gas market is experiencing a period of significant growth and change, as conventional gas reserves decline, unconventional gas resources become increasingly important and the influence of international prices trends increase. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows. These factors are resulting in a renewed focus on market development and gas supply chain efficiency.

Against this background, the COAG Energy Council has requested that the Australian Energy Market Commission (AEMC or "Commission") review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia ("the East Coast Review"). The review will consider the role and objectives of the existing markets on the east coast in light of the changing market dynamics and set out a road map for their continued development. The Council has developed a Vision for gas market development and a Gas Market Development Plan which will guide the scope of this review.

The Council, at the request of the Victorian Government, has also asked the AEMC to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian Declared Wholesale Gas Market ("the DWGM Review"). At this stage we are incorporating analysis of the DWGM within the East Coast Review but during the second half of this year the DWGM Review will form its own workstream.

The focus of the reviews is therefore the means of exchange for gas: how physical and financial transactions take place between buyers and sellers. Although providing important context for the reviews, issues relating to gas production or levels of competition in the production sector largely fall outside of the AEMC's remit and are being considered by other bodies, which we intend to work and consult with closely given the complementarity of the analysis. In particular, the ACCC has been tasked with undertaking an inquiry into Eastern and Southern Australian wholesale gas prices.

The East Coast Review has been structured over two stages. Stage 1 will outline the overall direction for the east coast market development, including a factbase of current market outcomes and gap analysis between the Energy Council's Vision and the existing arrangements; and Stage 2 will more fully develop any necessary medium and long term adjustments required to implement the Vision, including the transition path required. This structure is designed to provide the Council with early and ongoing insight into the progress being made on the development and implementation of their reform agenda in this important area.

This report forms the AEMC’s Draft Stage 1 Report and contains our preliminary recommendations on the areas of focus for market reform, as well as market enhancements and initiatives that can be progressed in the near term. Submissions on this draft report are requested no later than **1 June, 2015**.

Changing market dynamics and the need for reform

Natural gas has historically been used for a range of industrial, commercial and domestic applications in eastern Australia. Large industrial use makes up the largest share of total gas demand in eastern Australia overall, accounting for 43 per cent of demand in 2012. Gas-powered generation is responsible for approximately one-third of demand, most of which is base load generation in Queensland and South Australia. Residential and commercial demand makes up a relatively small amount of demand in all states besides Victoria (and to a lesser extent, New South Wales), where it comprises over half of total demand.[1]

In an emerging market, with a handful of suppliers and customers, remote production facilities and pipelines had little alternative use if a buyer was to terminate its agreement to purchase the output of those assets. Long-term contracts were therefore implemented to reduce the risks and costs for both sellers and buyers of gas. In a small, stable market where transactions occurred infrequently, finding counterparties and undertaking negotiations was relatively straightforward.

The development of the LNG industry, combined with the growing maturity of the east coast market, is expected to fundamentally alter these market dynamics. While bilateral contracts are likely to remain a fixture of the east coast markets in the future, industry participants are also likely to require more flexible and sophisticated mechanisms to manage their gas portfolios. However, in the current environment a number of large users have reportedly found it difficult to find producers that are willing to enter into new long-term contracts, or contracts of sufficient length to meet their commercial needs and support investment. Concerns have also been raised by some users about the prices payable under new contracts.

The current facilitated markets in eastern Australia (the DWGM, the Short Term Trading Market (STTM) hubs and the Wallumbilla Gas Supply Hub) were intended to provide additional market options to complement the trade of wholesale gas through bilateral contracts and to allow greater transparency and improved price discovery.

However, it is not clear the DWGM and the STTM are meeting this objective or are likely to provide the flexibility required under the changed market dynamic. In particular, the requirement for all gas in these markets to be traded through them, despite the vast majority of transactions occurring through bilateral contracts outside of the markets, imposes additional direct and indirect costs on shippers. The markets can also expose participants to a number of price risks, for instance as a result of deviating from their scheduled positions, some of which may be difficult or impossible to manage.

A drawback of the prevalence of bilateral contracting for gas is that little price information is publicly available. This lack of transparency can impede the price discovery process. This is currently a particular concern to users as the market transitions to prices driven by the ability to export gas, and consequently influenced by international LNG prices.

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1 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 38.

The facilitated markets are however only part of the changing dynamic. There are substantial inter-linkages between transportation arrangements for gas and the facilitated markets for trading gas at demand and production centres. The full benefits of any further development of the markets are unlikely to be realised if gas cannot flow to where it is most highly valued.

Gas transportation arrangements on the east coast are characterised by a marked difference between those used in Victoria and those applying elsewhere. Under the Victorian arrangements, market outcomes in the DWGM determine the use of the pipeline system on a daily basis. Elsewhere, pipeline owners enter into bilateral contracts with their customers to allocate pipeline capacity, generally over long periods.

Bilateral contracting for gas transportation has facilitated significant new investment, with the Australian Pipelines and Gas Association (APGA) reporting that its members have built over $2.2 billion of new infrastructure providing 4000km of coverage across a large number of new gas transmission pipelines since 2000.[2] However, the significant increases in demand and the volatility of flows likely to be experienced on the transmission network in the future will test the flexibility of the current arrangements. As an example, the outage of a single LNG facility could lead to the redirection of gas equivalent to a significant proportion of total domestic demand. There are concerns that, under such circumstances, difficulties in reallocating rights to use pipelines will impede the ability of the market to reach an efficient outcome.

Directions for stage 2 and the treatment of medium to long term issues

The market and regulatory frameworks impacting Australia's gas markets have evolved in a somewhat piecemeal manner since the development of the initial gas access regime in the 1990's. Consequently, fully understanding the issues and then developing and assessing potential solutions is likely to require detailed analysis and consultation with industry.

As discussed, Stage 2 of the review is intended to allow for the development of any medium and long term adjustments necessary to implement the Vision. Our current view is that many of the issues identified to date are likely to fall into this category. In most cases, the ability to identify any useful incremental changes is likely to be limited. Progressing these issues first requires the long term roadmap for market development to be defined but we believe there will be some key areas of focus which are as follows:

- There appears to be a strong case for **redesigning the STTM**. The market is trying to achieve multiple objectives and, as a result, is complex and costly. We intend to consider whether it would be possible to simplify the design, which most likely will be based around a balancing market. We will consider the interaction with commodity trading at current and potential GSH locations. There may be merit in trialling a simplified market design at Brisbane and we have made a recommendation in relation to this in section 3.4.2.

2 APGA, Discussion Paper submission, p. 4.

- Similarly, we also intend to **reconsider the design of the DWGM**, to establish whether energy prices can be separated from balancing and uplift charges. In doing so, we will consider the potential for harmonising the balancing element of the market with the design of the STTM and the commodity element with the GSH.
- As part of this work, we will examine the potential to **introduce capacity rights to the DWGM**, with the objective of better facilitating market-led investment in network expansion. Allowing participants to signal the need for capacity augmentation would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it.
- We intend to consult with industry to **develop a long term strategy for the location of facilitated markets**. We will work closely with AEMO as it develops a conceptual design of a potential Gas Supply Hub at Moomba. We will consider how and when such a design might best fit into the wider east coast framework, including an assessment of the likely effect on liquidity in the broader market. This will be informed by the more detailed STTM and DWGM market design work, and will also consider broader questions, such as whether trade should be at specific physical location or at "virtual" points encompassing parts or all of the pipeline network.
- We note that AEMO is also progressing a workstream to **further develop the Wallumbilla GSH**, including investigating the potential for the provision of hub services. There is likely to be merit in complementing the technical work being conducted by AEMO by investigating the effects on the competitive landscape for the provision of hub services as part of Stage 2 of this review (including the possible need for economic regulation).
- A major element of the Stage 2 work will be to investigate and **consider potential measures to better facilitate pipeline capacity trading**. Building on our recommendation in this report to consider the extent to which the current Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change is likely to address the issue, we also intend to examine and potentially draw on approaches to this issue used in international markets in Europe and North America (to the extent that they might be applicable to Australian circumstances). Doing so will require us to examine the current barriers to secondary capacity trading, such as the way in which point to point rights are specified, and to consider the implications of any potential solutions on the broader gas access regime.
- Finally, we intend to **consider the strategic direction for information provision, including the Bulletin Board**. We will assess whether the coverage, timeliness and accuracy of information can be improved and, if so, whether the benefits of any informational improvements are likely to exceed the costs. We also intend to consider the broader institutional issues involved, including the appropriate roles for private providers and governments in information provision.

Issues that can be progressed in the shorter term

The Commission has given consideration to a number of issues that can be progressed over the short-term to assist the facilitated markets and pipeline frameworks to better achieve the National Gas Objective (NGO). These include:

- improving price transparency through either a survey-based gas price index and/or aggregating existing publicly available information;
- establishing the Bulletin Board as a "one-stop-shop" for all gas market data, including enhancing compliance;
- assessing the degree to which additional informational gaps fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and could be addressed under that process;
- establishing a technical working group to begin analysis on the potential simplification of the STTM design with the goal of transitioning these markets to a more focussed balancing market design;
- harmonising the start time of the "gas day," which currently varies across jurisdictions; and
- removing the limitation in the National Gas Law on who can submit DWGM rule changes.

The Commission is of the view that these "no-regrets" measures can be implemented without undermining the second stage of our work to develop the medium and long term adjustments required in the east coast markets and pipeline frameworks to implement the Energy Council's Vision.

Improving price transparency

While some information on wholesale gas prices is available in the market, greater transparency may be required as a transitional measure until there is an efficient reference price for market participants to refer to. We would be interested in receiving feedback from stakeholders on two potential options to achieve this:

1. Developing a survey-based gas price index for short, medium and longer-term contracts (eg six months, three years and five years) with basic terms and conditions and supply from the major delivery points (ie Wallumbilla, Moomba, Longford, Port Campbell and Yolla).[3] We would like to get a better understanding of whether market participants consider that there would be value in this option and, if so, what the impediments to its development may be, how it could be conducted and who should be responsible for conducting it.
2. Aggregating existing publicly available information and anecdotal reports on gas prices[4] into a monthly, quarterly or bi-annual report and publishing this on the

3 For example, the contracts could be assumed to provide for the firm supply of gas, have a 100 per cent take or pay provision, a 100 per cent load factor, no make-up gas provisions and no ability to vary contract quantities, a CPI price escalation mechanism and no price review clause.

4 For example, ASX announcements, company reports and industry publications, such as EnergyQuarterly, which contain estimates of gas prices realised by producers and anecdotal reports of the new contract prices.

Bulletin Board. Such a report could form part of an existing report (eg the Gas Statement of Opportunities, the AER's State of the Energy Market or the AER's Weekly Gas Market Report) or be developed as a separate stand-alone report. Again, we would be interested in getting stakeholders' views on the value of such a report to market participants and policy makers, and who would be best placed to prepare it.

It is important to note that with both options, we are not proposing an approach which involves mandating the disclosure of confidential information. While such disclosure would increase transparency, it is unclear how much value the market would derive from this information given the prices payable under these contracts reflect the value of all the terms and conditions of supply and not simply the value of gas.

We are also not suggesting that increased transparency alone is the desired outcome. However, increasing the ease with which all market participants, particularly users, can access key information that is critical to informing the development of pricing expectations will lower overall search costs and is likely to be in the long term interests of consumers.

Bulletin Board "one-stop shop"

It is clear that the informational sources on the eastern Australian gas market are fragmented and there could be value in establishing the Bulletin Board as a "one-stop shop" for market-based information. We are therefore considering changes that could be made to the Bulletin Board within the confines of the existing reporting framework to make it a more comprehensive source of information, further improve its usability and functionality and improve the reliability of the information provided.

Our preliminary thoughts on the changes that could be made to the Bulletin Board to increase its scope and improve its usability and functionality are outlined in Chapter 3 and include information on prices from the facilitated markets, planning and forecast information, increasing the scope of transportation capacity listings, inclusion of transportation charges and better functionality and layout suggestions. There may be other relatively simple improvements that can be made to the Bulletin Board that would not require a rule change and we would welcome hearing stakeholders' views on this before we suggest that further work be carried out in this area.

If the Bulletin Board is to become a "one-stop shop" then market participants will also need to have greater confidence in the accuracy and timeliness of the information that Bulletin Board facilities are providing. We are also therefore suggesting a greater focus on Bulletin Board compliance and enforcement processes.

Addressing additional information gaps

While the starting point for the Commission's assessment of the COAG Energy Council proposed Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change will be the COAG Energy Council's rule change proposal , we also intend to consider whether there are any other informational gaps that fall within the scope of the proposed rule change that could also be dealt with at this time. This would potentially include suggestions made by stakeholders for information on storage facilities including daily volumes, data on linepack, as well as further improvements be made to the medium-term capacity outlook information that Bulletin Board facilities are required to provide to AEMO.

STTM simplification

The Energy Council's Vision clearly outlines a desire for the development of an efficient reference price. Given its current design, delivery of an efficient reference price is unlikely to be a realistic expectation of the STTMs, given the difficulties of developing any significant volume of commodity trading at points so remote from production. While there are still a number of questions that need to be answered in Stage 2 of the review about the number, location and design of various market mechanisms, it appears inevitable that the STTM model must evolve. Stakeholder submissions also support the view that the STTM is overly complicated for the purpose it is currently serving and may be imposing unnecessary transaction costs on market participants.

We are therefore suggesting the formation of a technical working group led by the AEMC and including AEMO, market participants and others as appropriate that will be tasked with scoping how to transition the STTM from its current design to one focussed more specifically on balancing. The group will provide their assessment back to the AEMC to be considered as part of our Stage 2 recommendations on the broader market design framework.

Harmonising the gas day start times

Gas days currently start at differing times across the east coast.[5] Harmonising gas day start times may remove some of the complexity for parties that operate across multiple markets and assist the process of increasing the interoperability across all the facilitated markets. This would be likely to reduce transaction costs, and could therefore promote the NGO.

Given the widespread support shown for such a change to-date through submissions to the Discussion Paper, the final Stage 1 recommendations of this review could include a rule change that the Energy Council could submit to align gas day start times. We would be interested in the views of stakeholders regarding the practicalities of implementing such a change, in particular whether gas day start times should be harmonised across gas markets alone (and, if so, what time should be selected and why), or whether this harmonisation should also include the electricity market (ie aligning the gas day start times with the 4.00am day start time in the National Electricity Market). The AEMC is also interested to hear views on any costs that may accompany this change, for example the amendment of existing bilateral contracts and the recalibration of metering systems.

DWGM rule changes

Section 295(3) of the NGL provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[6]

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5 6.00am in Victoria, 6.30am at the Sydney and Adelaide STTM hubs, and 8.00am at the Brisbane STTM hub and Wallumbilla supply hub.

6 Victoria is currently the only adoptive jurisdiction.

We note that this restriction was raised in both the 2013 Victorian Gas Market Taskforce review and the 2013 AEMC Gas Market Scoping study. In both reviews, stakeholders expressed concerns with the process of engaging with AEMO prior to a rule change being submitted. It was suggested that this represents a barrier for smaller market participants and potential new entrants to influence market development.

To address these issues, we recommend that the restriction be removed. This would mean that any party would be able to propose rule changes applying to the DWGM, in manner consistent with the arrangements applying to the STTM, as well as those applying to the electricity sector through the National Electricity Rules.

Contents

1 Introduction

1.1 Context for the review

The eastern Australian gas market is experiencing a period of significant growth and change, as conventional gas reserves decline, unconventional gas resources become increasingly important and the influence of international prices trends increase. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows. These factors are resulting in a renewed focus on market development and gas supply chain efficiency.

Against this background, the COAG Energy Council has requested that the Australian Energy Market Commission (AEMC or "Commission") review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia ("the East Coast Review"). The review will consider the role and objectives of the existing markets on the east coast in light of the changing market dynamics and to set out a road map for their continued development.[7]

The Council, at the request of the Victorian Government, has also asked the AEMC to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian Declared Wholesale Gas Market ("the DWGM Review").[8]

The focus of the reviews is therefore the means of exchange for gas: how physical and financial transactions take place between buyers and sellers. Although providing important context for the reviews, issues relating to gas production or levels of competition in the production sector largely fall outside of the AEMC's remit and are being considered by other bodies, which we intend to work and consult with.[9]

1.1.1 Gas markets and transportation are interlinked

The terms of reference for both reviews recognise the inter-linkages between transportation arrangements for gas and the facilitated markets for trading gas at demand and production centres. Accordingly, much of the Commission's work thus far has been to consider this interaction and to understand how transportation arrangements and the facilitated markets can best support the efficient allocation of gas. The full benefits of any further development of the markets are unlikely to be realised if gas cannot flow to where it is most highly valued.

Gas transportation arrangements on the east coast are characterised by a marked difference between those used in Victoria and those applying elsewhere. Under the Victorian arrangements, market outcomes in the DWGM determine the use of the

7 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, p. 1.

8 See: COAG Energy Council and Victorian Government, *Review of the Victorian Declared Wholesale Gas Market*, Terms of Reference, 4 March 2015.

9 In particular, on 8 April 2015, the ACCC was tasked with undertaking an inquiry into Eastern and Southern Australian wholesale gas prices. In addition, on 14 April 2015, the Australian Government released its *Domestic Gas Strategy* on unconventional gas resources.

pipeline system on a daily basis. Elsewhere, pipeline owners enter into bilateral contracts with their customers ("shippers") to allocate pipeline capacity, generally over long periods.

Through its direct linkage to the DWGM, the focus of the Victorian arrangements is therefore to promote the efficient use of the system in the short-term. However, the lack of firm capacity rights in the Declared Transmission System (DTS) has led to well-documented concerns with investment outcomes over the long-term.[10]

In contrast, bilateral contracting for gas transportation has facilitated significant new investment, with the Australian Pipelines and Gas Association (APGA) reporting that its members have built over $2.2 billion of new infrastructure providing 4000km of coverage across a large number of new gas transmission pipelines since 2000.[11] Work previously undertaken for the AEMC highlighted general acceptance that these arrangements have delivered timely and efficient investment.[12]

However, the significant increases in demand and the volatility of flows likely to be experienced on the transmission network in the future will test the flexibility of the current arrangements. As an example, the outage of a single LNG facility could lead to the redirection of gas equivalent to a significant proportion of total domestic demand. There are concerns that, under such circumstances, difficulties in reallocating rights to use pipelines will impede the ability of the market to reach an efficient outcome.

Consequently, a key focus of the reviews will be to consider the extent to which changes to the gas transportation arrangements are required to enhance the efficiency of investment over the long-term in Victoria and to increase the flexibility of the arrangements elsewhere to promote the efficient usage of the system in the short-term.

1.1.2 The purpose and effectiveness of facilitated markets

As highlighted in the terms of reference, the facilitated markets in eastern Australia (the DWGM, the Short Term Trading Market (STTM) hubs and the Wallumbilla Gas Supply Hub) are not intended to replace the trade of wholesale gas through bilateral contracts, but rather provide additional market options which can lead to greater transparency and price discovery.[13]

However, it is not clear that the mandatory nature of the DWGM and the STTM is consistent with this objective. The requirement for all gas in these markets to be traded through them, despite the vast majority of transactions occurring through bilateral contracts outside of the markets, imposes additional direct and indirect costs on shippers. Participants are required to pay market fees on all gas flowed, irrespective of whether this is traded through the market to another party or not. The markets can also expose participants to a number of price risks, for instance as a result of deviating from their scheduled positions, some of which may be difficult or impossible to manage.

10 See, for instance: Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, pp. 40-41.

11 APGA, Discussion Paper submission, p. 4.

12 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 121.

13 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, p. 2.

A drawback of the prevalence of bilateral contracting for gas is that little price information is publicly available. This lack of transparency can impede the price discovery process.[14] This is currently a particular concern to users as the market transitions to prices driven by the ability to export gas, and consequently influenced by international LNG prices.

Another key focus of the reviews will therefore be to consider whether and how additional information might be provided to resolve these issues. While bilateral contracting is likely to remain the main mechanism for trading gas, the increasing maturity of the market, combined with more dynamic and volatile market conditions, are likely to drive a move towards an increasing amount of shorter term contracts.

Consequently, the introduction and development of reference prices that broadly reflect underlying supply and demand conditions would be of particular value in assisting market participants and users in commercial decision making. Similarly, simplification of the market designs and developing the conditions for hedging products could act to assist participants in managing risk.

Therefore, as detailed in the following sections, consideration of how the price discovery process might be enhanced to enable more informed and efficient decision making, and how market designs might better allow for participants to manage risk, in addition to examination of transportation arrangements, are specified in the terms of reference as the main areas of focus for the reviews.

1.2 The East Coast Gas Market and Pipeline Frameworks Review

As noted above, the East Coast Review is to consider the design, function and roles of facilitated gas markets and gas transportation arrangements in eastern Australia. The AEMC has been asked to develop specific actions that can be implemented to strengthen the structure and competitiveness of the eastern Australian market and make recommendations for immediate implementation, where possible.[15]

The terms of reference are provided in full at Appendix A, but broadly require the Commission to consider:

- the appropriate structure, type and number of facilitated markets on the east coast, including options to enhance transparency and price discovery, and reduce barriers to entry;
- opportunities to improve effective risk management, including through liquid and competitive wholesale spot and forward markets which provide tools to price and hedge risk; and
- changes to strengthen signals and incentives for efficient access to, use of, and investment in, pipeline capacity.

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14 Transparent pricing can support informed and efficient decisions about gas allocation, whereas decisions made on incomplete information can lead to inefficient trade, price divergence and inefficient resource allocation. Nevertheless, caution should be exercised when considering the disclosure of price information, as this can result in unintended consequences such as tacit price collusion. (See Chapter 8 for a more detailed discussion).

15 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, p. 1.

The East Coast Review will be structured over two stages:

- Stage 1 will outline the overall direction for the east coast market development, including a factbase of current market outcomes, a gap analysis between the COAG Energy Council's vision for Australia's future gas market (see Chapter 2) and the existing arrangements, and highlight any recommendations for immediate implementation; and
- Stage 2 will more fully develop any necessary medium and long-term adjustments required to implement the vision, including the transition path required.

1.3 The Review of the Victorian Declared Wholesale Gas Market

In light of the significant structural changes underway across east coast gas markets, the Victorian Government, with the agreement of the COAG Energy Council, has asked the AEMC to examine the DWGM specifically to assess whether reforms are required to enhance the liquidity, transparency and flexibility of the current arrangements.[16]

The full terms of reference for the DWGM Review are provided at Appendix B. In summary, the Commission is required to consider:

- the ability of market participants to manage price and volume risk in the DWGM and options to increase the effectiveness of risk management activities;
- whether market signals and incentives are providing for efficient use of and investment in pipeline capacity in the Declared Transmission System (DTS) which underpins the DWGM;
- trading between the DWGM and interconnected pipelines; and
- whether the DWGM arrangements continue to facilitate market entry and promote competition in upstream and downstream markets and how this could be improved.

In providing the terms of reference, the Victorian Government noted that there will be links between the recommendations and findings of the two reviews. Given these linkages the AEMC and the Victorian Government have agreed to combine the initial phase of the DWGM review with Stage 1 of the East Coast Review. As such, this report covers both reviews and includes the Commission's consideration of the issues arising in Victoria.

However, we are of the view that it will then be appropriate to consider options to address the issues identified in Stage 1 through discrete papers relevant to each review in the latter half of 2015. This will allow for a greater focus on the specific circumstances of the current markets. As such, we intend to release an Options Paper for the DWGM Review around August 2015, to coincide with the release of the East Coast Review Stage 2 Directions Paper. The timing of the two reviews is discussed in the next section.

16 Department of Economic Development, Jobs, Transport & Resources (Victorian Government), *Review of the Victorian Declared Wholesale Gas Market*, Terms of Reference, 4 March 2015, p. 1.

1.4 Review process

1.4.1 Consultation

This is the draft report for Stage 1 of the East Coast review and reflects the initial phase of the DWGM review. Stakeholders are invited to make submissions on this draft report before 1 June, 2015.

The Stage 1 Final Report will be provided to the Council in mid-2015.

Table 1.1 Indicative timing of the East Coast review and DWGM review

<table>
<tr><th>Due Date</th><th colspan="2">Milestone</th></tr>
<tr><td></td><td>East Coast Review</td><td>DWGM Review</td></tr>
<tr><td>February 2015</td><td colspan="2">Public forum seeking written submissions</td></tr>
<tr><td>April 2015</td><td colspan="2">Stage 1: Draft report for consultation</td></tr>
<tr><td>June 2015</td><td colspan="2">Stage 1: Final report</td></tr>
<tr><td>August 2015</td><td>Public Forum
Stage 2: Directions Paper</td><td>Public Forum
DWGM Options Paper</td></tr>
<tr><td>By early 2016</td><td>Stage 2: Draft report for consultation, including request for COAG response on any significant adjustments or longer term initiatives identified</td><td>Draft report for consultation, including request for Victorian Government response on any significant adjustments or longer term initiatives identified</td></tr>
<tr><td>Following response from COAG Energy Council and Victorian Government</td><td>Stage 2: Final report</td><td>DWGM Final report</td></tr>
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1.4.2 Advisory Group

As required by the terms of reference, the AEMC has established an Advisory Group that will operate across both reviews.

The Advisory Group will provide strategic advice and expertise to the Commission over the course of the review. The group meets periodically and is chaired by John Pierce, AEMC Chair. Advisory Group member organisations are listed in Table 1.2 below.

The Commission gratefully acknowledges the ongoing contribution made by the members of the Advisory Group.

Table 1.2 Advisory Group Members

Member	Role
Australian Energy Market Operator	Market operator
APA	Pipeline owner
Jemena	Pipeline owner and distributer
Australian Pipeline and Gas Association	Pipeline association
Santos	Producer
ExxonMobil	Producer
Origin Energy	Producer, retailer and gas fired power generator
AGL Energy	Producer, retailer and gas fired power generator
Energy Australia	Retailer and gas fired power generator
Simply Energy (GDF Suez Australian Energy)	Retailer (small)
QGC	LNG exporter
APLNG	LNG exporter
Visy Australia	Customer (large)
Energy Users Association of Australia	Customer representative (large)
St Vincent de Paul	Customer representative (small)

1.4.3 Public forum

On 25 February 2015, the AEMC held a Public Forum to inform the East Coast Review.

The forum provided an early opportunity for participants to discuss their views on the issues to be considered in the review, including those raised in the AEMC's brief discussion paper (released in advance of the forum to stimulate discussion).

The forum was attended by more than 70 representatives of gas pipeline owners, retailers, producers, large consumers, consumer groups, market regulatory bodies, other market participants and other experts covering a range of topics being considered in the review.

The presentations and discussion paper are available to download from the AEMC website.[17]

17 www.aemc.gov.au

Following the forum, interested stakeholders were invited to make written submissions to the AEMC on issues raised in the discussion paper and at the forum. We have drawn on these submissions in our analysis and throughout the report. A more comprehensive summary of submissions is provided as Appendix H.

1.5 Recent reviews into the east coast gas market and transportation arrangements

The current reviews follow a number of recent reviews and studies relating to the eastern Australian gas market. One of the aims of Stage 1 of the East Coast Review is to draw together the findings of this previous work.

Consistent themes have emerged across the reviews and are explored further in Chapters 4 to 8 of this report. Notably, most papers identified the need for a further strategic review into east coast gas market arrangements.

Appendix C summarises recommendations from the Scoping Study, the Eastern Australian Domestic Gas Market Study and the Gas Market Taskforce and the subsequent action taken to implement those recommendations. Many of the recommendations have been considered in this report, and will be further assessed in Stage 2 of the review.

1.5.1 The Scoping Study

The AEMC initiated the gas market scoping study in May 2013, in response to changes underway in Australia's eastern gas markets due to the emerging LNG export industry, and feedback from stakeholders through the strategic priorities review.[18]

The purpose of the Scoping Study was to:

- provide an overview of the changes underway in the eastern Australian gas market; and
- identify areas of potential improvement in the market and regulatory arrangements that may benefit from future market development work, prioritise their importance and identify who may be best placed to take the work forward.

The Scoping Study made 11 recommendations to improve the regulatory and market arrangements in the eastern Australian gas market. The highest priority identified by the Scoping Study was the need for a strategic review that would consider both:

- the direction that the eastern Australian gas markets should take over the next 10-15 years to transition to a more mature, well-functioning market; and
- the principles that should guide the development and design of facilitated gas markets in the future.

The Scoping Study also recommended a detailed review of the Short Term Trading Market (STTM) design and some elements of the Victorian Declared Wholesale Gas Market (DWGM) to determine whether improvements could be made that would better promote the NGO as a high priority.

18 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013.

1.5.2 Eastern Australian Domestic Gas Market Study

The Eastern Australian Domestic Gas Market Study was jointly prepared by the Commonwealth Department of Industry and the Bureau of Resource and Energy Economics (BREE).[19] The Study examined the components of the eastern gas markets: supply and demand, infrastructure, and that nature and role of trading mechanisms. The Study identified a range of policy options for reforming the eastern gas market, including:

- establish a forward gas market reform agenda;
- improve the commercial and regulatory environment for infrastructure; and
- improve market data and transparency.

Within these policy options, the Study suggested that the Energy Council should consider commissioning reviews covering wholesale gas market competition and the suitability of the pipeline carriage models.[20]

1.5.3 Gas Market Taskforce

The previous Victorian Government established the Victorian Gas Market Taskforce, which was chaired by the Hon. Peter Reith. The Taskforce was asked to provide policy options for "improving the operation and efficiency of the eastern Australian gas market, including ways to facilitate market transparency and transmission capability, and increasing gas supply to meet increasing demand at competitive prices".[21] The Taskforce's report was released in October 2013.

The Taskforce made 19 wide ranging recommendations related to the production, transportation and retail segments of the supply chain. The Taskforce also made recommendations for improvements to the wholesale markets and transmission pipelines. In particular, the Taskforce recommended that the Victorian Government request the AEMC to undertake a thorough review of the pipeline capacity, investment, planning and risk management mechanisms in the DWGM, with the objective of ensuring arrangements for access to the pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.[22]

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19 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014.

20 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 90.

21 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, p. 9.

22 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, p. 8.

1.5.4 ACCC inquiry

On 8 April 2015, the Australian Government directed the Australian Competition and Consumer Commission (ACCC) to commence an inquiry of wholesale gas prices in eastern and southern Australia. Under the terms of reference, matters to be taken into consideration in the inquiry include:[23]

- the availability and competitiveness of offers to supply gas and the competitiveness and transparency of gas prices;
- the competitiveness of, access to, and any restrictions on market structures for gas production, gas processing and gas transportation;
- the significance of barriers to entry into the upstream production sector;
- the existence of, or potential for, anti-competitive behaviour and the impact of such behaviour on purchasers of gas; and
- transaction costs, information transparency including gas supply contractual terms and conditions, and other factors influencing the competitiveness of the markets.

The inquiry is to be completed within 12 months.

1.5.5 Other reviews and input

The Productivity Commission recently released its research report *Examining Barriers to More Efficient Gas Markets*.[24] The report considers issues relating to exploration, production and transmission sectors. To assist with its analysis, the Productivity Commission developed a partial equilibrium model of the eastern Australian gas market.

On 30 March 2015, the Commission received a rule change request from the Energy Council to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board.[25] This is discussed further in Chapter 8.

We have also had regard to other recent reviews of the gas market prepared by the Energy Supply Association of Australia (ESAA), the Grattan Institute, AI Group and St Vincent de Paul (Victoria).[26]

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23 Australian Government, *Inquiry into competitiveness of the Wholesale Gas Industry*, Terms of Reference, 8 April 2015, p. 1.

24 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015.

25 Available from the COAG Energy Council's website: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/gtpct/

26 Energy Supply Association of Australia, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, Final Report, May 2013; Grattan Institute, *Getting Gas Right: Australia's Energy Challenge*, June 2013; AI Group, *Gas Market Transformations: Economic Consequences for the Manufacturing Sector*, July 2014; Alviss Consulting & Darach Energy Consulting Services, *Gas Wholesale Markets and Retail Competition in NSW and Victoria*, July 2012.

1.6 Submissions

Written submissions from interested stakeholders in response to this Draft Report on Stage 1 of the East Coast Wholesale Gas Market and Pipeline Frameworks Review must be lodged with the AEMC **no later than Monday, 1 June 2015 at 5.00pm**.

Submissions should refer to the AEMC project number "GPR0003" and be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au.

All submissions received during the course of this review will be published on the AEMC's website, subject to any claims of confidentiality.

1.7 Structure of this report

The next two chapters of this report are structured such that:

- Chapter 2 sets out the framework we intend to use to assess the effectiveness of existing market and regulatory arrangements, as well as any potential developments or enhancements; and
- Chapter 3 provides a summary of the key themes, draft findings and provisional recommendations.

The remaining chapters then present our analysis and findings as follows:

- Chapter 4: Transmission Pipeline Frameworks;
- Chapter 5: the Short Term Trading Market;
- Chapter 6: the Declared Wholesale Gas Market;
- Chapter 7: the Gas Supply Hub; and
- Chapter 8: Information Provision (including the Bulletin Board).

Finally, the report also contains a number of appendices, as follows:

- Appendix A: East Coast Review Terms of Reference;
- Appendix B: DWGM Review Terms of Reference;
- Appendix C: findings from previous reviews;
- Appendix D: regulatory framework for transmission pipelines;
- Appendix E: STTM operation;
- Appendix F: DWGM operation
- Appendix G: GSH operation; and
- Appendix H: summary of stakeholder submissions.

2 Assessment Framework

The purpose of this chapter is to outline the assessment framework that the Commission will use for both the East Coast and DWGM reviews. In providing advice to the Energy Council and Victorian Government, we will explain how our recommendations meet the assessment framework.

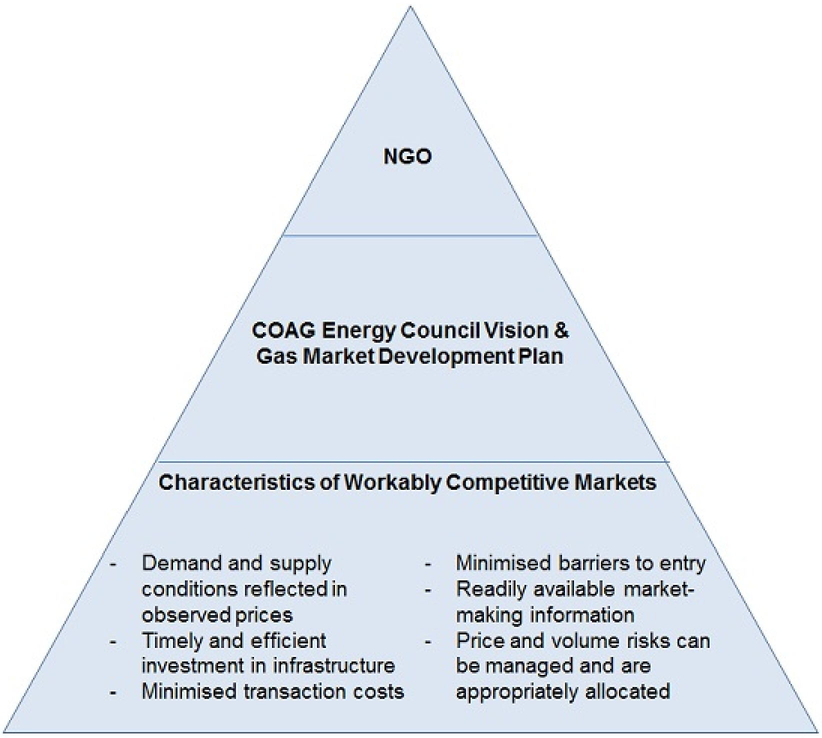
The assessment framework integrates the factors set out in both terms of reference that the AEMC must have regard to and articulates the relationship between them. High level principles that guide our market development and rule making work are also outlined, along with attributes that we consider are associated with a well-functioning, workably competitive gas market.

2.1 Assessment framework structure

In accordance with the terms of reference, the proposed assessment framework is structured so that the single overarching objective guiding the AEMC is the National Gas Objective (NGO).

In applying the NGO, the AEMC will have regard to the Energy Council's Vision and Gas Market Development Plan. The Vision is a statement agreed by the Commonwealth, state and territory energy ministers setting out the high level direction that gas market development should take in Australia for the NGO to be achieved. The Gas Market Development Plan is a program of work currently underway that supports the Vision.

Figure 2.1 Assessment framework



Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets and that are generally required for the NGO and Vision to be achieved. The relationship between the three aspects of the assessment framework is illustrated in Figure 2.1, and each is discussed below.

2.2 National Gas Objective

In accordance with the two terms of reference, the AEMC must have regard to the NGO in undertaking these reviews. The NGO is set out in section 23 of the National Gas Law and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The NGO is structured to encourage energy market development in a way that supports the:[27]

1. efficient allocation of natural gas and transportation services to market participants who value them the most, typically through price signals that reflect underlying costs;
2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs; and
3. ability of the market to readily adapt to changing supply and demand conditions over the long-term by achieving outcomes 1 and 2 over time.

The three limbs of efficiency described above are generally observable in a well-functioning, workably competitive market and together work to promote the long-term interests of consumers of natural gas.

In accordance with the NGO, the AEMC will take into account the long term interests of all consumers of natural gas throughout this review. The AEMC notes that there are numerous types of consumers of natural gas in the Australian economy, including: residential and commercial users; industrial and manufacturing users; gas fired generators; and LNG producers.

As with all rule changes and reviews, when applying the NGO we will have regard to the following set of high-level principles:

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently;
- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to mimic the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;
- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them; and

27 These three outcomes are commonly referred to as allocative, productive and dynamic efficiency, respectively.

- market and regulatory frameworks should be flexible and provide firms with a clear and consistent set of rules that allow them to independently develop business strategies and adjust to changes in the market. Frameworks should be resilient to changing supply and demand conditions, and patterns of flow, over the long-term.

We consider that these principles should guide the direction of any recommendations stemming from these reviews towards achieving the NGO.

2.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference, the AEMC must also have regard to the COAG Energy Council's Vision for Australia's future gas market and Gas Market Development Plan. Specifically, the Council has requested that this review consider the role and objectives of the facilitated gas markets on the east coast, and set out a road map for their continued development in order to meet the Council's Vision for Australia's future gas market, which is as follows:[28]

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The Vision is underpinned by four broad policy work streams and related outcomes:[29]

1. **Encouraging competitive supply:**
   (a) Improvements to the regulatory and investment environment so that gas supply is able to respond flexibly to changes in market conditions.
   (b) A "social licence" for onshore natural gas development achieved through inclusion, consultation, improving the availability and accessibility of factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.

2. **Enhancing transparency and price discovery**:
   (a) Increased flexibility and opportunity for trade in pipeline capacity.
   (b) Competitive retail markets that will provide customers with greater choice and large users with enhanced options for self-supply and shipment.
   (c) Provision of accurate and transparent market making information on pipeline and large storage facilities operations and capacity, upstream

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28 COAG Energy Council, *Australian Gas Market Vision*, December 2014, p. 1.

29 COAG Energy Council, *Australian Gas Market Vision*, December 2014, pp. 2-5. We note that these four work streams are also stated in the *Gas Market Development Plan*, available at: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

resources, and the actions of producers, export facilities, large consumers and traders.

3. **Improving risk management:**

   (a) Liquid and competitive wholesale spot and forward markets for gas that provide tools for participants to price and hedge risk.

   (b) Access to regional demand markets through more harmonised pipeline capacity contracting arrangements which are flexible, comparable, transparent on price, and non-discriminatory in terms of shippers' rights, in order to accommodate evolving market structures.

   (c) Harmonised market interfaces that enable participants to readily trade between locations and find opportunities for arbitrage and trade.

   (d) Identified development pathways to improve interconnectivity between supply and demand centres, and existing facilitated gas markets, which enable the enhanced trading of gas.

4. **Removing unnecessary regulatory barriers:**

   (a) Regulation of gas supply and infrastructure is appropriate and enables participants to pursue investment opportunities, in response to market signals, in an efficient and timely manner.

While stream 1, "encouraging competitive supply," is largely outside the scope of the AEMC's reviews, it provides necessary context to our more thorough consideration of issues relating to streams 2 to 4.

Overall, the Vision provides the Commission with a high level policy statement to guide its analysis through the review. It does this by setting out the broad direction that gas market development should take in order to meet the NGO. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the NGO – through increasing the efficiency of the gas market, for the long term benefit of consumers of natural gas services.

2.4 Characteristics of a well-functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets.[30] These are:[31]

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30 Application by Chime Communications Pty Ltd (No 2) [2009] ACompT 2, offers a "shorthand" description of workable competition which is "...a market with a sufficient number of firms (at least four or more), where there is no significant concentration, where all firms are constrained by their rivals from exercising any market power, where pricing is flexible, where barriers to entry and expansion are low, where there is no collusion, and where profit rates reflect risk and efficiency."

31 We note that these build on factors previously identified and used by the AEMC and others. See, for example: K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 86; and: ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, Final Report, May 2013, p. 37.

1. Demand and supply conditions reflected in prices: markets participants should have access to a credible reference price reflective of underlying supply and demand conditions that usefully aids commercial decision making.
2. Timely and efficient investment in infrastructure: efficient additions to, and expansions of, infrastructure enable supply to meet demand while minimising the cost of excess capacity.
3. Readily available market information: efficient outcomes are likely to be achieved when participants (current and potential) have access to clear, timely and accurate information about prices and factors driving prices, such as supply and demand conditions.
4. Price and volume risks can be managed and are appropriately allocated: participants being able to manage operational risks to delivery of physical gas while maintaining safe operating parameters, as well as being able to insure themselves adequately against financial risks.
5. Minimised barriers to entry: barriers to entry (and exit) can be a function of market structure, government regulation, industry-specific sunk costs or geography, and certain barriers have the potential to detract from the ability of markets to deliver efficient outcomes.
6. Minimised transaction costs: efficient transaction costs support timely and efficient investments in infrastructure and encourage competition.

These characteristics, if in place, would form a strong foundation for facilitated gas markets and transportation arrangements in eastern and southern Australia to promote the NGO and achieve the Energy Council's Vision.

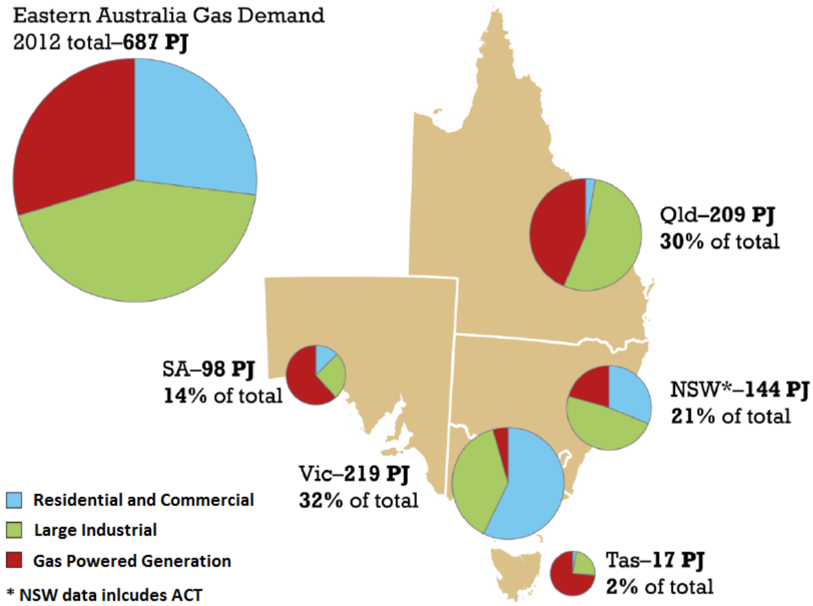
3 Summary of findings and recommendations

3.1 The east coast gas market is in the midst of change

Natural gas has historically been used for a range of industrial, commercial and domestic applications in eastern Australia. It is used for residential heating and cooking, as an input for electricity generation and to support a wide range of industrial and commercial processes to manufacture pulp and paper, metals, chemicals, stone, clay, glass and certain foods.

As shown in Figure 3.1 below, large industrial use makes up the largest share of total gas demand in eastern Australia overall, accounting for 43 per cent of demand in 2012. Gas-powered generation is responsible for approximately one-third of demand, most of which is base load generation in Queensland and South Australia. Residential and commercial demand makes up a relatively small amount of demand in all states besides Victoria (and to a lesser extent, New South Wales), where it comprises over half of total demand.[32]

Figure 3.1 Breakdown of domestic consumption of gas in eastern Australia, 2012



Source: Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 38, using data from the AEMO 2013 Gas Statement of Opportunities.

The gas market in eastern Australia is currently undergoing a significant transformation, and this is likely to have major implications on interactions between market participants and how transactions occur.

In an emerging market, with a handful of suppliers and customers, remote production facilities and pipelines had little alternative use if a buyer was to terminate its agreement to purchase the output of those assets. Long-term contracts were therefore implemented to reduce the risks and costs for both sellers and buyers of gas. In a small,

32 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 38.

stable market where transactions occurred infrequently, finding counterparties and undertaking negotiations was relatively straightforward.

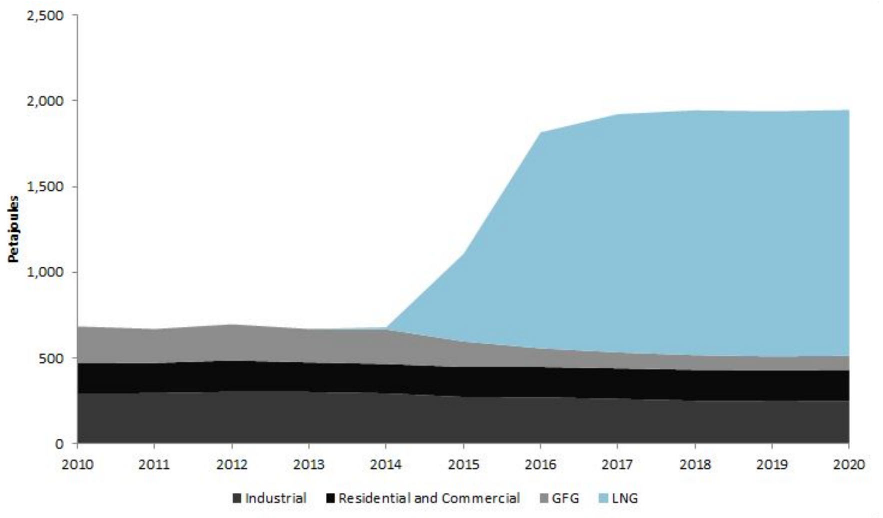
However, the development of the LNG industry, combined with the growing maturity of the east coast market, is expected to fundamentally alter these market dynamics. While bilateral contracts are likely to remain a fixture of the east coast markets in the future, industry participants are also likely to require more flexible and sophisticated mechanisms to manage their gas portfolios. These might, for instance, allow generators to purchase gas in the short-term to generate on a more "opportunistic" basis.

This chapter sets out the drivers of change in this market, the journey of market development to date and the case for continued development of the market into the future. The chapter also outlines the AEMC's Stage 1 findings and recommendations and sets the direction for Stage 2 of this East Coast Review and the DWGM Review.

3.1.1 LNG is creating opportunities for more short term trading of gas

In January 2015, the first LNG cargos were exported from Gladstone, with significant volumes of coal seam gas (CSG) coming online to meet the new demand from LNG. First exports represent a historic moment and the market has now entered a transitional period to a new supply/demand balance. The demand for gas in eastern Australia will increase substantially as the three LNG export projects ramp up to full production, as can be seen in Figure 3.2.

Figure 3.2 Demand for east coast gas is increasing to support LNG production

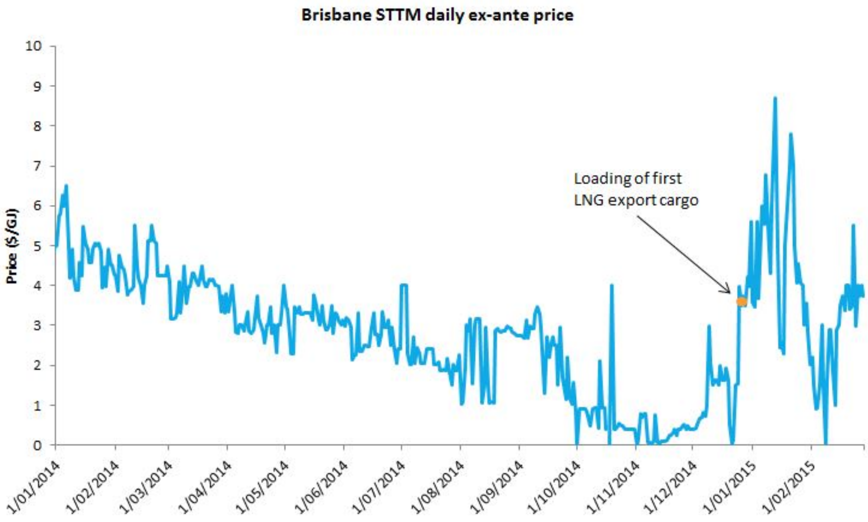


Source: AEMO, *National Gas Forecasting Report*, 2014.

Figure 3.3 shows the effect on ex ante prices at the Brisbane STTM hub of bringing the first LNG train online through 2014 and early 2015.[33]

33 STTM ex ante prices are largely determined by participants' imbalance volumes, and are susceptible to both a small volume of trades and small number of market participants. As such the STTM price does not reflect a true commodity price.

Figure 3.3 Brisbane ex ante STTM prices have been volatile as first LNG cargos were shipped



Source: AEMC analysis; AEMO.

The reduction in ex ante prices from the beginning of 2014 until late December reflected the need to bring 2,000 CSG wells progressively online to ensure sufficient gas was available to meet the requirements of the first LNG plant.[34] As the liquefaction of natural gas and loading of the first cargo took place, prices increased and exhibited greater volatility as excess gas in the market was used by the LNG plant.

Market conditions are expected to remain dynamic over the next 12 to 18 months as another five LNG trains are commissioned and ramped up to full production – potentially creating commercial opportunities for participants to engage in short term trading of gas as exporters seek to balance their cargo schedules.

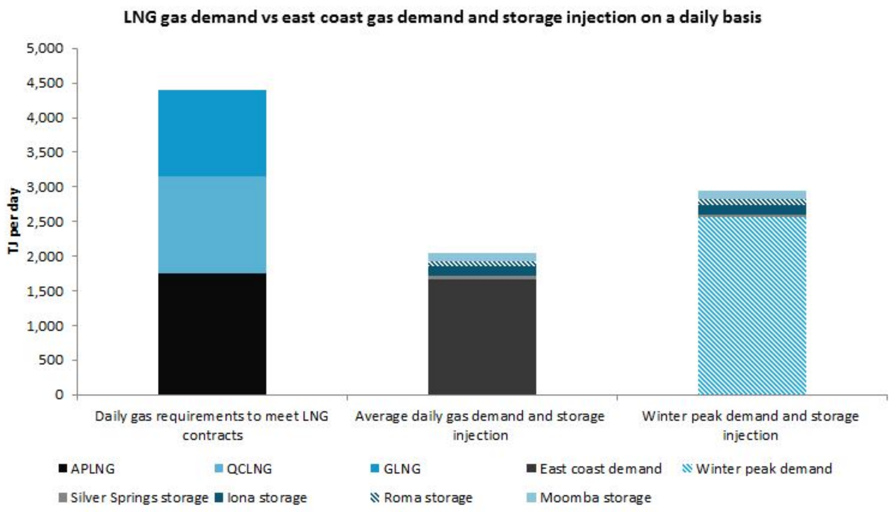
Once the LNG trains are fully operational they will consume around 4,400 TJ of natural gas per day on average to meet their contractual obligations, and more if the trains are run at maximum capacity. This compares to average daily consumption on the east coast of around 1,665 TJ per day, and to winter peak demand on the east coast of 2,560 TJ per day.[35]

As can be seen in Figure 3.4, the gas required for LNG production is over double domestic consumption and storage injection on a daily basis. If one of the LNG trains trips unexpectedly, and assuming an average turn down rate of 80 per cent for CSG wells, this would leave 125 to 174 TJ per day of gas to be absorbed by the domestic market, equivalent to 6 to 8.5 per cent of average daily gas demand and storage injection.

34 BG Group 2014, Press release: BG Group loads first LNG cargo from QCLNG project in Australia, accessed 25 March 2015, <http://www.bg-group.com/~/tiles/?tiletype=pressrelease&id=744>

35 EnergyQuest, *EnergyQuarterly*, March 2015 Report, pp. 69-75; AER Industry Statistics.

Figure 3.4 Daily gas demand from LNG is over double domestic market demand



Source: AEMC analysis; EnergyQuest; AGL; AEMO; Santos; AER.

The large amount of gas required for LNG exports compared to domestic consumption, combined with the inherent variability in supply from CSG, may stimulate the need for greater flexibility by participants to optimise their gas portfolios. A number of scenarios can be envisaged where the supply/demand balance in eastern Australia could shift quickly in response to LNG operations, including:

- during commissioning of the LNG trains;
- when the LNG trains shut down for maintenance;
- if an LNG train trips unexpectedly;
- if the capacity of the LNG export pipeline is reduced for unplanned maintenance; and/or
- if the productive capacity of the gas fields is reduced for unplanned maintenance.

Under each of these scenarios, flexibility to trade gas and pipeline capacity at short notice, as well as access gas storage, may be critical for the security of the gas system. This flexibility may also enable participants to maximise efficiency when balancing commercial gas portfolios and the market more broadly. An example of portfolio optimisation during commissioning of QCLNG Train 1 is discussed in Box 3.1.

Box 3.1 Commissioning of QCLNG Train 1

In the months leading up to the commissioning of QCLNG Train 1 and loading of the first cargo on 27 December 2014, prices at the Wallumbilla supply hub were as low as $0.20/GJ, with the volumes of trades ranging between 2,000 GJ and 40,000 GJ per day.[36]

Participants with flexible gas supply and pipeline capacity arrangements were able to take advantage of the short term price volatility that resulted. Origin Energy's activities over the second half of 2014 provide an insight into how gas portfolios can be optimised to take advantage of these commercial opportunities and support the efficient allocation of gas throughout the east coast market.

Origin was able to turn down production on its equity gas while purchasing 28 PJ of ramp gas.[37] This allowed the business to take advantage of the relatively cheap ramp gas to supply its customers, while preserving its equity gas for use at a later date. Origin was also able to monetise ramp gas through additional gas-fired generation and business sales.[38]

3.1.2 Gas prices are now linked to export markets

Unlike Western Australia and the Northern Territory, where LNG has been exported for a number of years, the east coast market has been insulated from international influences on domestic gas prices. Gas has historically competed against other fuel sources such as coal for use in electricity generation, with the abundance of low cost coal on the east coast effectively capping domestic gas prices.[39]

As the industry was developing it was common for bilateral gas supply agreements (GSAs) to be entered into for periods of 20 years or longer to underwrite the investments that producers, pipeline owners and users had to make in their assets.[40] Gas transportation agreements (GTAs) typically matched the terms of gas supply contracts. Most gas supply agreements contained take or pay clauses and prices were generally escalated in line with inflation annually, with provision for periodic reviews.[41]

In the past 15 years the outlook for the east coast gas market has changed considerably. Expected increases in gas-fired generation have not occurred due to the fall in electricity

36 AER Industry Statistics.

37 Ramp gas is the increased production from CSG wells in advance of increased demand from the LNG trains.

38 Origin Energy, 2015 Half year results announcement, 19 February 2015, p. 21.

39 AER, *State of the Energy Market 2008*, p. 243.

40 For instance, the 540 PJ gas supply agreement between AGL and QGC for 20 years in 2006 and a 12 year agreement between Santos and TRUenergy for 425 PJ of gas announced in 2002.

41 NERA, *The Gas Supply Chain in Eastern Australia*, A report to the Australian Energy Market Commission, March 2008, p. 27.

consumption and the removal of the carbon price, while six LNG trains with a combined capacity of over 1,500 PJ per annum will soon commence operations.[42]

The advent of LNG exports on the east coast is putting upward pressure on domestic gas prices due to the substantial increase in demand for gas. As the LNG projects represent such a large component of east coast gas demand, and the export contracts are linked to an international oil price, there has been a growing trend to link domestic gas contracts to oil.[43] The linkage of GSAs to international oil prices is a relatively new phenomenon for the domestic market and presents an unfamiliar risk for gas consumers to manage.

In recent times there have been concerns amongst some retailers and large industrial stakeholders that access to GSAs is becoming more difficult and more expensive as a result of this linkage. While some users have reported that they are unable to get responses to tenders for gas supplies extending beyond the next couple of years,[44] others have expressed a view that the inability to secure contracts is not linked to a shortage of gas, but a shortage of gas available at "legacy prices".[45]

As noted by the Productivity Commission recently:[46]

> “Reluctance to enter into supply commitments with gas users may be commercially rational behaviour in a highly uncertain market environment. Producers may be unable to charge prices in the eastern market that are high enough to compensate them for forgone export revenues and other costs of not fulfilling their export contracts... ”

This period of volatility in the market coincides with the expiry of many domestic long-term GSAs,[47] raising questions around the market's resilience to such significant changes. The uncertainty appears to be triggering moves to shorter-term contracts and is likely to drive new approaches to risk management (for instance, to manage oil price and exchange rate fluctuations). The need for such levels of flexibility was largely unforeseen at the time that the current market frameworks were developed.

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42 MDQ Consulting, *NSW Wholesale Gas Market Report*, February 2014, p. 37.

43 Since 2013, a number of ASX-listed entities, including Origin Energy, Lumo Energy and AGL, have announced domestic gas contracts linked to oil.

44 Alliance of Industry Associations, Discussion Paper submission, 2015, p. 6. (Alliance members include AI Group, Energy Users Association of Australia, Australian Aluminium Council, Australian Food and Grocery Council, Australian Steel Institute, Plastics and Chemicals Industries Association.)

45 Macquarie Research, *Australian East Coast Gas: a more orderly transition*, April 2015, p. 20.

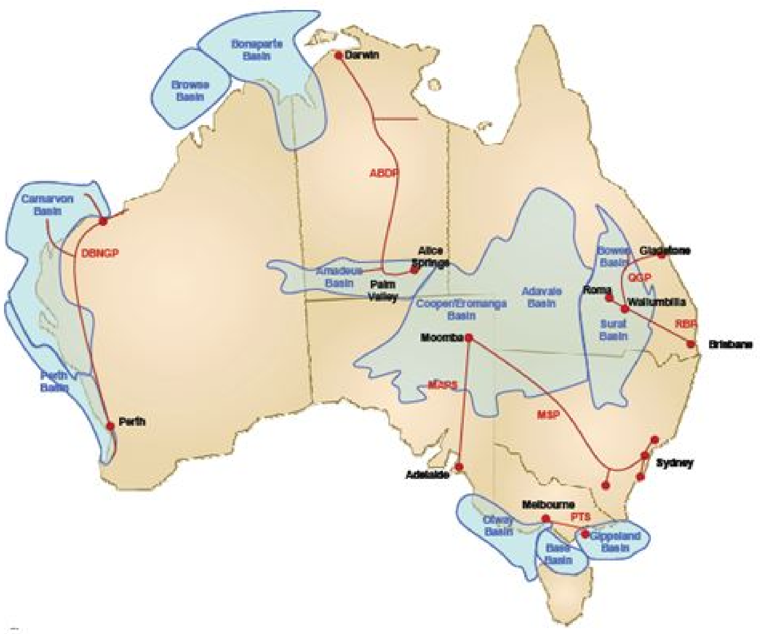
46 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 23.

47 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 12.

3.1.3 East coast gas market frameworks were developed for different market conditions

During the early years of the development of the natural gas industry in Australia, gas flowed from production sources directly to demand centres. On the east coast, production around Roma was used to supply Brisbane and Gladstone; production at Moomba supplied Adelaide and Sydney; and Victorian offshore gas fields supplied Melbourne. There was effectively no integration between the sources of supply and demand, as can be seen in Figure 3.5.

Figure 3.5 Australian gas supply and pipelines in 1990



Source: NERA Consulting, *Gas Pipeline Regulatory Framework*, A report for the AEMC, September 2008, p. 5.

It was against this background that COAG agreed to implement a number of recommendations made by the Industry Commission and the Independent Committee of Inquiry (Hilmer Review). These recommendations included that legislative and regulatory barriers to inter and intra-jurisdictional trade of gas be removed and that a new national framework for third party access to gas transmission pipelines be introduced. Based largely on the national access regime in Part IIIA of the *Trade Practices Act 1974* (TPA),[48] the Gas Pipeline Access Law and Gas Code were introduced in 1997.

A key element of the Code was the concept of a coverage test that could be applied to each individual pipeline to determine whether or not it should be covered by the access regime.

Where a pipeline was covered, requirements that have become to be known as "full regulation" were applied. Under these arrangements, the relevant pipeline operator was required to prepare an access arrangement and have the proposed price and non-price terms and conditions for reference service(s) approved by the relevant regulator. The pipeline operator and users were free to enter into a commercial agreement that

48 Now the *Competition and Consumer Act 2010* (CCA).

differed from those set out in the access arrangement, but if a dispute about access arose a dispute resolution body was required to give effect to the access arrangement provisions.

The reference tariff therefore represents a benchmark for the negotiations through which service providers enter into bilateral contracts with access seekers to allocate pipeline capacity, with this form of arrangement being known as "contract carriage."

The access regime was applied to transmission and distribution pipelines. Other facilities in the gas supply chain, such as storage and gas processing plants, were not included.

In 1999, the Victorian Government introduced the DWGM, a compulsory market allowing market participants to trade daily imbalances. The DWGM operates across the DTS, a covered pipeline system, which, at the time the DWGM was introduced, was isolated from other transmission pipelines. The market design chosen introduced a different form of carriage arrangement on the DTS – market carriage – where usage of the pipeline is determined by outcomes in the wholesale market.

A second phase of national reform of the gas market occurred between 2002 and 2008, following an independent review of the strategic direction for energy market reform that was chaired by Warwick R. Parer,[49] the Productivity Commission's 2003–04 review of the gas access regime[50] and the 2006 Expert Panel report on energy access pricing.[51]

These reforms established the current energy market governance arrangements, including the formation of the AEMC and AER and creation of the NGL and NGR. By consolidating the state-based regulatory regimes, these governance arrangements were designed to reduce regulatory burden and increase consistency with the electricity regulatory framework.[52] The new framework also introduced two further regulatory options into the gas access regime:

- "light regulation," which places greater emphasis on commercial negotiation and information disclosure than full regulation, but which retains provision for parties to have recourse to the dispute resolution mechanism if negotiations fail; and
- a 15 year coverage exemption for greenfield pipelines.

In 2005, the COAG Energy Council established the industry-led Gas Market Leaders Group (GMLG) to accelerate the development of the natural gas market. Following the GMLG's recommendations, the National Gas Services Bulletin Board (BB) and Gas Statement of Opportunities (GSOO) were implemented in 2008–09 to increase market transparency, while the STTM was introduced to provide a day-ahead market for trading gas between transmission and distribution pipelines and a balancing service. The STTM started at hubs in Adelaide and Sydney in September 2010, with a hub being established in Brisbane in December 2011.

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49 Parer, Warwick R., *Towards a Truly National and Efficient Energy Market*, 20 December 2002.

50 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004.

51 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

52 Parer, Warwick R., *Towards a Truly National and Efficient Energy Market*, 20 December 2002.

In December 2012, the Energy Council asked AEMO to develop the Wallumbilla Gas Supply Hub (GSH), the objective of which was to enhance transparency and reliability of gas supply by creating a voluntary market to provide a low-cost, flexible method to buy and sell gas. Wallumbilla was chosen for its proximity to significant gas supply and demand centres, and is a transit point situated at the intersection of three major pipelines.[53]

Over the period since the start of the reform process, the gas market environment has changed significantly. Many new pipelines have been constructed, most recently the LNG pipelines in Queensland and, prior to that, the Eastern Gas Pipeline, the SEA Gas Pipeline and QSNLink, amongst others. As a result, the market in eastern and southern Australia is now fully integrated, with transmission pipelines beginning to form an interconnected grid, as can be seen in Figure 3.6.

Figure 3.6 East coast gas supply and pipelines in 2014

Source: AEMO, *Gas Statement of Opportunities*, 2012 (amended to reflect the location of LNG facilities).

53 These pipelines are the Roma to Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

In comparison, and despite the ongoing reform and development process, the market and regulatory frameworks appear fragmented and disjointed. Today, on the east coast, there are:

- three different facilitated market designs (DWGM, STTM and GSH);
- two different pipeline carriage arrangements (contract carriage and market carriage); and
- four principal sets of pipeline regulatory arrangements (full regulation, light regulation, no regulation and 15 year coverage exemptions).

It is no longer clear that the objective underpinning the initial development of the access regime – to provide access to individual gas pipelines – remains relevant in the context of an interconnected network and the changing market dynamics discussed earlier in this chapter.

Against this background the Commission has considered whether the current frameworks remain fit for purpose and whether there are barriers that impede gas from flowing to its highest value use.

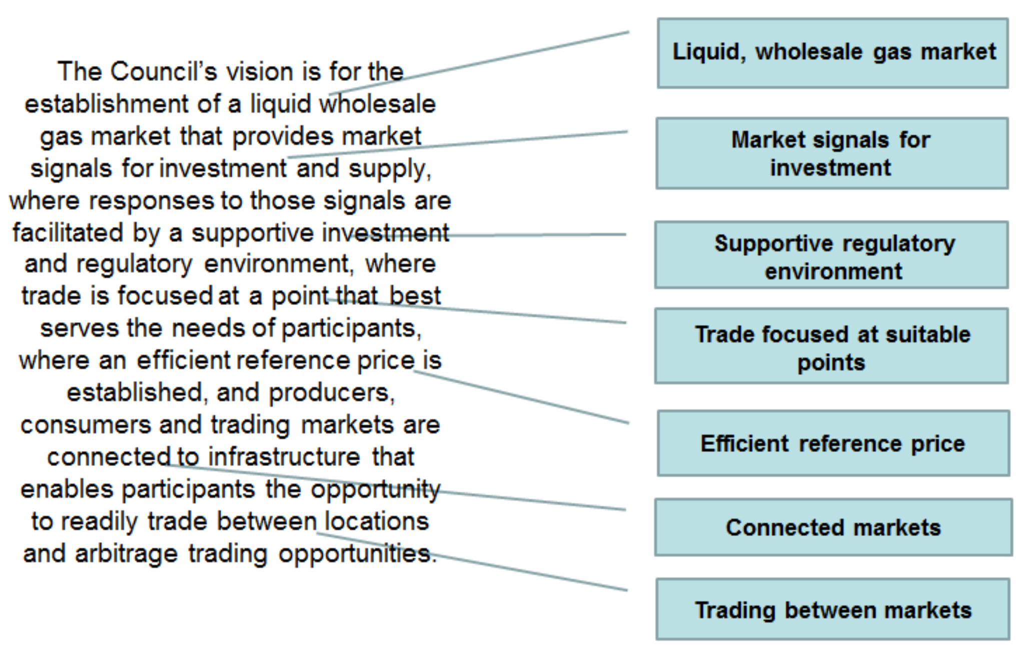
3.2 Assessment of existing market and pipeline frameworks

As discussed, the external environment within which the east coast market exists is shifting. There is likely to be a more dynamic supply and demand balance, patterns of gas flow will change and prices are likely to be more volatile and increasingly influenced by developments in international energy markets.

In recognition of this transformation, the COAG Energy Council released its Vision for the Australian gas market in December 2014, and tasked the AEMC with undertaking this review in order to assist the Council in realising it.

The Vision can be broken down into seven elements, as shown in Figure 3.7 below.

Figure 3.7 Key elements of the COAG Vision



In accordance with our assessment framework, we intend to use the Vision as a guide to the high level direction that gas market development should take in order for the NGO be achieved. This section therefore considers the extent to which the current market and pipeline frameworks are aligned with each element of the Vision.

3.2.1 Liquid, wholesale gas market

As discussed earlier in this report, gas has historically been traded between market participants on a bilateral basis, and this remains the predominant means of exchange today.

In Victoria and at the STTM hubs (Adelaide, Brisbane and Sydney), all gas has to be transacted through the relevant facilitated market (the DWGM and STTM, respectively). However, in practice, the vast majority of trades – between 80 per cent in Victoria and 95 per cent in Brisbane[54] – occur between the same entities. These transactions are occurring solely because of the compulsory nature of the market and are not adding value in terms of bringing together buyers and sellers to trade.

Nevertheless, the DWGM and STTM play a number of important roles. They have provided a largely effective and competitive gas balancing service, which supports retail competition. A number of participants, including new entrant retailers, have found them to be a useful way of initially entering the gas market before committing to bilateral gas supply and transportation agreements. We have also heard from large industrial users that the markets provide assistance in supplementing volumes secured through bilateral contracts.[55]

Although only operational for around a year, market participants are generally of the view that the Wallumbilla GSH provides a useful and low-cost platform for the commodity trading of gas. There have been between five and eight participants per month trading at the hub. However, volumes traded to date remain relatively small in the context of the wider market: the 2.9 TJ traded over the first 11 months represents approximately 1.1 per cent of total gas consumption in Queensland during 2014.[56]

It seems likely that the liquidity of the market at Wallumbilla is being impeded by physical limitations on flows, with trades split across three different locations (one for each of the three major pipelines at Wallumbilla). AEMO is currently undertaking work to consider how the three trading locations might be consolidated, with stakeholders generally being supportive of this process.[57]

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54 Further information is provided in Chapters 5 and 6.

55 Adelaide Brighton Cement Limited, Discussion Paper submission, p. 2; Qenos, Discussion Paper submission, p. 4.

56 Total gas consumption for Queensland in 2014 was estimated to be 266 PJ, see: EnergyQuest, *Energy Quarterly*, March 2015, Figure 44, p. 108.

57 APA, Discussion Paper submission, p. 18; Santos, Discussion Paper submission, p. 5; ESAA, Discussion Paper submission, p. 6; Origin Energy, Discussion Paper submission, p. 4; Lumo Energy, Discussion Paper submission, pp. 9-10.

3.2.2 Market signals for investment

In the last two decades, there has been significant investment undertaken in the gas market in eastern Australia. Production has increased markedly, with the recent investment in CSG production in Queensland and in the associated LNG export facilities currently having a transformative effect on the industry. There are concerns that rising prices are signalling the need for further supply and that this may not be occurring due to regulatory barriers. However, this issue is being considered by governments through processes outside of this review.[58]

In the pipeline sector, it is generally accepted that the contract carriage model has efficiently facilitated new investment. Bilateral contracting between users and pipeline developers has led to the construction of strategically important new pipelines, such as the Eastern Gas Pipeline, the SEAGas Pipeline and the QSNLink. Improvements are also being undertaken to allow for bi-directional flows on many major pipelines, such as the Moomba to Sydney Pipeline, the Moomba to Adelaide Pipeline System and the Roma to Brisbane Pipeline.[59] These developments will significantly enhance the ability of gas to flow to where it is most valued.

However, the market contract carriage model in Victoria does not appear to be similarly supportive of market-led investment in the DTS. Any privately funded augmentation of a shared DTS asset would be available for use by all market participants, and this appears to have deterred such investments.[60]

APA has told us that the current market driven investment to expand the northbound export capacity of the DTS was only made possible by the certainty given by having contracts for firm capacity in place on the interconnected contract carriage pipeline.[61] In practice, investment in the DTS has largely relied on the regulatory process, whereby expenditure is approved by the AER and its recovery is shared across users.

3.2.3 Supportive regulatory environment

The gas regulatory framework is underpinned by the access regime, supplemented by rules governing the facilitated markets and Gas Bulletin Board. The access regime applies only to pipelines and not to storage or gas processing facilities, and the Commission is keen to hear further views as to whether there is a case for a third party access regime being applied to such facilities.

Stakeholder submissions to date on the regulatory framework have expressed diverse views. A number of stakeholders consider that the framework is working as policy makers intended, with some suggesting that the coverage provisions have contributed

58 The Australian Government's Domestic Gas Strategy, released on 14 April 2015, is intended to inform discussions with state governments, who have primary responsibility for onshore gas development, on ways to address unnecessary barriers to bringing on new gas supply.

59 AEMO, *Gas Statement of Opportunities*, April 2015, pp. 2-3.

60 Gas Wholesale Consultative Forum, *Discussion Paper: GWCF 10-095-01 Investment AMDQ*, 5 August 2010.

61 APA, Discussion Paper submission, p. 14.

to the ability of pipeline owners and users to work together to expand pipeline capacity and meet market demand.[62]

However, other stakeholders have claimed that there are some gaps in the current arrangements, most notably associated with investment in the market carriage model and secondary capacity trading under contract carriage.

In addition to the difficulties associated with market-led investment in Victoria, APA, the owner of the system, has expressed strong concerns about the effectiveness and timeliness of the regulatory process in determining investment on the DTS.[63] In contrast, others, including the AER, have questioned the view that the regulated model of transmission investment in the DTS is deterring efficiency in the level and timing of investment.[64]

Outside of Victoria, the significant increases in demand and in the volatility of flows likely to be experienced on the pipeline network will test the flexibility of the current arrangements. While governments and industry have made progress in recent years, barriers remain to short-term and secondary trading of pipeline capacity.

Although questions have been raised in relation to the incentives on holders to release capacity if it would be more highly valued by another party, many of the barriers to capacity trading appear to relate to search and transactions costs. In particular, stakeholders have highlighted that, on a point-to-point pipeline with multiple injection and withdrawal points, defining capacity rights and system operation may be especially difficult.[65] This will naturally tend to inhibit the specification of fungible rights and liquid trading.

While continued industry-led initiatives are welcome, a question for this review will be whether any regulatory intervention is necessary to better facilitate capacity trading. To the extent that this would require placing regulatory obligations on currently uncovered pipelines, it is unclear whether this could be supported by the existing regulatory framework.

A further matter not contemplated under the current regulatory environment is the concept of Hub Services. As AEMO progresses its work plan to consider measures to increase liquidity at Wallumbilla, there is likely to be a need to consider the possible need for the economic regulation of Hub Services and, if necessary, how this would be accommodated in the regulatory regime.

3.2.4 Trade focussed at suitable points

The selection of Wallumbilla as the location for the Gas Supply Hub reflected its strategic location at the intersection of three major pipelines, close to significant sources of gas production and relatively proximate to major demand centres at Brisbane and

62 APGA, Discussion Paper submission, p. 41; APA, Discussion Paper submission, p. 3; Jemena, Discussion Paper submission, p. 1; Santos, Discussion Paper submission, p. 7.

63 APA, Discussion Paper submission, p. 12.

64 AER, Discussion Paper submission, pp. 3-4; Lumo Energy, Discussion Paper submission, pp. 12-13.

65 AGL, Discussion Paper submission, p. 6; EnergyAustralia, Discussion Paper submission, p. 3.

Gladstone. To the extent that it is possible to develop a liquid trading hub, Wallumbilla appears to be a suitable location.

The decision to introduce the STTM in Adelaide, Sydney and Brisbane was driven by their status as centres of demand, and the need for some form of balancing market in these locations appears clear.

However, it is less certain that developing any significant volume of commodity trading at the current STTM hubs is a realistic goal. It appears that such trade is more naturally undertaken at supply centres. In particular, the value of the Brisbane STTM has been questioned given its relatively lower and more predictable load profile, and the presence of the Wallumbilla GSH in close proximity.[66]

As a major centre of supply, Victoria would appear to be a suitable point for trading. However, it is not clear that the current design of the DWGM best facilitates trading between producers and retailers/users. We understand that most trade continues to be undertaken through bilateral contracts at the production facility. Consequently, while there appears to be a need to reconsider the design of the DWGM, this should be done in the context of providing a hub for commodity trading as well a balancing market.

Developing a strategic approach to the location of trading points would allow for a fully informed decision to be made on the merits of implementing a GSH at Moomba. While we see the merit in a GSH location at Moomba, given its status as a production centre linked to multiple pipelines, there is a need to consider how and when it might best fit into the wider east coast market. As noted above, there may be an opportunity to develop a supply hub further south in Victoria, and concerns have been raised that the introduction of a GSH at Moomba in the near future might detract from liquidity at Wallumbilla, which itself is still in the early stages of its development.[67]

3.2.5 Efficient reference price

Reference prices are important to help market participants and users form expectations about future price levels when entering bilateral contracts. Currently, neither the STTM nor the DWGM appear capable of providing a credible indicator of underlying demand and supply due to prices in these markets reflecting daily imbalances between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to only a very small portion of total volumes transacted on the markets (~5 – 20 per cent) meaning that the observed market price is susceptible to both a small volume of trades and a small number of market participants.

Given its location at a centre of both supply and demand, the DWGM may have the potential to be used to form a reference price, and a number of derivative products have been introduced by the Australian Stock Exchange (ASX) linked to the price payable at the beginning of the day in the DWGM. However, these products have not been heavily traded, which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream

66 APA, Discussion Paper submission, p. 10; Origin Energy, Discussion Paper submission, p. 4.

67 GDF Suez, Discussion Paper submission, p. 10; Stanwell, Discussion Paper submission, p. 6; QGC, Discussion Paper submission, p. 5.

producers using bilateral contracts, and then selling it to themselves through the DWGM.

In addition, the derivative products only provide a hedge against the beginning of day price, and the price in the DWGM can be reset a further four times over the course of the day. Participants are also liable for deviation payments and uplift charges.

As a pure commodity market, the Wallumbilla GSH may have the potential, as it matures, to provide a credible reference price that reflects underlying demand and supply conditions in Queensland. However, such an outcome may be dependent on resolving the current limitation whereby physical constraints within the hub split trading across three locations.

3.2.6 Connected markets

The significant investment made in new and augmented transmission pipelines over the last two decades has ensured that all major markets in eastern and southern Australia are today physically interconnected.

However, as outlined previously, it is not clear that, in practice, gas can always flow seamlessly between markets. Barriers, such as the detailed nature of transportation contracts and transaction costs, may be limiting the extent to which pipeline capacity can be reallocated to its most valuable use.

3.2.7 Trading between markets

Due to the confidential nature of gas supply and transportation agreements, it is difficult to assess the materiality of current trade across markets. The absence of credible reference prices for gas and lack of pricing information for uncovered pipelines makes it difficult to know whether gas is flowing to highest value use.

However, the ability of users to access capacity contracted to others through trades has emerged as a major theme for the review. Although significant work has been carried out in this area by industry and governments, it appears that barriers remain and that liquid trading in secondary pipeline capacity has yet to materialise.

The ability to trade between the DWGM and contract carriage pipelines outside of Victoria also appears to be an unresolved issue. While some stakeholders have noted that steps have been taken in the last two years to address issues associated with the interface between the two sets of arrangements,[68] views have also been expressed that problems remain, particularly those associated with curtailment.[69]

3.3 Areas of focus for the review

As highlighted by the preceding analysis, our work to date suggests that there are a number of gaps between the current frameworks and the Energy Council's Vision. Although our work going forward may not be limited to only these areas, the following

68 APA, Discussion Paper submission, pp. 14-15; AGL, Discussion Paper submission, p. 5; Origin Energy, Discussion Paper submission, p. 3; APGA, Discussion Paper submission, p. 34.

69 APA, Discussion Paper submission, p. 15; Origin Energy, Discussion Paper submission, p. 3; Santos, Discussion Paper submission, p. 6.

three issues are those which we currently consider are likely to form the main areas of focus for the reviews.

3.3.1 Liquid wholesale market delivering efficient reference price

Although there are three different types of facilitated market on the east coast, in five different locations, none yet deliver an efficient reference price. It is not clear that there is currently any strategic plan regarding the type and location for facilitated markets, and we consider that this is something that should be addressed.

We consider there are also questions regarding the objectives for, and design of, each type of market:

- **STTM**: It is not clear that the delivery of an efficient reference price is likely to be a realistic expectation of the STTMs, given the difficulties of developing any significant volume of commodity trading at points so remote from production. Consequently, we consider there to be a question as to whether the STTM market design can be simplified to reflect a reduced set of objectives.
- **DWGM**: It will be important to fully understand why more trading between participants is not occurring in the DWGM, and whether it would be possible to establish a more meaningful reference price. One issue appears to be the market design, where intra-day revisions to the market price and the existence of a number of ancillary charges prevent the identification of a "clean" price to form the basis of derivatives trading.
- **GSH**: The GSH at Wallumbilla appears to represent a good model for a wholesale trading market. However, the market design is incomplete, in terms of its ability to address physical constraints within the hub. We note that resolving this issue may have significant implications for the wider regulatory frameworks, for instance if there was a need for economic regulation of hub services.

Information

An important consideration in developing liquid and workably competitive markets is that participants have ready access to the information they require to make informed consumption, production, transportation and investment decisions.

Unlike some other markets, gas and gas transportation services in the eastern Australian gas market have historically been sold under confidential and highly customised medium to long-term contracts. The resulting lack of transparency means that the price discovery process can involve lengthy bilateral negotiations and may be afflicted by informational deficiencies and asymmetries.

Although some steps have been taken to try to reduce informational barriers, there are still some informational gaps, which are becoming more apparent as participants seek to adapt to the increasingly dynamic market environment. We therefore consider that there are important questions as to whether improvements can be made to the coverage, timeliness and accuracy of market and transportation information to assist the price discovery process and, over the longer term, enhance the liquidity of trading.

3.3.2 Ability to trade pipeline capacity in response to price signals

The increasingly interconnected nature of the gas transmission pipelines on the east coast and the impacts of the LNG export industry are two of the factors driving a much increased interest in trading pipeline capacity. Such trade is important to allow the market to reach efficient outcomes.

Whiles most stakeholders raising this issue have referred to situations in which prospective users seek access to contracted but unutilised capacity, it is also important that trades can be facilitated in situations where capacity being used can be traded to another party if they value it more highly.

Given that pipeline operators offer as-available capacity and shippers would appear to have an incentive to offer unused capacity (or capacity which is not highly-valued), we are interested to develop a better understanding of why more of a market has not developed.

A number of stakeholders have highlighted an apparent tension between demand for increasingly bespoke and tailored gas transportation contracts reflecting the more complex market environment on the one hand, and a need for more standardised contracts in order to allow for capacity trading on the other. Fully understanding this issue is therefore likely to require assessing a number of factors including contractual provisions, the incentives acting on a range of parties, the practicalities and costs associated with trading capacity, and processes for using pipelines.

3.3.3 Pipeline investment in the DTS

The nature of the market carriage arrangements are such that shippers cannot obtain firm access rights for the transportation of gas and therefore have little incentive to underwrite investments in the pipeline system. However, it is not currently clear whether a mechanism to allocate firm rights to shippers in response to them funding network augmentation could be accommodated within the current DWGM market framework or whether this would require significant redesign of the market.

In the absence of market-led investment, most capacity expansions have been progressed through the regulatory process. However, with the major driver on network expansion being a requirement to enhance the ability to ship gas across the system for "export" to other jurisdictions, it is questionable whether it is appropriate for the risks associated with over-investment to be borne by Victorian consumers. Inconsistent views have also been expressed as to the effectiveness and timeliness of the regulatory process, which we are keen to understand further.

3.4 Directions and recommendations

The issues identified above are those likely to form the major areas of focus for the reviews are complex and long-standing. As set out in section 3.1.1, the market and regulatory frameworks have evolved in a somewhat piecemeal manner since the development of the initial gas access regime in the 1990's. Consequently, fully understanding the issues and then developing and assessing potential solutions is likely to require detailed analysis and consultation with industry.

Stage 2 of the review is intended to allow for the development of any medium and long term adjustments necessary to implement the Vision. Our current view is that many of the issues identified to date are likely to fall into this category. In most cases, the ability to identify any useful incremental changes is likely to be limited. Progressing these issues first requires the long term roadmap for market development to be defined.

Nevertheless, we consider that there are some areas where more immediate progress can be made. This section therefore also discusses these matters and our proposed approach to progressing them.

3.4.1 Directions for stage 2 and the treatment of medium to long term issues

There are a number of complex and interlinked issues that require consideration in order to develop a long term market development plan. We intend to progress these in Stage 2 of the reviews, as follows:

- There appears to be a strong case for **redesigning the STTM**. The market is trying to achieve multiple objectives and, as a result, is complex and costly. We intend to consider whether it would be possible to simplify the design, which most likely will be based around a balancing market. We will consider the interaction with commodity trading at current and potential GSH locations. There may be merit in trialling a simplified market design at Brisbane and we have made a recommendation in relation to this in section 3.4.2.
- Similarly, we also intend to **reconsider the design of the DWGM**, to establish whether energy prices can be separated from balancing and uplift charges. In doing so, we will consider the potential for harmonising the balancing element of the market with the design of the STTM and the commodity element with the GSH.
- As part of this work, we will examine the potential to **introduce capacity rights to the DWGM**, with objective of better facilitating market-led investment in network expansion. Allowing participants to signal the need for capacity augmentation would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it.
- We intend to consult with industry to **develop a long term strategy for the location of facilitated markets**. We will work closely with AEMO as it develops a conceptual design of the Moomba GSH. We will consider how and when such a design will best fit into the wider east coast framework, including an assessment of the likely effect on liquidity in the broader market. This will be informed by the more detailed STTM and DWGM market design work, and will also consider broader questions, such as whether trade should be at specific physical location or at "virtual" points encompassing parts or all of the pipeline network.
- We note that AEMO is also progressing a workstream to **further develop the Wallumbilla GSH**, including investigating the potential for the provision of hub services. There is likely to be merit in complementing the technical work being conducted by AEMO by investigating the effects on the competitive landscape for the provision of hub services as part of Stage 2 of this review (including the possible need for economic regulation).

- A major element of the Stage 2 work will be to investigate and **consider potential measures to better facilitate pipeline capacity trading**. Building on our recommendation in this report to consider the extent to which the current Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change is likely to address the issue, we also intend to examine and potentially draw on approaches to this issue used in international markets in Europe and North America (to the extent that they might be applicable to Australian circumstances). Doing so will require us to examine the current barriers to secondary capacity trading, such as the way in which point to point rights are specified, and to consider the implications of any potential solutions on the broader gas access regime.
- Finally, we intend to **consider the strategic direction for information provision, including the Bulletin Board**. We will assess whether the coverage, timeliness and accuracy of information can be improved and, if so, whether the benefits of any informational improvements are likely to exceed the costs. We also intend to consider the broader institutional issues involved, including the appropriate roles for private providers and governments in information provision.

3.4.2 Issues that can be progressed in the shorter term

The Commission has given consideration to a number of issues that can be progressed over the short-term to assist the facilitated markets and pipeline frameworks to better achieve the NGO. These include:

- improving price transparency through either a survey-based gas price index and/or aggregating existing publicly available information;
- establishing the Bulletin Board as a "one-stop-shop" for all gas market data, including enhancing compliance with BB requirements;
- assessing the degree to which additional informational gaps fall within the scope of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change and could be addressed under that process;
- establishing a technical working group to begin analysis on the potential simplification of the STTM design with the goal of transitioning these markets to a more focussed balancing market design;
- harmonising the start time of the "gas day", which currently varies across jurisdictions; and
- removing the limitation in the NGL on who can submit DWGM rule changes.

The Commission is of the view that these "no-regrets" measures can be implemented without undermining the second stage of our work to develop the medium and long term adjustments required in the east coast markets and pipeline frameworks to implement the Energy Council's Vision.

Improving price transparency

While some information on wholesale gas prices is available in the market, greater transparency may be required as a transitional measure until there is an efficient reference price for market participants to refer to. We would be interested in receiving feedback from stakeholders on two potential options to achieve this:

1. Developing a survey-based gas price index for short, medium and longer-term contracts (eg six months, three years and five years) with basic terms and conditions and supply from the major delivery points (ie Wallumbilla, Moomba, Longford, Port Campbell and Yolla).[70] We would like to get a better understanding of whether market participants consider that there would be value in this option and, if so, what the impediments to its development may be, how it could be conducted and who should be responsible for conducting it.
2. Aggregating existing publicly available information and anecdotal reports on gas prices[71] into a monthly, quarterly or bi-annual report and publishing this on the Bulletin Board. Such a report could form part of an existing report (eg the GSOO, the AER's State of the Energy Market or the AER's Weekly Gas Market Report) or be developed as a separate stand-alone report. Again, we would be interested in getting stakeholders' views on the value of such a report to market participants and policy makers, and who would be best placed to prepare it.

It is important to note that with both options, we are not proposing an approach which involves mandating the disclosure of confidential information. While such disclosure would increase transparency, it is unclear how much value the market would derive from this information given the prices payable under these contracts reflect the value of all the terms and conditions of supply and not simply the value of gas.

We are also not suggesting that increased transparency alone is the desired outcome. However, increasing the ease with which all market participants, particularly users, can access key information that is critical to informing the development of pricing expectations will lower overall search costs and is likely to be in the long term interests of consumers.

Bulletin Board "one-stop shop"

It is clear that the informational sources on the eastern Australian gas market are fragmented and there could be value in establishing the Bulletin Board as a "one-stop shop" for market-based information. We are therefore considering changes that could be made to the Bulletin Board within the confines of the existing reporting framework to make it a more comprehensive source of information, further improve its usability and functionality and improve the reliability of the information provided.

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70 For example, the contracts could be assumed to provide for the firm supply of gas, have a 100 per cent take or pay provision, a 100 per cent load factor, no make-up gas provisions and no ability to vary contract quantities, a CPI price escalation mechanism and no price review clause.

71 For example, ASX announcements, company reports and industry publications, such as EnergyQuarterly, which contain estimates of gas prices realised by producers and anecdotal reports of the new contract prices.

Our preliminary thoughts on the changes that could be made to the Bulletin Board to increase its scope and improve its usability and functionality are outlined in Table 3.1. There may be other relatively simple improvements that can be made to the Bulletin Board that would not require a rule change and we would welcome hearing stakeholders' views on this before we suggest that further work be carried out in this area.

Table 3.1 Suggested improvements to the BB

Improvement	Detail
Include information on prices from the facilitated markets	Develop a new facilitated markets pricing page that includes: • current and historic information on prices and other relevant information from the GSH, STTMs and DWGM; and • the AER's Weekly Gas Market Report.
Include planning and longer term forecasts information	Develop a new long-term forecast and planning page that includes the GSOO, the National Gas Forecasting Report and associated material.
Expand the scope of capacity listing	Expand the scope of the capacity listing page to include a separate listing service for gas, transportation and storage capacity.
	Consider, in consultation with APA and Jemena, the extent to which bids and offers on their respective capacity trading sites could also be published on the Bulletin Board so that prospective shippers can find this information on a single website
	Reconsider whether market participants should be required by the BB procedures to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Allow transportation and storage charges to be published	Reconsider whether market participants should be required to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Further improvements to the BB's layout and functionality	Continue to improve the usability and functionality of the Bulletin Board by, for example: • making key information easier to find on the home page; • developing separate pages for production, transmission and storage, which would include the information Bulletin Board facilities are required to provide AEMO; • providing greater clarity about what some of the data represents; • making greater use of some of the information

Improvement	Detail
	provided by Bulletin Board facilities and improving the website's charting capability[72]; and • establishing a new section for the BB procedures and the AER's compliance reports.

If the BB is to become a "one-stop shop" then market participants will also need to have greater confidence in the accuracy and timeliness of the information that BB facilities are providing than they currently do. There would therefore be value in the AER continuing to work with AEMO to streamline the process for monitoring and enforcing compliance, to identify and address areas of systemic non-compliance in a timely manner. This might include conducting audits, where necessary, of information provided in the last 6-12 months and working with BB facility operators to address any non-compliance issues.

Addressing additional information gaps

While the starting point for the Commission's assessment of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change will be the COAG Energy Council's rule change proposal, we also intend to consider whether there are any other informational gaps that fall within the scope of the proposed rule change[73] that could also be dealt with at this time. This would potentially include suggestions made by stakeholders for information on storage facilities including daily volumes, data on linepack, as well as further improvements be made to the medium-term capacity outlook information that BB facilities are required to provide to AEMO.[74]

STTM simplification

The Energy Council's Vision clearly outlines a desire for the development of an efficient reference price. Given its current design, delivery of an efficient reference price is unlikely to be a realistic expectation of the STTMs, given the difficulties of developing any significant volume of commodity trading at points so remote from production. While there are still a number of questions that need to be answered in Stage 2 of the review about the number, location and design of various market mechanisms, it appears inevitable that the STTM model must evolve. Stakeholder submissions also support the view that the STTM is overly complicated for the purpose it is currently serving and may be imposing unnecessary transaction costs on market participants.

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72 For example, the actual flow data charting capability could include information on standing capacities as well as actual flows

73 The scope of the rule change has been described by the COAG Energy Council as rules "relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of the GSOO; and enable a more accurate understanding of gas flows in Australia's eastern gas market and in turn allow a better representation of gas flows to be published on the BB". COAG Energy Council, *National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information*, 30 March 2015, p. 3.

74 Implementing this change would require amendments to rules 165, 168 and 171.

We are therefore suggesting the formation of a technical working group led by the AEMC and including AEMO, market participants and others as appropriate that will be tasked with scoping how to transition the STTM from its current design to one focussed more specifically on balancing. The group will provide their assessment back to the AEMC to be considered as part of our Stage 2 recommendations on the broader market design framework.

Harmonising the gas day start times

Gas days currently start at differing times across the east coast.[75] Harmonising gas day start times may remove some of the complexity for parties that operate across multiple markets and assist the process of increasing the interoperability across all the facilitated markets. This would be likely to reduce transaction costs, and could therefore promote the NGO.

Given the widespread support shown for such a change to-date through submissions to the Discussion Paper, the final Stage 1 recommendations of this review could include a rule change that the Energy Council could submit to align gas day start times. We would be interested in the views of stakeholders regarding the practicalities of implementing such a change, in particular whether gas day start times should be harmonised across gas markets alone (and, if so, what time should be selected and why), or whether this harmonisation should also include the electricity market (ie aligning the gas day start times with the 4.00am day start time in the National Electricity Market). The AEMC is also interested to hear views on any costs that may accompany this change, for example the amendment of existing bilateral contracts and the recalibration of metering systems.

DWGM rule changes

Section 295(3) of the NGL provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[76]

We note that this restriction was raised in the 2013 Victorian Gas Market Taskforce Report. In particular, as part of the Gas Market Taskforce review, stakeholders stated that engaging with AEMO prior to a rule change is submitted processes is a time and resource consuming exercise, which represents a barrier for smaller market participants and potential new entrants to influence market development.

While the Taskforce did not come to a position on these issues, it recommended the Victorian government consider the merits of revisiting NGL section 295(3) and the appropriateness of adopting an open standing rule change process for the DWGM, as has been done in the electricity sector.[77]

We note that the restriction on who can submit a rule change request for the DWGM was also raised in submissions to the 2013 AEMC Gas Market Scoping Study. In particular, this limitation was claimed by many stakeholders to be unnecessary and in

75 6.00am in Victoria, 6.30am at the Sydney and Adelaide STTM hubs, and 8.00am at the Brisbane STTM hub and Wallumbilla supply hub.

76 Victoria is currently the only adoptive jurisdiction.

77 Victorian Government, *Gas Market Taskforce*, Supplementary Report, October 2013, pp. 79-80.

direct contrast to the STTM, where any party can initiate a rule change request. Some stakeholders also noted that it can result in sub-optimal outcomes because AEMO's consultation process tends to be consensus driven.[78]

To address these issues, we recommend that this restriction be removed. This would mean that any party would be able to propose rule changes applying to the DWGM, in manner consistent with the arrangements applying to the STTM, as well as those applying to the electricity sector through the National Electricity Rules.

78 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 95.

4 Transmission Pipeline Frameworks

Box 4.1 Summary of findings and recommendations

The ability of gas to flow to where it is most valued is inextricably linked to the conditions prevailing in the transmission segment of the supply chain. It is relevant therefore to consider whether the current regulatory and market arrangements are enabling gas to flow to where it is valued most.

Based on our analysis, the submissions received to date and observations from earlier reviews, it would appear that there are some aspects of the current arrangements that are impeding the efficiency with which:

- secondary capacity is allocated and used on contract carriage pipelines;
- investment in transportation capacity occurs on the DWGM; and
- gas can be exported out of Victoria, which, in part, appears to stem from interoperability issues between the market and contract carriage models.

These issues are complex and will require more detailed analysis than can be achieved in Stage 1 of this review. We therefore intend to consider:

- the first of these issues in further detail in Stage 2 of the East Coast Gas Review and the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change process; and
- the second and third issues in the DWGM Review and, to the extent relevant, Stage 2 of the East Coast Review.

As part of these more detailed reviews, we will also consider whether:

- the regulatory framework is still fit for purpose and is likely to remain so into the future given the changes underway in the market; and
- specific changes to the regulatory framework (including the third party access regime) may be required to improve the efficiency with which pipeline capacity is allocated, investment decisions are made in the DWGM and gas is traded and moved between jurisdictions.

4.1 Background

Transmission pipelines enable gas to be transported under high pressure from production facilities to the entry point of a distribution system, or to users connected to the transmission pipeline.

Over the last 15 years there has been significant investment in this segment of the gas supply chain in eastern Australia, with 13 new pipelines constructed (including the Eastern Gas Pipeline, the SEA Gas Pipeline, the QSN Link and the three pipelines servicing the LNG facilities) and a large number of other pipelines undergoing expansion, or conversion into bi-directional pipelines. Some investment has also been carried out in storage facilities. These investments, which have occurred in response to firm long-term commitments by shippers, have facilitated the development of a more interconnected system in eastern Australia. In doing so, the investments have increased the supply options available to buyers in most major demand centres and facilitated a greater degree of inter-basin competition. The current degree of pipeline interconnection in eastern Australia can be seen in Figure 4.1

Figure 4.1 Transmission pipelines in eastern Australia

Key: Major pipelines in bold. Blue = full regulation, Purple = light regulation , Green = 15 year no coverage

NSW

MSP – Moomba to Sydney Pipeline (APA) (half light)

EGP – Eastern Gas Pipeline (Jemena)

CRP – Central Ranges Pipeline (APA) (full regulation)

CWP – Central West Pipeline (APA) (light regulation)

SA

MAPS – Moomba to Adelaide Pipeline System (Epic)

SEA Gas Pipeline (APA 50%, Rest 50%)

SESA Pipeline - (APA)

SEPS Pipeline - (Epic)

Riverland Pipeline – (AGNL)

Vic

DTS – Declared Transmission System (APA) (full regulation)

Interconnect – (APA)

CHP – Carisbrook to Horsham Pipeline (Gas Pipelines Victoria)

SGP – South Gippsland Pipeline (Multinet)

Qld

RBP – Roma to Brisbane Pipeline (APA) (full regulation)

SWQP – South West Queensland Pipeline (APA)

QSN Link – Queensland, SA, NSW Link (APA)

QGP – Queensland Gas Pipeline (Jemena)

CGP – Carpentaria Gas Pipeline (APA) (light regulation)

BWP - Berwyndale to Wallumbilla Pipeline (APA)

WDD – Wallumbilla to Darling Downs Pipeline (Origin)

CBP – Cheepie to Barcaldine Pipeline

DVP – Dawson Valley Pipeline (Meridian and Westside JV)

NQGP – North Qld Gas Pipeline (Victorian Funds Mgt Corporation)

QCLNG Pipeline - (APA) (15 year no coverage)

APLNG Pipeline - (Origin, ConocoPhillips and Sinopec) (15 Year no coverage)

GLNG Pipeline - (Santos, PETRONAS, Total, KOGAS) (15 Year no coverage)

Tasmania

TGP – Tasmanian Gas Pipeline (TGP Pty Ltd)

Source: AEMO, 2012 Gas Statement of Opportunities. Amended to reflect the location of LNG facilities, ownership and regulatory status of pipelines.

Regulatory framework

The bottom of Figure 4.1 sets out the ownership interests and regulatory status of all the transmission pipelines in eastern Australia. As this information reveals, only 5.5 pipelines are currently regulated, three of which are subject to full regulation and 2.5 to light regulation.[79] The remainder are either unregulated, or subject to a 15 year no coverage determination. A brief overview of the third party access regime applying to transmission pipelines is provided in Box 4.6 (see Appendix D for further detail).

Box 4.2 Third party access regime and access regulation

The third party access regime and access regulation provisions applying to transmission pipelines are set out in the National Gas Law (NGL) and the National Gas Rules (NGR), which came into effect on 1 July 2008. Prior to 1 July 2008, pipelines were subject to the access regime and regulatory framework set out in the *Gas Pipeline Access (South Australia) Act 1997* and the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code).

The third party access regime adopted in the NGL and NGR largely mirrors the declaration and undertaking provisions in Part IIIA of the *Competition and Consumer Act 2010* (CCA). Under this regime, a pipeline can become covered and subject to either full or light regulation in one of the following ways:

- the pipeline was deemed a covered pipeline when the Gas Code came into effect;
- a coverage application is made to the National Competition Council (NCC) and the relevant Minister, having regard to advice from the NCC, is satisfied the pipeline meets all the coverage criteria in the NGL (see Figure 4.2);
- an unregulated pipeline voluntarily submits an access arrangement to the AER; or
- the pipeline is developed through a tender process approved by the AER.

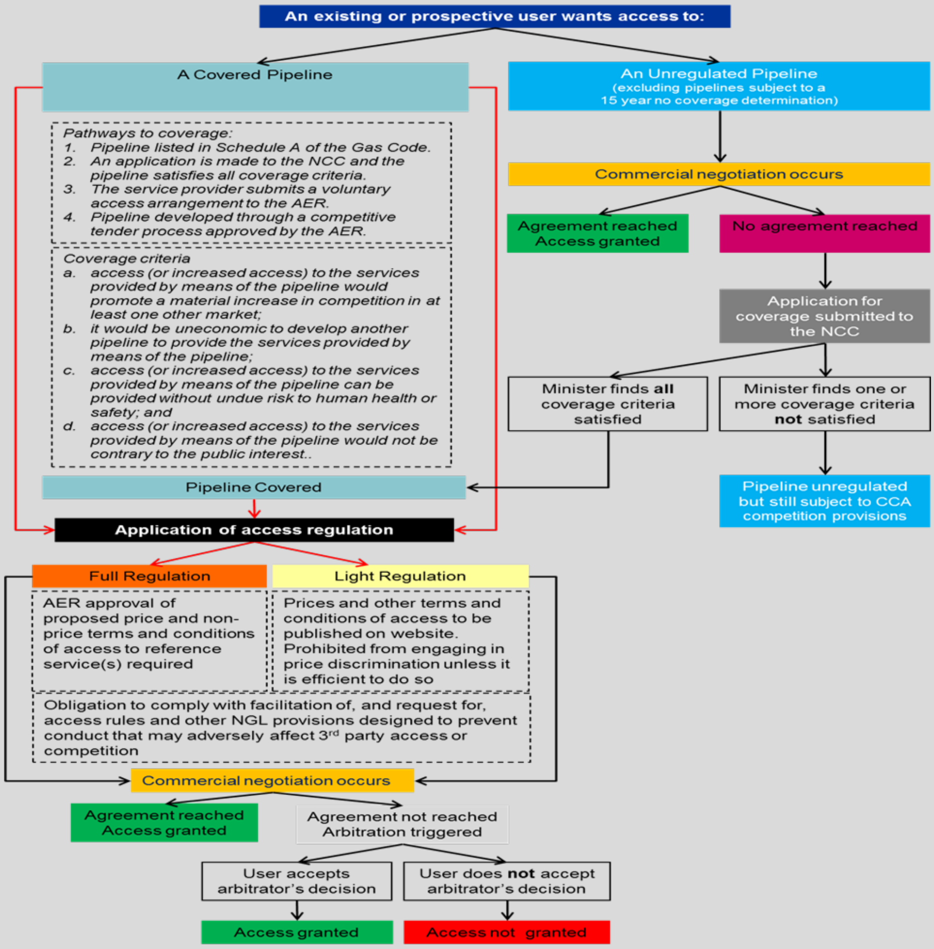
The access regime also provides for a pipeline's coverage status and form of regulation to change and 15 year coverage exemptions for greenfield pipelines if certain conditions are satisfied.

If a pipeline is covered then it may be subject to full or light regulation,[80] depending on the degree of market power the pipeline possesses and the likely costs of the two forms of regulation.

79 The three pipelines subject to full regulation are the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline. The 2.5 pipelines that are subject to light regulation are the Carpentaria Gas Pipeline, the Central West Pipeline and the Moomba to Sydney Pipeline from Marsden to Sydney (the remaining half of the Moomba to Sydney Pipeline is unregulated).

80 The only exception to this is if the pipeline is a "designated pipeline". The DTS is the only designated transmission pipeline in eastern Australia. See Victorian Gvt Gazette No. S222m, 30 June 2009.

Figure 4.2 Coverage criteria (section 15 of the NGL)



The main differences between these two forms of regulation are:

- Under full regulation, the pipeline operator is required to obtain the AER's approval for the price and terms and conditions of access to the reference service(s) set out in the proposed access arrangement.[81] Although AER approval is required, the pipeliner and users (or prospective users) are free to enter into an agreement that differs from the access arrangement. If a dispute about access arises, however, the arbitrator is required to give effect to the approved access arrangement.
- Under light regulation greater emphasis is placed on commercial negotiation and information disclosure, but provision has been made for parties to have recourse to the dispute resolution mechanism if negotiations fail. The pipeline operator is also prohibited under this form of regulation from engaging in conduct that may adversely affect access and/or competition in upstream or downstream markets.

If a pipeline is not covered, third party access can still be sought, but recourse cannot be had to the safeguards provided for in the NGL. An unregulated pipeline may also be required to provide AEMO with certain information for publication on the BB or for the operation of the STTM.

81 A reference service is defined in the rules as a service likely to be sought by a significant portion of the market. On the RBP (which operates under the contract carriage model), the reference services are firm transportation service from Wallumbilla or Peat to Brisbane. If it could be shown that the "as available" service was sought by a large proportion of the users of the RBP then it could be classified as a reference service too but that is not currently the case.

Market carriage and contract carriage models

There are currently two different models used to allocate and manage pipeline capacity in eastern Australia:

- the market carriage model, which provides open access to the Victorian DTS and uses outcomes from the operation of the DWGM to schedule injections and withdrawals from the pipeline; and
- the contract carriage model, which is in use on all other pipelines and relies on bilateral contracts between the pipeline operator and shippers to allocate pipeline capacity.

One of the more fundamental differences between these two carriage models is that shippers using a contract carriage pipeline can reserve firm capacity on the pipeline through bilateral contracts, while shippers on the DTS cannot. Shippers on the DTS may, however, hold AMDQ or AMDQ Credit Certificates (jointly referred to as AMDQ), which provide certain financial and market benefits, and some limited physical benefits.[82]

Other key differences between these two carriage models are set out in Table 4.1 below.

82 AMDQ provides holders with a hedge against congestion uplift charges up to Authorised Maximum Interval Quantity and entitles the holder to higher priority than customer with no AMDQ if there is a tie in injection bids or if curtailment is required to maintain system security. See Appendix F for more detail on AMDQ.

Table 4.1 Differences between the contract and market carriage models

	Contract Carriage	Market Carriage
Pipeline characteristics	Traditionally point-to-point	Meshed network
System operator	Pipeline owner (pipeline operator)	Independent system operator (AEMO)
Services	Firm (or ranked priority), as available or interruptible transportation services, storage and loan services, overrun/imbalance services	Standardised injection/withdrawal services AMDQ CC
Means by which shippers access services	Bilateral contracts entered into with the pipeline operator, the majority of which involve the reservation of firm capacity	Because the DTS operates on an open access basis shippers do not have to enter into contracts with the pipeline operator. They just have to be registered as DWGM participants, enter into a payment deed with the DTS and connection agreement with distribution networks
How pipeline capacity is allocated on a daily basis	Daily nomination process - firm services are accorded a higher priority than as available or interruptible services when there are constraints. Unutilised contracted capacity can be traded by shippers or the pipeline operator	Through the DWGM gas scheduling process
Basis on which investment decisions are made	Typically underpinned by medium to long-term contracts with shippers, with shippers allocated firm capacity rights	Through regulatory process because shippers are usually unwilling to underwrite investments they cannot guarantee firm access to

An overview of some of the trade-offs between the market and contract carriage models are set out in Box 4.3.

Box 4.3 Economics of transmission pipelines

Transmission pipelines involve investments with large fixed costs, long lives, and often a high degree of specificity to a particular asset or relationship. There is a need to recover significant capital costs in the presence of substantial, long-term risk.

One option to mitigate these investment risks is for transmission pipelines to be vertically integrated with production, distribution and retailing. However, where transmission is vertically separated from upstream and downstream sectors, long-term contracting may be used as an alternative to vertical integration. The very nature of transmission pipelines has implications for market outcomes and what may be reasonably expected.

Under the contract carriage model, the initial investments in upstream production and transmission pipelines can be underpinned by long-term Gas Supply Agreements (GSAs) and Gas Transportation Agreements (GTAs), entered into with foundation customers. From a foundation customer's perspective, both contracts are required because gas and transportation services are complementary products. In return for entering into these long-term contracts, foundation shippers are accorded firm rights to both the supply of gas and capacity on the transmission pipeline, which at times may be a scarce resource.

When a pipeline is fully contracted, the contract carriage model may involve a trade-off between:

- improving the efficiency with which the pipeline is utilised by allowing participants that do not have firm capacity rights to gain access to unutilised capacity on reasonable terms and conditions; and
- not undermining the incentive shippers have to underwrite the development or expansion of pipelines by diminishing the value of their firm capacity rights.

Any arrangement that seeks to facilitate access to secondary capacity will therefore need to carefully consider this trade-off between allocative and dynamic efficiency.

Efficiency trade-offs are not unique to the contract carriage model. It can also occur under the market carriage model when new investment is required. That is, while the open access model may provide for the efficient use of the DTS, the absence of any firm transportation rights means that shippers have only a limited incentive to invest in capacity (ie because they cannot guarantee access to the capacity they fund), which can have adverse effects on dynamic efficiency.

Recent developments in the transmission segment

In order to accommodate the structural changes underway in the broader east coast Australian gas market the transmission network is becoming increasingly interconnected. This interconnection is being supported by significant investments, including:

- the QSN Link, SWQP, Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline System,[83] which are being converted into bi-directional pipelines to enable gas to flow from the Cooper Basin and Victoria to Wallumbilla and excess gas produced by the LNG facilities to flow into south eastern Australia;[84]
- the Roma to Brisbane Pipeline and Berwyndale to Wallumbilla Pipeline, which are being converted to bi-directional pipelines to enable gas to flow to and from Wallumbilla;[85] and
- the DTS, which is being expanded to enable more gas from Victoria to flow into New South Wales and Queensland.

Some investment is also being carried out in the Wallumbilla Supply Hub to facilitate the movement of gas across the hub.[86]

These investments are allowing for more flexible and dynamic transportation and storage service offerings across multiple pipelines and will enable the direction of gas flows to change more rapidly in response to changes in demand and supply.

Apart from driving new investment, the changes underway in the market are also affecting the nature of the demand for transportation and storage services and the degree of flexibility sought by some market participants. For example:

- LNG proponents and market participants that are able to respond relatively quickly to short-term changes in the availability of gas[87] are looking for flexible services to transport or store gas across multiple pipelines and between multiple receipt and delivery points as and when required.
- Higher gas prices and uncertainty about the availability of gas are reportedly starting to have an adverse effect on the demand for gas and transportation services by some large industrial customers, which could adversely affect the utilisation of some pipelines.[88]
- Higher gas prices and weaker conditions in the NEM are also adversely affecting the demand for gas and transportation services by those gas fired generators that have been unable to take advantage of the lower priced "ramp" gas that has been available in the lead up to the commissioning of the LNG facilities.

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83 The MAPS pipeline is also being connected directly to the SEA Gas Pipeline.

84 AEMO, *2015 Gas Statement of Opportunities*, April 2015, p. 3 and APA presentation, *The changing face of gas transmission service*s, 18 September 2014.

85 APA website, http://www.apa.com.au/our-business/energy-infrastructure/queensland.aspx

86 APA, *Annual Report 2014*, p. 3.

87 For example gas fired generators.

88 For example, BP announced in 2014 that it would be closing the Bulwer Island refinery in Brisbane. See Brisbane Times, Brisbane’s job losses as BP refinery is closed, 2 April 2014.

Submissions to this review suggest that pipeline operators have responded to the changing needs of some segments of the market by:[89]

- offering more flexible and bespoke transportation and storage services and shorter term contracts to meet the needs of those shippers seeking a greater degree of flexibility;[90] and
- taking steps to facilitate the trade of contracted but unutilised capacity[91] and selling that capacity themselves on an "as available" basis.

Matters considered in the chapter

The transmission segment appears to have responded in a relatively dynamic way to the structural changes underway in the market. However some market participants and policy makers have questioned whether the current regulatory and market arrangements are sufficiently flexible to deal with future market conditions. Questions have also been raised about whether the arrangements are enabling gas to flow to where it is valued most, or if there are factors that are impeding:

- the efficient allocation and use of contracted but unutilised pipeline capacity (section 4.2);
- the efficient and timely investment in transportation capacity, particularly in Victoria (section 4.3); and
- the efficient trade and movement of gas between jurisdictions (section 4.4).

Some parties have also questioned whether the regulatory framework is still fit for purpose given the changes underway in the market (section 4.5).

These matters are considered in detail below.

89 APGA, Discussion Paper submission, March 2015, pp. 5-6, APA, Discussion Paper submission, 26 March 2015, p. 6, Jemena, Discussion Paper submission, 26 March 2015, Epic Energy, Discussion Paper submission, 27 March 2015, p. 2 and Origin Energy, Discussion Paper submission, 26 March 2015, p. 5.

90 For example, firm services are being supplemented with "as available" or interruptible transportation, storage, loan and other ancillary services. Ranked priority services are also being offered on some pipelines to provide a firm service outside peak periods. Greater flexibility is also reportedly being provided in terms of enabling changes to delivery and receipt points in existing contracts and allowing intra-day nominations.

91 For example, through the development of capacity trading platforms and other measures that are designed to reduce the impediments to capacity trading (eg in-pipe trades or imbalance trades).

4.2 Efficient allocation of pipeline capacity

In a market of growing dynamism and uncertainty, contract lengths appear to be shortening and more options for trading are required. Until recently, market fundamentals were more predictable and long-term contracts were relatively effective. However, with the changes currently underway in the market, allocating gas to those that value it most is becoming more challenging and increasingly linked to the efficiency with which pipeline capacity is allocated. This appears to be leading some stakeholders to advocate the adoption of measures that will increase the level of capacity trading on contractually congested pipelines.

Contractual congestion is said to occur when a contract carriage pipeline is fully contracted, but not fully utilised. A secondary capacity trade in this case could improve the efficiency with which gas is allocated if a shipper that does not have access to the capacity required to transport gas on a particular pipeline, values the capacity more than the holder of that capacity, and a trade occurs (see Box 4.4). Trades of this nature can lead to improved utilisation of existing pipeline capacity, provide market participants with a greater degree of flexibility and risk management options, and facilitate a greater degree of upstream competition. This type of trade may also reduce barriers to entry for prospective shippers, which may, in turn, have a positive effect on competition in downstream markets.

Capacity trading has also been highlighted in previous reviews as an important area for reform because it is believed that it will:

- improve the efficient operation of contract carriage pipelines;
- provide market participants with a greater degree of flexibility to access cheaper sources of gas and to manage risks; and
- act as a conduit for upstream competition.

Some of the barriers to capacity trading that stakeholders have cited, include:

- prohibitive search and transaction costs for shorter-term trades and technical constraints on defining capacity rights; and
- the failure of primary capacity holders and/or pipeline owners to release capacity, which may occur for strategic reasons, or because the capacity holder places a higher value on the unutilised capacity than a prospective shipper.

These barriers are explored in detail in the remainder of this section.

Box 4.4 Capacity trading basics

If a firm capacity holder on a pipeline (primary capacity holder) has any spare pipeline capacity, it may decide to on-sell it to another shipper that is in a position to utilise the pipeline capacity. This secondary trade may take the form of either:

- a bare transfer, which results in the contract holder's rights (or part thereof) being temporarily transferred to the counterparty but the contract holder remains responsible for the financial and operational obligations in the agreement (such as pipeline nominations); or
- a novation, which results in the contract holder's rights and obligations under the GTA being permanently transferred to the counterparty.

The contract holder's willingness to enter into such a trade will depend on:

- how much spare capacity it has and the period over which it is available;
- the opportunity costs of not entering into the transaction;
- commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market; and
- the transaction costs associated with entering into such an arrangement (ie negotiation and contracting costs and ongoing contract management costs).

The counterparty's willingness, on the other hand, will depend on whether:

- the counterparty is able to make use of the pipeline capacity, which will depend on its end-use requirements and contractual position;
- the period over which the capacity is to be supplied corresponds with the period over which the counterparty can use the capacity;
- the firmness of the capacity meets the counterparty's requirement; and
- the total cost of entering into the transaction (including price and any transaction costs) as compared to the cost of any substitute service.

Due to the confidential nature of these agreements, it is not possible to determine how frequently these types of transactions are used. Anecdotal evidence, however, suggests these transactions do occur but are not widely used.

In addition to being able to contract with the primary capacity holder, a prospective shipper may be able to enter a contract with the pipeline operator, who can sell any unutilised contracted capacity to other shippers on an "as available"[92] basis. Whether or not a counterparty will view an "as available" transportation service as a substitute for a bare transfer will depend on:

- whether the counterparty requires a firm service; and
- the price and other terms and conditions proposed by the pipeline operator.

92 If there is spare uncontracted capacity on the pipeline, the operator can also compete to provide firm transportation service.

4.2.1 Search and transaction costs

Prior transactions between two parties may allow subsequent trades to occur on a faster and lower cost basis than would otherwise have been the case. However, for a genuinely liquid market to develop, other measures may be required to reduce search costs and other transaction costs (eg contracting and negotiation costs), particularly for very short-term capacity trades.

For short-term capacity trades, search and transaction costs may be acting as an impediment to trade because shippers are unlikely to have the processes, such as standardised contracts, in place to quickly respond to these transactions.[93]

Participants' ability to engage in short-term capacity trading may similarly be limited by provisions in the primary capacity holders' contracts with the pipeline operator that restrict the ability or incentive to trade capacity, such as point-to-point delivery requirements, nomination cut-off times and other fees and charges. The fact that capacity rights are generally defined as being between two very specific points appears to naturally limit the ability of participants to trade (as few participants are likely to have exactly the same requirements), particularly on pipelines with multiple receipt and delivery points.

Recent developments in reducing search and transaction costs

Some steps have recently been taken to try to facilitate secondary capacity trading by reducing search and transaction costs.

Both APA and Jemena have established capacity listing websites, wherein participants can find one another through listing capacity bids and offers, and can thereafter perform capacity trades over the counter. APA's platform currently allows capacity on the South West Queensland, Carpentaria, Moomba to Sydney and Roma to Brisbane pipelines to be listed. The website includes other, basic information to facilitate the transaction. Jemena's platform allows capacity on the Queensland Gas Pipeline to be listed, and is expected to be expanded to include the Eastern Gas Pipeline.

In December 2012, the Energy Council commenced a process to consider whether further policy options could facilitate increased trade in transmission pipeline capacity in the east coast gas market. The final Regulation Impact Statement (RIS) on Gas Transmission Pipeline Capacity Trading was released a year later, in December 2013. This paper was subsequently endorsed by the Energy Council, which agreed to pursue the suggested enhancements to information provision and contractual standardisation. Specifically, the Energy Council endorsed:

1. the redevelopment of the National Gas Market Bulletin Board (BB) to improve the functionality and usability of the BB and the inclusion of a capacity listing service on the BB;
2. the development of voluntary standardised contractual terms and conditions applying to pipeline capacity; and

93 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 122.

3. the submission of a rule change to the AEMC requiring pipelines and shippers (via pipeline operators) to provide information concerning pipeline capacity utilisation and capacity trading activity, to be published by AEMO.

Work on the first two items was completed by AEMO in 2014 and there is now a capacity listing site on the BB and a standard form Capacity Trade Agreement contract on AEMO's website. The AEMC received the Energy Council's Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change request on 30 March 2015. Further detail on the rule change can be found in Chapter 8.

In addition to these developments, APA has reportedly developed:[94]

- a standard GTA with standardised terms and conditions to enable shippers to trade capacity more readily through either a bare transfer or through assignment;
- standard contractual terms for its capacity trading service that can be inserted into any existing transportation contract and enable parties to trade firm capacity rights; and
- an in-pipe trade service, which enables shippers to trade gas with other shippers irrespective of the physical receipt point using virtual receipt and delivery points.

We also note that the recently announced ACCC inquiry into the competitiveness of the wholesale gas industry will consider "transaction costs, information transparency and the competitiveness of, access to, and any restrictions on...gas transportation."[95] We intend to work and consult with closely with the ACCC given the complementarity of the analysis in the East Coast Review and the ACCC's inquiry.

Stakeholder submissions

There has been considerable engagement from stakeholders on secondary capacity trading across several review processes. As such we have considered previous submissions as part of our broader assessment of the issues.

Some stakeholders consider that the current arrangements are appropriate and that the Energy Council's rule change and other reforms should be tested in the market before further reforms are implemented.[96] Other stakeholders, however, are of the view that further reform (ie over and above what is contemplated in the rule change) in this area is required and have identified a number of potential reforms, which range from:[97]

- greater information provision to reduce search costs and increase the degree of transparency in the market – some of which extends beyond the issue of capacity trading to include gas supply and the activities of LNG producers (see Chapter 8); to
- the establishment of a secondary capacity trading platform or another market based mechanism that enables trade to occur more effectively and without the need to enter into bilateral negotiations.

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94 APA, Discussion Paper submission, 2015, p. 23.

95 Australian Government, *Inquiry into competitiveness of the Wholesale Gas Industry*, Terms of Reference, 8 April 2015.

96 For example Jemena, APA and APGA, Discussion Paper submissions, 2015.

97 GDFSAE, Discussion Paper submission, p. 6.

Some stakeholders also raised concerns about:

- technical and operational issues that may affect secondary capacity trading, such as contracting costs and point-to-point delivery points in GTAs;[98] and
- the effect that administrative charges levied by pipeline operators and other fees in GTAs costs may have on the costs of entering into secondary trades.[99]

There is considerable support amongst stakeholders for the standardisation of transportation contracts, although APA noted that standardisation is not a necessary condition for capacity trading:[100]

> "A capacity trade involves the trade of a particular part of an existing contractual arrangement, being firm capacity between two points. Other elements of the primary contracts are not traded."

4.2.2 Failure to release

The term "failure to release" is used in this context to refer to either:

- the primary capacity holders and/or pipeline operator choosing not to trade spare capacity; or
- a situation where the price at which the primary capacity holder or pipeline operator is willing to make capacity available is higher than the prospective shipper is willing to pay.

In the market for secondary capacity trading, a failure to release may occur when:

- competition for the provision of secondary capacity is ineffective, which could occur if:
  - there is only a single shipper on the pipeline that has contracted all of the pipeline's capacity;
  - the capacity that the pipeline operator can offer does not meet the prospective shipper's needs;
  - provisions in the operator's contracts with primary capacity holders, which limit its incentive and/or ability to compete with primary capacity holders for the provision of secondary capacity (eg terms that require the pipeline operator to rebate some or all of the revenue it receives from such sales to the primary capacity holders); and/or

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98 In particular, AGL identified a number of structural issues that may restrict capacity trading and suggested that: delivery points in GTAs be grouped into zones to provides shippers with greater flexibility without diminishing the pipeline operators' capacity to manage the pipeline; pipeline operators provide the allocation at the delivery point as part of a standard service, instead of shippers having to negotiate an allocation agreement; and nomination cut-off times should not be based on operational requirements that favour the capacity of pipeline operators over that of shippers.

99 AGL, Discussion Paper submission, 2015, p. 6. Santos, Discussion Paper submission, p. 7. Alinta Energy noted that exposure to unknown additional pipeline charges can be difficult to manage (Discussion Paper submission, p. 8). Stanwell noted that excessive fees are often charged on intraday nominations by pipelines (Discussion Paper submission, p. 3).

100 APA, Discussion Paper submission, 2015, p. 23.

— provisions in the primary capacity holders' contracts with the pipeline operator that limit their ability or incentive to trade capacity (see section 4.2.1).

- the primary capacity holders decide to hold onto their capacity for strategic reasons because:
  — the primary capacity holder wants to gain a competitive advantage in an upstream or downstream market by withholding ("hoarding" capacity);
  — the capacity provides the primary capacity holder with an option value; or
  — the capacity sought by the prospective shipper is too small to justify the costs that would be incurred in entering into the relevant contracts.

Observations from previous reviews

That participants may hoard or withhold capacity was questioned in both the Scoping Study and the Productivity Commission's recent research paper, *Examining Barriers to More Efficient Gas Markets*. For example, the Scoping Study noted that:[101]

> "Shippers and pipeline owners should have an incentive[102] to sell any spare capacity and, in theory, should compete against each other to sell the capacity. The latter of these points is of particular importance, because while a shipper may appear to have little incentive to sell spare capacity to a downstream competitor, the fact that a pipeline owner can sell that same capacity on an 'as available' basis, should encourage the shipper to compete to supply the service and recover some of its fixed transportation costs."

The Productivity Commission also questioned whether withholding capacity is necessarily an act of market power, and noted that what may appear to be inefficient hoarding of capacity may instead be "commercial behaviour that is consistent with outcomes from effectively competitive markets."[103] The Productivity Commission went on to add that "holders of firm capacity rights may also be retaining some spare capacity as a risk management tool in an environment of market uncertainty."[104] The latter of these points is likely to be of particular importance at present given the current market dynamics.

101 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, 2013, p. 113.

102 A pipeline owner should have incentives to sell capacity because the capacity has already effectively been paid for by the contracting shipper (ie because transportation charges are largely fixed and are payable irrespective of the volumes transported), so it will derive additional revenue from the sale. A shipper's incentive will depend on the opportunity costs associated with not entering into the transaction (which can be quite high because transportation costs are predominantly fixed) and commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market.

103 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 120.

104 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 49.

Stakeholder submissions

Several stakeholders raised the issue of failure to release, or capacity hoarding, in submissions to this review. For example, the Major Energy Users (MEU) noted that interruptible capacity offered by pipeline operators may either be offered at a higher cost than firm capacity or not offered at all, and that in instances of hoarding, the shipper may be trying to prevent competition.[105]

Adelaide Brighton also raised concerns about the ability of retailers to restrict the supply options available to customers by acquiring all the capacity on some regional pipelines and laterals and suggested this be addressed by introducing a capacity trading mechanism.[106]

AEMO also advocated examining ways to improve the incentives for shippers and pipeline operators to make available capacity, particularly on a short-term basis.[107]

A number of stakeholders also discussed the price that should be payable for unutilised pipeline capacity, with some contending that the price should be based on the marginal cost of providing the capacity, while others contended it should be equivalent to (or set a premium to) the price of firm capacity. For example, APLNG noted that "standard commercial terms based on a marginal cost basis would assist" in maximising the use of transportation capacity.[108] Epic Energy, on the other hand noted the following:[109]

> "In this excess capacity environment, 'As Available' services, if offered need to be priced at a level which reflects the economic costs associated with such a service. This price will be at a substantial premium to firm service, as it has substantially higher costs to the Pipeliner (and at a much greater risk) in providing it."

4.2.3 Measures to facilitate capacity trading

Stakeholders and previous reviews have proposed a number of different measures aimed at facilitating capacity trading, including:[110]

- a voluntary capacity trading market;
- an oversell and buyback regime;
- a new non-discriminatory third party access regime for the entire east coast gas market, that includes a number of measures to facilitate capacity trading and the efficient allocation of pipeline capacity.
- a mandatory trading obligation imposed on capacity holders; and
- an open access pipeline carriage model operated by an independent market operator (similar to the market carriage model in Victoria or the NEM).

105 MEU, Discussion Paper submission, p. 8.

106 Adelaide Brighton, Discussion Paper submission, p. 4.

107 AEMO, Discussion Paper submission, 2015, p. 3

108 APLNG, Discussion Paper submission, p. 2.

109 Epic Energy, Discussion Paper submission, p. 3.

110 See for example, QGC, Discussion Paper submission, Department of State Development Business and Innovation, Victoria's Energy Statement, 2014, p. 58 and Stanwell, Discussion Paper submission.

4.2.4 AEMC's Stage 1 findings

There is substantial interest in improving capacity trading arrangements and that there is some unmet demand for this service at present. It would also appear from our preliminary review that the existing arrangements are less than ideal and that more trades could occur, or could be expected to occur in the future, if some of the barriers outlined above were reduced.

There are further potential issues in pipeline capacity trading beyond search and transaction costs and failure to release. For example, on a point to point pipeline with multiple injection and withdrawal points, defining capacity rights and system operation may be especially difficult. System operation may also be a difficult challenge when gas flows are dynamic and gas travels between pipelines of different ownership.

Secondary trading of pipeline capacity is a complex issue and will require more detailed analysis than can be carried out in Stage 1. The Commission therefore intends to consider the barriers to secondary capacity trading, and the measures that can be put in place to reduce these barriers and encourage greater competition for the provision of secondary capacity in further detail in Stage 2 of the East Coast Review. In doing so, we intend to carry out a closer examination of:

- whether search and transaction costs can be further reduced by putting in place additional measures to those contemplated in the Energy Council’s proposed Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change;
- how any technical constraints on capacity trading may be addressed (including point-to-point delivery requirements);
- the significance of the failure to release issue and whether any measures (including those identified by stakeholders and those in place in other markets) may be required to encourage capacity holders and pipeline owners to make secondary capacity available and compete with each other for the provision of this service;
- the pricing of secondary capacity and the factors that are likely to affect the pricing of this service; and
- whether any changes may need to be made to the current market and regulatory arrangements to support capacity trading (see section 4.5 for further detail).

4.3 Timely and efficient investment in pipelines

As noted earlier, there has been significant investment in gas transportation infrastructure over the last 15 years. These investments, which have largely occurred in response to firm long-term commitments by shippers on contract carriage pipelines, have facilitated the development of a more interconnected system in eastern Australia and, in so doing increased the supply options available to buyers in most major demand centres and facilitated a greater degree of inter-basin competition.

While investment appears to have occurred in a relatively timely and efficient manner on contract carriage pipelines, concerns have been raised by a number of stakeholders and prior reviews about the effect that the following factors may have on the timeliness and efficiency of investment in the DTS:

- the inability of shippers to obtain firm capacity rights under the market carriage model (see Table 4.1 and Appendix F.2.2);[111] and
- the regulatory investment process and the application of the investment provisions in the NGR to fully regulated pipelines (see Box 4.5).

These issues are explored in the remainder of this section.

Box 4.5 Investment provisions in the NGR

The investment related provisions in the NGR can be found in **rules 79-86.** These rules apply to only to the three pipelines subject to full regulation (the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline).

Rule 79 sets out the matters that the AER must consider when determining whether or not capital expenditure incurred in the immediately preceding period and forecast capital expenditure can be considered 'conforming' capital expenditure and rolled into the capital base. Conforming capital expenditure is defined in rule **79(1)** as capital expenditure that would be incurred by a 'prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services' and is 'justifiable' on a specified ground.

Rule 80 allows the service provider to seek an advance determination from the AER on whether capital expenditure it proposes to undertake within the access arrangement period will meet the conforming capital expenditure criteria in rule 79.

Rules 81-84 set out how non-conforming capital expenditure can be treated under the NGR. While this capital expenditure cannot be rolled into the capital base, a service provider may still undertake this form of expenditure (**rule 81**). If it does so, it may:

111 The market carriage model provides open access to all shippers using the Victorian DTS. In order to access the system, shippers enter a Transportation Payment Deed to pay the owner of the DTS (APA) directly for their injections and withdrawals (use of the system), the price of which is regulated by the AER. Under the market carriage model, shippers do not have firm access rights to transport gas on the DTS. Shippers may, however, hold AMDQ which provides some financial and market benefits.

- recover that expenditure, or a portion thereof, through a surcharge approved by the AER **(rule 83)** or a capital contribution **(rule 82)**; or
- include the investment (or a portion thereof) in a 'speculative capital expenditure account', which increases annually at a rate determined by the AER (**rule 84**).

If a speculative capital expenditure account is established and the capital expenditure (or a portion thereof) is later found to satisfy **rule 79**, it can be rolled into the capital base.

Rules 85-86 contain the redundant asset provisions. **Rule 85** states that an access arrangement may include a mechanism that provides for:

- assets that cease to contribute in any way to the delivery of pipeline services to be removed from the capital base at the commencement of the next access arrangement period; and/or
- the costs associated with a decline in demand to be shared with users.

Before requiring or approving such a mechanism, the AER must take into account the uncertainty it would cause and the effect that would have on the service provider and users.

If a redundant asset later contributes to the delivery of services, it may be treated as new capital expenditure and added to the capital base under **rule 86**.

Observations from previous reviews

The Scoping Study, the Victorian Gas Market Taskforce, the Eastern Australian Domestic Gas Market Study and the Productivity Commission each noted that while significant investment has occurred recently, much of it had occurred on contract carriage pipelines and concerns remain about how the market carriage model affects investment in the Victorian DTS.

The Scoping Study noted that while the market carriage model appears to promote both the efficient use of the existing DTS infrastructure and dynamic efficiency in other markets, it may not be promoting timely and efficient investment in the DTS.[112] The Scoping Study also noted the following issues with the market and regulatory arrangements in Victoria:

- intra-period investment opportunities permitted under the NGR are not being utilised; and
- the DTS pipeline owner may have an incentive to avoid or delay investment to derive additional revenue from the auction of higher valued AMDQ and storage at the Dandenong LNG facility.[113]

112 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, 2013, pp. 112-113.

113 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, 2013, pp. 112-117. The issue of the application of the AER's investment regulation to export-related projects may not take account of benefits outside of Victoria was largely dismissed in the Scoping Study, see pp. 116-117.

Some stakeholders in the Scoping Study also suggested that the deferral of the expansion of the South West Pipeline (SWP) from the 2008-2012 to the 2013-2017 access arrangement period may have contributed to:[114]

- congestion on the SWP;
- higher spot prices in the DWGM; and
- shortages of AMDQ on the SWP, which had the potential to expose some users to congestion uplift charges.

Apart from affecting the productive efficiency of the DTS, these submissions suggested the delay may have imposed costs and risks on market participants and, in turn, consumers.

In its recent report on barriers to more efficient gas markets, the Productivity Commission noted that while all capital investments involve a lag between the time of final investment decision and when the capital becomes operational, delays beyond this lag can impose costs.[115] The Productivity Commission also noted pipeline owners concerns that the regulatory arrangements under the NGL[116] may increase the risks associated with investing in pipeline infrastructure, and therefore inhibit capacity investments:[117]

> "It is clear that access regulation can affect investment incentives. If pipeline owners are uncertain about how regulation would be applied and if there are risks associated with the arrangements for determining regulated prices to expansion, the risks from investing in pipeline infrastructure could be compounded. These risks could increase investors' hurdle rate of return…beyond the expected return, inhibiting capacity. Also if regulated rates of return are not expected to fully compensate investors for the risks incurred, investments may not proceed."

Stakeholder submissions

APA, APGA, EnergyAustralia, Epic Energy, ERM Power and ESAA noted that while the contract carriage model provides for timely market driven investment, the regulatory and market carriage model may act as a barrier to timely and efficient investment in the DTS.

APGA in particular noted that market carriage arrangements in Victoria require access regulation and "stifle the ability for timely private investment, therefore imposing significant costs on the community."[118]

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114 K Lowe Consulting, Gas Market Scoping Study, a report for the AEMC, 2013, p. 114.

115 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 108

116 For example, redundant asset provisions in NGR 85(1) and regulatory error in setting prices, terms and conditions for access to the expansion.

117 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 115.

118 APGA, Discussion Paper submission, p. 36.

As the owner of the DTS, APA expressed concerns about the effect of the regulatory and market arrangements in the DTS on investment, noting the "timing of new investment in capacity follows the regulatory cycle, rather than the requirements of users."[119] APA also expressed concerns about the free-rider effect resulting from the 'socialisation' of investment costs in the Victorian system, noting the market carriage arrangements mean that:[120]

- existing users may have to contribute to the cost of expansion even if their transportation requirements are unchanged and they have already funded their capacity requirements;
- new users (or existing users seeking to transport additional volumes of gas) may not face the full cost of their decision to transport gas; and
- users with volatile demand (such as gas fired generators or shippers seeking to move gas across the system) are subsidised by users with more stable capacity requirements, such as industrial users.[121]

APA noted that its most recent investments in the DTS[122] were made possible by bilateral contracting arrangements that were entered into outside of the market arrangements of the DWGM and should not be viewed as "proof" that investment can be market driven under the market carriage model.[123]

APA also expressed concerns about the effect that the redundant asset and speculative capital expenditure provisions in the NGR can have on investment (see Box 4.5).[124]

The Group of Leading Energy Companies and Major Users (GLECMU) noted that the "benefits of a single pipeline regulatory regime should be considered if the existing investment arrangements hinder market developments."[125]

In contrast, other stakeholders, including the AER, Lumo Energy and the MEU have questioned the materiality and veracity of claims that the regulatory arrangements are inhibiting investment.

In its submission, Lumo Energy stated that it "does not accept the view that the regulated model of transmission investment in the DTS is deterring the level and efficiency of the timing of transmission investment."[126] Lumo Energy added that the deferral of the SWP expansion from the 2008-12 access arrangement period to the

119 APA, Discussion Paper submission, p. 12.

120 APA, Discussion Paper submission, pp. 14-15.

121 APA, Discussion Paper submission, p. 14.

122 In the current regulatory period (2013-17) APA has made investments on the South West Pipeline to allow for additional gas from Port Campbell (approximately $40 billion) and on the Interconnect for additional northbound gas flows at Culcairn ($160 million): APA, Discussion Paper submission, p.13 & APA *Annual Report* 2014, Transmission. http://annualreport2014.apa.com.au/sites/default/files/documents/2014/APA001%20APA%20Review%20Transmission.pdf

123 APA, Discussion Paper submission, pp. 13-14.

124 APA, Discussion Paper submission, p. 26.

125 Group of Leading Energy Companies and Major Users, Discussion Paper submission, p. 3.

126 Lumo Energy, Discussion Paper submission, pp. 12-13.

2013-17 period highlighted the fact that the decision not to allow the investment in the earlier access arrangement period was correct:[127]

> "To the extent the relevant investment was uneconomical and failed the incremental revenue test…the option was still available for a market participant to put forward the funds to underwrite the investment shortfall in exchange for AMDQcc…The fact that a market participant failed to provide the investment shortfall…implies that the market was not ready for this investment to proceed."

The AER also noted that provisions in the NGR allow "a regulated pipeline owner to seek an approval binding on the regulator for a project at any time during a regulatory period." The AER also pointed to an application for pre-approval of a DTS investment (the Corio loop) made by the previous owner of the DTS:[128]

> "The application was made in 2005 and approved by the ACCC which facilitated spending and project completion before the commencement of the 2008-12 regulatory period."

AEMC's Stage 1 findings

The appropriate allocation of risks and timely and efficient[129]investment in infrastructure are, as noted in Chapter 2, key characteristics of workably competitive markets.

The market carriage arrangements in Victoria are such that shippers cannot obtain firm access rights for transportation of gas. The lack of exclusive rights to use any augmentation or expansion in the system means that shippers have little incentive to underwrite investments in the pipeline. Rather than decisions being driven by the market in Victoria, decisions on investment in the DTS are regulated by the AER. In contrast, shippers on contract carriage pipelines are able to secure firm access rights to the capacity expansions they underwrite with long term contracts, and investment decisions are driven by the market and underpinned by those contracts.[130]

In addition to the inability for the market to drive investment in Victoria, stakeholders and prior reviews also have expressed concerns about the potential for delayed investment in the DTS through the regulatory process. However, it is unclear at this stage whether these delays (real or perceived) are significantly impeding gas flows and if so, whether they are a result of a failing in the regulatory framework or the application of the regulatory framework.

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127 Lumo Energy, Discussion Paper submission, p. 13.

128 AER, Discussion Paper submission, pp. 3-4.

129 Investments in gas pipelines are efficient when their total benefits exceed the full economic costs of investment and those investments are made in a timely manner.

130 However, the Productivity Commission notes that delays in investment are not limited to market carriage arrangements. Negotiations that underpin contracts between pipeline owners and contract holders to underpin capacity expansions or augmentations can take months to negotiate. Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 111.

We are aware that there are provisions within the NGR that enable investments that have not been approved by the AER to occur within the access arrangement period. For example, Rule 80 allows the pipeline owner to seek advance determination from the AER on proposed capital expenditure, while Rule 65 allows the pipeline owner to seek a variation to its access arrangements during the period. These provisions have not been utilised in the last two access arrangement periods and some have suggested this is because the demand for the investment has not been acute enough to require it the use of these provisions. However, we have not yet been able to confirm whether this is the case or if there is something else that discourages the use of these provisions.

Given the costs and other adverse effects that delayed investment can impose on market participants, the Commission intends to consider whether the regulatory arrangements and market carriage model are providing for an appropriate allocation of risks and timely and efficient investment in the DTS in further detail in the DWGM Review. In doing so, we intend to consider:

- the materiality of the issue;
- the efficiency of the regulatory framework as a substitute for market-led investment; and
- potential options to address the issue, which could include introducing some form of transmission rights into the DTS and/or making changes to the regulatory framework (see section 4.5).

4.4 Efficient trade and movement of gas between jurisdictions

Notwithstanding recent investments to allow for greater volumes of gas flow between jurisdictions, concerns have been raised about a number of specific constraints on Victorian exports, some of which stem from interoperability issues between the market and contract carriage models. Concerns have also been expressed about the effect that the operation of two pipeline carriage models may have on the efficient trade and movement of gas, with some stakeholders suggesting the adoption of a single pipeline carriage model throughout eastern Australia.

These two issues are explored in the remainder of this section.

4.4.1 Constraints on exports out of Victoria

With more gas from the Cooper Basin expected to be directed to the LNG facilities in Queensland and the remainder of south eastern Australia expected to become more dependent on gas supplies from Victoria, it is relevant to consider whether the interaction between the market and carriage models or other market design factors may be impeding the efficient trade and movement of gas out of Victoria.[131]

131 As far as we can ascertain, there are no problems injecting gas into Victoria via Culcairn.

Observations from previous reviews

In the Scoping Study, stakeholders cited a number of constraints on the ability of shippers to export gas from Victoria via the DTS, including:

- difficulties that shippers had previously obtaining AMDQ for exports via Culcairn, which had resulted in exports being more susceptible to the risk of curtailment;
- the cost and complexities of having to participate in the DWGM for those shippers that just want to export gas; and
- constraints on exporting gas from the Gippsland and Bass basins to South Australia.[132]

Stakeholder submissions

A number of stakeholders noted the steps that have been taken in the last two years by APA and AEMO to address some of the concerns that were raised in the Scoping Study about the ability to export gas via Culcairn, which have involved:[133]

- expanding the northbound export capacity of the Interconnect; and
- amending the Wholesale Market AMDQ Procedures to enable AMDQ at a system withdrawal point (eg Culcairn) to be aligned with the firm capacity rights on an interconnected pipeline (eg the MSP) for the purposes of any withdrawal tie-breaker.[134]

While these steps have been taken, APA expressed some concerns about:

- the potential for contracted AMDQ capacity at Culcairn to be "eroded" over time; and
- the way in which AEMO makes gas supply and allocation decisions when the security of the system is threatened, which results in exports being at greater risk of curtailment than demand within Victoria.[135]

Origin Energy voiced similar concerns to APA about the withdrawal capacity at Culcairn being directly affected by demand in the remainder of the DTS and exports being "more susceptible to curtailment than other forms of demand."[136] Santos also

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132 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 91.

133 APA, Discussion Paper submission, 26 March 2015, pp. 14-15, AGL, Discussion Paper submission, 24 March 2015, p. 5, Origin Energy, Discussion Paper submission, 26 March 2015, p. 3 and APGA, Discussion Paper submission, March 2015, p. 34.

134 In amending these procedures, AEMO noted that the change would promote the efficient operation of the interface between the DWGM and interconnected facilities by allowing scheduling in the DWGM to align with firm contractual rights on interconnected contract carriage pipelines. AEMO, Notice to Participants of AEMO's Decision on Making the Wholesale Market AMDQ Procedure, 10 June 2014.

135 APA, Discussion Paper submission, p. 15.

136 Origin Energy, Discussion Paper submission, p. 3.

expressed concerns about the curtailment risk faced by shippers seeking to export gas via Culcairn and noted this risk was particularly high in winter.[137]

The curtailment issue was also touched on by some other stakeholders, who noted that while AEMO is required by the Victorian Gas Load Curtailment and Gas Rationing and Recovery Guidelines to consider whether an exporting party has an alternative source of supply before curtailing them, this may not occur in practice. Stakeholders added that the guidelines in their current form do expose exports to a greater risk of curtailment than other loads that are of a similar nature but are located in Victoria.

While most of the submissions focussed on exports via Culcairn, a small number of stakeholders also noted there are constraints on exporting gas from:[138]

- The Gippsland or Bass basins to South Australia which include:
  - physical constraints on the DTS, which limit the volume of gas that can be transported from the Gippsland and Bass basins across the DTS during peak periods;
  - differences between the pressure of the DTS and the SEA Gas Pipeline, which may give rise to additional pressure service costs; and
  - contractual constraints on the SEA Gas Pipeline, with all existing capacity on this pipeline currently contracted.
- The Gippsland basin into NSW via the EGP, because all the capacity on the EGP is currently contracted.

AEMC's Stage 1 findings

We note that many of the constraints on exports via Culcairn cited in the Scoping Study have been alleviated through investment, AEMO procedure changes and other measures implemented by APA and shippers to overcome other hurdles posed by the DWGM and the interaction between the two models.

These changes are expected to result in greater volumes of gas being exported via Culcairn in 2015. However, the Commission is aware that there are a number of other market design and interoperability issues that may impede the efficient trade and movement of gas between Victoria and other jurisdictions over time, including:

- The potential for contracted AMDQ capacity at Culcairn to diminish ("erode") over time as demand in the remainder of the DTS increases (ie because changes in demand in other parts of the meshed network affect capacity elsewhere in the system), which may result in either less exports over time, or the DTS capacity having to be continuously expanded to maintain contracted AMDQ capacity.[139]
- The costs and complexities of having to participate in the DWGM for shippers that just want to export gas out of Victoria, which may discourage exports via the DWGM, even if that is the optimal transportation route.

137 Santos, Discussion Paper submission, p. 6.

138 See for example, Adelaide Brighton, Discussion Paper submission, p. 4, Alinta, Discussion Paper submission, p. 8 and Epic Energy, Discussion Paper submission, p. 4.

139 Note that this issue does not appear to be unique to export related capacity expansions, rather it appears to be an issue for most expansions that occur within the meshed network.

- The curtailment arrangements in the DWGM,[140] which provide for the following in the event of a curtailment that is required to resolve a threat to system security:[141]
  - (a) exports to customers outside Victoria that have an alternative source of gas supply are to be curtailed ahead of their counterparts in Victoria; and
  - (b) exports to customers outside Victoria that do not have an alternative source of supply are to be curtailed in the same order as their counterparts in Victoria.[142]

While the curtailment arrangements appear appropriate from a system operation perspective, it is possible that they may discourage shippers that have access to alternative sources of supply from exporting gas through the DWGM even if that is the optimal export route. The Commission also understands from stakeholder submissions that when the system is under threat, there may be a tendency to treat all exports as curtailable, irrespective of whether or not they have an alternative source of supply.

Given the potential for these market design and interoperability factors to impede the efficient trade and movement of gas out of Victoria, we are of the view that there would be merit in investigating these issues further in the DWGM Review.

In terms of the constraints on exports of gas from the Gippsland and Bass basins into South Australia, it is unclear at this stage whether there is a significant amount of unmet demand for such exports at present, given gas can be supplied into South Australia from various fields in the Otway Basin. Nevertheless, we are of the view that the framework should not impede such flows should it become economic to export gas from Victoria to South Australia and will consider this potential constraint further in the DWGM Review.

4.4.2 Operation of two carriage models and potential for a single model

Before examining the issues that have been raised in earlier reviews and stakeholder submissions about the operation of two pipeline carriage models in eastern Australia and the potential for a single pipeline carriage model, it is worth setting out the perceived strengths and weaknesses of these two models.

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140 Under AEMO's Gas Load Curtailment and Gas Rationing and Recovery Guidelines, exports are listed in the second category of customers (ie, after Tariff D customers with either no AMDQ or that have used in excess of their assigned AMDQ) that will be constrained off, subject to "alternative gas supplies being available to export gas customers in the same categories as specified in the curtailment tables that have not been curtailed". While not well expressed, this provision appears to provide for export customers that have another source of supply, or would otherwise fall into the second category of customers (ie, gas fired generators or customers with an interruptible supply contract), to be in the second group of customers to be curtailed. Export customers that only obtain gas from Victoria and do not otherwise fall into the second category of customers, on the other hand, should be curtailed in the same order as Victorian customers.

141 AEMO, *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*, 13 May 2010.

142 For example, a gas fired generator located in NSW that is supplied with gas via Culcairn should be treated in the same manner as a gas fired generator in Victoria

Strengths and weaknesses of the market and contract carriage models

Both the market and contract carriage models have strengths and weaknesses.[143] For example, the market carriage model is said to promote both the efficient use of the DTS (ie through the operation of the DWGM) and dynamic efficiency in other markets (ie because it reduces barriers to entry), and circumvent the need for any secondary pipeline capacity market. The market carriage model may not, however, promote efficient and timely investment in the DTS because investment decisions are driven by regulatory processes rather than being market-driven (ie because shippers cannot access firm capacity rights and are therefore unwilling to fund expansions).[144]

The contract carriage model, on the other hand, is said to:

- promote efficient investment in the pipeline and a better allocation of investment risks, because shippers can secure firm access rights to any capacity expansions they fund, and are in a better position to manage long term investment risk through commercial arrangements with gas producers and/or end-users; and
- allow more bespoke transportation and storage services to be offered to shippers than those available under the market carriage model.

The contract carriage model may not, however, promote the efficient use of the pipeline when there is contractual congestion. Whether or not a contract carriage pipeline is utilised in the most efficient manner will depend on whether:

- firm capacity rights can be readily traded;
- parties have the incentive and ability to trade contracted but unutilised capacity (secondary capacity); and
- the transaction and coordination costs associated with entering into such a trade.

At different points in time the strengths and weaknesses of these two models can become more or less important. For example, as capacity constraints emerge on a market carriage pipeline the effect of any delays in investment brought about by the fact that investment is regulatory driven rather than market driven become more acute. Similarly, when a contract carriage pipeline is fully contracted but not fully utilised the effect of any constraints on access to spare capacity become more acute.

143 See for example, K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, pp. 112-113, Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, pp. 56-58 and Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, pp. 117-120.

144 This is because: the gas spot price facilitates access to the DTS by those who value access most highly; and use of the pipeline is unencumbered by contract capacity rights, which avoids problems associated with capacity trading, including difficulties in defining capacity and the potential exercise of market power by incumbent shippers or the pipeline owner. Note that because the DTS is operated on an open access basis there is also no scope for capacity hoarding.

Observations from previous reviews

In the Scoping Study stakeholders were asked about the potential for different pipeline carriage models to act as an impediment to exports from Victoria, but this was not considered a significant issue.[145] While no concerns were raised in the Scoping Study, the Victorian Gas Market Taskforce noted that different arrangements for access to pipelines across jurisdictions may "restrict the ability of parties to trade" and that more uniformity in this area would be "desirable".[146]

This issue was also touched on in the Victorian Department of Economic Development's 2014 Energy Statement, which noted the potential for a new access regime and a single pipeline carriage model to be implemented throughout eastern Australia that would provide for:[147]

- non-discriminatory access to pipelines;
- a single set of rules or standard contracts governing access to pipeline capacity;
- arrangements that promote secondary trading of pipeline capacity and the sale of unused capacity by pipeline owners;
- clear and transparent information on the availability of pipeline capacity; and
- rules governing congestion management and potentially congestion pricing.

In a similar vein to the Victorian Energy Statement, the Eastern Australian Domestic Gas Market Study noted the potential for a single pipeline carriage model to be applied throughout eastern Australia and suggested a review of the alternative carriage models be carried out by the AEMC, in consultation with AEMO. Elaborating on this further, the study noted:[148]

> "Open access to infrastructure under a market carriage model also involves trade-offs. While sometimes criticised for providing a weaker signal to investment, a strength of this model is that it may further encourage depth and liquidity in wholesale markets. Whether there is an alternative form of market carriage which could be more widely applied in Australia would require careful consideration and review...While the evidence does not suggest an immediate problem, given the changes in the east coast market it could be appropriate to review which model will best meet the future needs of the market."

The debate around which carriage model should be adopted if a single model is to be implemented throughout eastern Australia was also considered by the Productivity Commission. The Productivity Commission concluded that the relevant policy decision should not be viewed as a choice of one model over another. Rather, the "strengths and

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145 K Lowe Consulting, *Gas Scoping Study*, a report for the AEMC, July 2013, p. 118.

146 Victorian Government, *Gas Market Taskforce*, Final report and recommendations, October 2013, p. 37.

147 Department of State Development Business and Innovation (Victorian Government), *Victoria's Energy Statement*, 2014, p. 58.

148 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 101.

weaknesses of each model should be considered in the context of the expected future needs of Australia's gas markets."[149]

The Productivity Commission also noted that if the market carriage model was extended to the remainder of eastern Australia it could adversely affect investment at a time that it is required in the market and could also impose substantial costs on market participants if existing contractual rights had to be unwound.[150]

Stakeholder submissions

Stakeholders were divided on the question of whether a single pipeline carriage model should be implemented and if so, what that model should be. The advocates of a single pipeline carriage model included:

- Alinta, Stanwell, the MEU and Manufacturing Australia, who are of the view that there would be merit in considering whether the market carriage model (or a similar open access model) can be extended into the remainder of eastern Australia.[151]
- APA and APGA, who consider there would be merit in considering whether the contract carriage model can be extended into Victoria, or to certain segments of the DTS (eg the South West Pipeline, the Longford Gas Pipeline and the Interconnect).[152]

Importantly, none of these stakeholders consider that change is required immediately. Rather, they view the change as a longer-term option. In contrast to the advocates of a single pipeline carriage model, Jemena, AGL, EnergyAustralia and GDF Suez Australian Energy (GDFSAE) do not consider that a review into the relative merits of the contract and market carriage models or a single pipeline carriage model is required.[153] Elaborating further on this, AGL noted that:[154]

> "…commencing this debate will prove to be unnecessary and ultimately a distraction, particularly given that gas markets operate successfully with a combination of elements of both market and contract carriage. However, it is appropriate for the Commission to investigate points of interface between the two systems, to ensure gas can be wheeled from point to point without hindrance."

149 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, p. 118.

150 Productivity Commission, *Examining Barriers to More Efficient Gas Markets*, Research Paper, March 2015, pp. 105,119.

151 Alinta, Discussion Paper submission, 26 March 2015, p7, Stanwell, Discussion Paper submission, p. 7, MEU, Discussion Paper submission, p. 5 and Manufacturing Australia, Discussion Paper submission, p. 7.Alinta made it clear in its submission that this was a longer term policy option and not something that was required immediately, while Stanwell stated that such reform should only occur if the benefits outweigh the cost and "appropriate transition allowances" are used to "protect existing property rights. Alinta, Discussion Paper submission, p. 7, Stanwell, Discussion Paper submission, p. 7.

152 APGA, Discussion Paper submission, p.41. and APA, Discussion Paper submission, p. 30.

153 Jemena, Discussion Paper submission, p. 6, AGL, Discussion Paper submission, p. 7, EnergyAustralia, Discussion Paper submission, p. 3. GDFSAE, Discussion Paper submission, p. 6.

154 AGL, Discussion Paper submission, p. 7.

EnergyAustralia was of a similar view to AGL and noted that given the two models are likely to continue to coexist, it is important that the two systems interact effectively.[155]

While Origin Energy did not make any specific comments on this issue in its submission, the following observations were made in its submission to the Productivity Commission's recent review of the barriers to more efficient gas markets:[156]

> "… a review of the carriage models may be appropriate to support the continued development of the gas market. This review should not presuppose one model is better than the other and therefore that the objective of the review is a transition to the perceived better model. Instead it should focus on identifying the strengths and weaknesses of the two models and whether firstly, there is scope for consistency between the models and secondly, an evolutionary process to a single model is appropriate. An assessment of costs and benefits should also support any case for change."

AEMC's Stage 1 findings

As the discussion above highlights, neither the market carriage model nor the contract carriage model is perfect and a movement from one to the other is likely to involve significant efficiency trade-offs. Consequently, any consideration of a single pipeline framework would need to consider alternatives that may balance these trade-offs differently to the existing carriage models. A decision to implement a single pipeline carriage model is also likely to:

- give rise to significant implementation costs and risks;
- have a number of practical implications for capacity rights, system and market operation, regulation, investment, competition in the transmission segment and in upstream and downstream markets, all of which would have to be considered; and
- give rise to a considerable degree of uncertainty and disruption in the market, which the AEMC is particularly conscious of given the changes underway in the market.

It follows from these points that the benefits of implementing a single pipeline carriage model would need to be quite substantial for a decision to be made to proceed down this path.

To date, we have yet to see any compelling evidence to suggest that:

- the existence of both the market and contract carriage models is currently acting as a significant impediment to the trade and movement of gas between jurisdictions, although it may be affecting the efficiency with which gas is traded and moved between jurisdictions;[157] or

155 EnergyAustralia, Discussion Paper submission, p. 3.

156 Origin Energy, Submission to the Australian Eastern Domestic Gas Market Study, 2014, p. 6.

157 Support for this view can be found in the fact that exports from Victoria via the DTS are occurring and are expected to increase from mid-2015. It can also be found in the submissions received from stakeholders that are actually exporting gas or are involved in the export of that gas.

- the benefit of implementing a single carriage model would be substantially greater than the benefit that could be achieved by addressing the perceived deficiencies in the two pipeline carriage models.

That is not to say that there would not be value in investigating the options for a single pipeline carriage model further. However, in the AEMC's view, this should form part of the longer-term strategic development element in Stage 2 of the East Coast Gas Review and more immediate attention should be given to addressing:

- the secondary trading issues in the contract carriage model (see section 4.2);
- and the investment issues in the market carriage model (see section 4.3); and
- the interoperability issues between the two models (see section 4.4.1).

This approach is broadly consistent with the approach that has been advocated by stakeholders and will enable a more strategic and detailed review of the options and the costs and benefits associated with each option to be undertaken without adding additional uncertainty or disruption into the market at a time when it is undergoing significant structural change. As part of this review, the AEMC would expect to consider whether the proposed options fit within the existing third party access regime and if not, the changes that may be required in this area.

4.5 Regulatory framework

The third party access regime and access regulation provisions applying to transmission pipelines had its genesis in a series of COAG agreements in the 1990s, which culminated in the enactment of the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the Gas Code in late 1997. In mid-2008 the GPAL and Gas Code were replaced by the NGL and NGR. A brief overview of the third party access regime applying to transmission pipelines is provided in Box 4.2, while Appendix D contains further detail.

The manner in which the third party access regime and access regulation operate under the NGL and NGR is depicted in Figure 4.2. Before examining this figure, it is worth noting that the arrangements for obtaining access to the DTS are somewhat different to those set out in this figure because it is operated on an open access basis and users or prospective users do not enter into bilateral contracts with the service provider.

On the whole, the regulatory framework appears to have worked relatively well over the last 18 years and has been sufficiently flexible to deal with changing market conditions.[158] It also appears to have met many of COAG's original expectations for the regime, including supporting the efficient development and operation of an integrated pipeline network and promoting a competitive market for gas.[159] However, questions have been raised by some stakeholders about whether the regulatory framework is still

158 For example, with the advent of pipeline-on-pipeline competition in Sydney, Canberra and Adelaide, the regulatory status of the incumbent pipelines (the Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline System) has changed to reflect the reduced ability of these pipelines to exercise market power.

159 National Third Party Access Code for Natural Gas Pipeline Systems, November 1997, p. 1. Further detail on COAG's original expectations for the access regime can be found in Appendix D.

fit for purpose given the changes underway in the market and whether it can support any measures that may be required to improve:

- the efficiency with which pipeline capacity is allocated (section 4.2);
- the efficiency and timeliness of investment in the DWGM (section 4.3); and
- the efficient trade and movement of gas between jurisdictions (section 4.4).

These issues are explored in further detail below, which commences with an overview of the views expressed by stakeholders in submissions to the Discussion Paper.

Stakeholder submissions

The views expressed by stakeholders about the regulatory framework were quite diverse, with a number believing the framework is working as policy makers intended, while others are of the view that there are some gaps in the current arrangements. A number of stakeholders also noted the potential for more fundamental changes to the regulatory regime to support a greater degree of capacity trading, open access and/or investment.

Those stakeholders that consider the current framework is working as policy makers intended and are well placed to deal with the changes underway include APGA, APA and Jemena.[160] Santos also expressed a positive view on the regulatory regime:[161]

> "In the Australian context, we have seen a growth in the uncovered transmission pipeline networks, mainly due to the agility of the operators and shippers to work together to meet market demand. This shows that the market is working efficiently, shippers who have requirements to move gas around are contracting directly with pipeline operators to construct and expand pipelines directly. If there were no pipelines being built or expanded even though there was demand for it, that would be a concern, this however is not the case."

The MEU, on the other hand, expressed some concerns about:

- the relatively high threshold embodied in the criteria that must be satisfied for a pipeline to become covered (the "coverage criteria"), which it claimed "create a major hurdle to any objector;"[162] and
- the fact there are a number of pipelines servicing regional industries and communities that are unregulated even though they are the only pipeline servicing these areas.[163]

Adelaide Brighton also voiced some concerns about pipelines servicing regional industries and noted that in some areas of South Australia a retailer had been able to

160 APGA, Discussion Paper submission, p. 41, APA, Discussion Paper submission, p. 3 and Jemena, Discussion Paper submission, p. 1.

161 Santos, Discussion Paper submission, p. 7.

162 MEU, Discussion Paper submission, p. 7.

163 MEU, Discussion Paper submission, 2015, p. 7.

restrict the supply options available to customers by acquiring all the capacity on some regional pipelines and laterals.[164]

The following concerns about the regulatory framework were also raised by AGL in its submission to the Energy White Paper:[165]

> "In AGL's view, one key regulatory area requiring reform is better regulation of gas transmission network pricing. Even with increasing interconnection, the disparity of bargaining power between pipeline operators and shippers is leading to economically inefficient outcomes and negatively impacting market depth and liquidity...
>
> ...Most pipelines are 'uncovered', and not subject to economic regulation. While coverage, or the threat of coverage, theoretically operates as a constraint to pipeline operators in their commercial negotiations with shippers, pipeline coverage is actually hard to obtain and, once obtained, tends to lead to an access arrangement with only limited scope."

Those stakeholders that consider more fundamental changes to the regulatory framework may be required include:

- the Victorian Department of Economic Development, who suggested that a new access regime (or code) be applied to all pipelines in eastern Australia and provide for non-discriminatory access to pipelines and a range of other measures to facilitate more capacity trading (see section 4.2);[166]
- Arrow Energy, who advocated the adoption of a single regulatory regime that provides clear mechanisms for accessing capacity;[167]
- BHP Billiton, who noted that as consolidation and increased interconnectivity takes place in the transmission segment there is "potential for inefficient transportation market outcomes" under the current framework and suggested a more uniform approach to gas pipeline regulation be considered, similar to that which applies in the UK and the US;[168]
- Manufacturing Australia, who supported the extension of regulation to all transmission pipelines to "ensure equality of access";[169]
- the GLECMU, who advocated the adoption of a "single pipeline regulatory regime with clear links between revenue and market outcomes" if the existing investment arrangements are found to hinder market development;[170] and

164 Adelaide Brighton, Discussion Paper submission, p. 4.

165 AGL, Energy White Paper submission, Attachment 1, 4 November 2014, p. 11.

166 Department of Economic Development (Victorian Government), Victoria's Energy Statement, 2014, p. 58.

167 Arrow Energy, Discussion Paper submission, p. 6.

168 BHP Billiton, Discussion Paper submission, p. 3.

169 Manufacturing Australia, Discussion Paper submission, p. 7.

170 Group of Leading Energy Companies and Major Users, Discussion Paper submission, 30 March 2015, p. 3.

- Stanwell, who is of the view that the current framework "does not provide the right incentives for the efficient allocation of capacity or enough flexibility to promote an active short term market"[171] and suggested the existing framework be replaced with regulatory framework used in electricity.[172]

As to the view that the regulatory framework in gas should be the same as it is in electricity, GDFSAE made the following observation:[173]

> "A related issue, that is somewhat controversial, is contrasting the differences in transportation between gas and electricity. With the growing role played by a small number of pipeline players there is an open question as to the benefits of a single pipeline regulatory regime, notably with clear links between revenue and market outcomes. The alternative view is that pipeline investments are clearly underwritten by shippers and therefore already meet the needs of the market. GDFSAE cautions against this issue consuming the review but notes that a developed evidence and analytical base is required to aid a considered discussion in this area."

AEMC's Stage 1 findings

The Commission understands from the comments set out above that while the regulatory framework has worked relatively effectively to date, there may be some gaps in the current framework that warrant closer attention, particularly given the changes underway in the market and the increasing interconnectedness and concentration in this segment of the supply chain. We are therefore of the view that there would be value in considering as part of the Stage 2 East Coast Review whether:

- the regulatory framework is still fit for purpose and is likely to remain so into the future given the changes underway in the market and potential developments; and
- specific changes to the regulatory framework may be required to put in place measures that can improve the efficiency with which:
  - pipeline capacity can be allocated on contract carriage pipelines (eg measures to reduce the barriers to capacity trading and/or facilitate a more transparent and competitive market for secondary trading);
  - investment decisions can be made in the DWGM; and
  - gas can be traded and moved between and within jurisdictions (eg measures to address any interoperability issues between the market and contract carriage models).

In relation to some of the specific changes that may need to be made to the regulatory framework, the AEMC would expect that any changes that may be required to deal with the investment issues in the DWGM and/or the interoperability issues could be made within the confines of the existing regulatory framework. However, a decision to implement a new market based mechanism for secondary capacity trading (or other

171 Stanwell, Discussion Paper submission, 26 March 2015, p. 3.

172 Stanwell, Discussion Paper submission, p. 3.

173 GDFSAE, Discussion Paper submission, p. 7.

measures to reduce barriers to capacity trading) may require more extensive changes, particularly if the measure imposed access related obligations on pipeline owners. This is because under the current regulatory framework a pipeline can only be subject to access regulation if it is a covered pipeline.

Of the 27 transmission pipelines in eastern Australia, only 5.5 are currently covered[174] and the remainder are unregulated.[175] As such, a decision to implement a mandatory trading obligation on pipeline owners, the oversell buyback regime or a new open access regime could only be applied to the 5.5 pipelines that are currently covered. While it is possible under the NGL for unregulated pipelines to become covered,[176] this can only occur if the pipeline satisfies all the coverage criteria (see 4.2). The threshold for coverage is currently quite high, so the prospect of more pipelines becoming covered appears quite low.[177]

The coverage threshold embodied in section 15 of the NGL is consistent with the threshold for declaration under Part IIIA of the CCA and that the height of the threshold has, as noted by both the Productivity Commission and the Competition Policy Review Panel, been designed to confine the application of the access regulation to:[178]

> "…exceptional cases, where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third-party access."

It also appears that the threshold for coverage could become even higher if the Competition Policy Review Panel's suggested amendments to Part IIIA of the CCA (see Box 4.6) are accepted by the Australian Government, and the Energy Council were to decide to make equivalent changes to the NGL.[179]

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174 Of the 5.5 pipelines that are covered, three are subject to full regulation (the Roma to Brisbane Pipeline, the DTS and the Central Ranges Pipeline) and 2.5 are subject to light regulation (the Carpentaria Gas Pipeline, the Central West Pipeline and the Moomba to Sydney Pipeline from Marsden to Sydney (the remaining half of the Moomba to Sydney Pipeline is unregulated)).

175 Appendix D provides further detail on why coverage has been revoked on a large number of pipelines.

176 The one exception to this is pipelines that are subject to a 15 year no coverage determination.

177 The threshold is high because all four criteria must be satisfied and criterion (a) requires access to promote a material increase in competition in another market.

178 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review* Final Report, March 2015, p. 431 and Productivity Commission, *National Access Regime*, 25 October 2013, p. 2.

179 Whether or not a higher threshold for coverage is appropriate is something that would need to be carefully considered by the COAG Energy Council, particularly given: the concerns raised by both the MEU and AGL about the height of the current threshold and the extent to which the threat of regulation really does constrain a pipeline owner's behaviour; and the effect that the increasing degree of concentration and interconnection in the transmission segment and the movement away from the traditional point-to-point services (which together with the increasing interconnection may give rise to greater network externalities) may have on the ability that some pipeline owners have to exercise market power.

Box 4.6 Competition Policy Review Panel – Changes to Part IIIA

The declaration criteria in Part IIIA currently state the following:

(a) access (or increased access) would promote a material increase in competition in at least one other market (whether or not in Australia), other than the market for the service;

(b) it would be uneconomic for anyone to develop another facility to provide the service;

(c) the facility is of national significance, having regard to: (i) the size of the facility; (ii) the importance of the facility to constitutional trade or commerce; or (iii) the importance of the facility to the national economy;

(d) [repealed];

(e) access to the service: (i) is not already the subject of an effective access regime; or (ii) is subject to an effective access regime but the NCC believes that, since the Commonwealth Minister's decision was published, there have been substantial modifications of the access regime or of the relevant principles set out in the Competition Principles Agreement; and

(f) access (or increased access) would not be contrary to the public interest.

The Competition Policy Review Panel recommended the following changes to these criteria, all of which are expected to raise the declaration threshold:

- Criterion (a) should require that access on reasonable terms and conditions through declaration promote a *substantial* increase in competition in a nationally significant dependent market. In suggesting this change, the Panel stated:

  "The burdens of access regulation should not be imposed on the operations of a facility unless access is expected to produce efficiency gains from competition that are significant. This requires that competition be increased in a market that is significant and that the increase in competition be substantial."

- Criterion (b) should require that it be uneconomic for anyone (other than the service provider) to develop another facility to provide the service and a "privately profitable" test should be applied rather than the 'natural monopoly' test. The practical effect of this interpretation is that if it can be established it would be privately profitable to duplicate the asset, criterion (b) would not be satisfied, even though it may not be efficient to duplicate.

- Criterion (f) (equivalent to criterion (d) in the coverage criteria) should require that access on reasonable terms and conditions through declaration promote the public interest. This differs from the current drafting which states that access (or increased access) to the services would not be contrary to the public interest.

Source: Harper, I., et al., *Competition Policy Review Final Report*, March 2015, pp. 73-74.

It may not therefore be possible to implement some of the measures stakeholders have suggested unless more fundamental changes are made to the third party access regime by, for example, introducing an alternative form of regulation that can be applied to all pipelines, irrespective of whether they satisfy the coverage criteria, or amending the coverage criteria.

The preceding discussion should not be construed as the Commission having formed a view that the access regime in the NGL needs to change at this stage. Rather, it is intended to highlight the constraints within the existing regulatory framework that would need to be considered when deciding what, if any, measures should be implemented to facilitate more capacity trading. While it is possible that these constraints could, with the agreement of COAG be relaxed, or an alternative regulatory regime put in place, we are aware that this would constitute a fundamental change in the current arrangements and would need to be carefully considered given both:

- the principles set out in COAG's Competition Principles Agreement; and
- the views that have recently been expressed by the Productivity Commission,[180] and the Competition Policy Review Panel[181] about the circumstances in which access regulation should be applied.

The Commission is also cognisant of the fact that:

- regulation is a second best option to competition and that to the extent that a greater level of capacity trading could be achieved by reducing the barriers to shippers competing with pipeline owners for the provision of spare capacity, this should be pursued; and
- regulation is neither perfect nor costless, and that to the extent that the same outcomes can be achieved through industry led initiatives this should be pursued.

The AEMC intends therefore to consider any proposed changes to the regulatory framework (including any changes required to address investment issues in the DTS or improve the interoperability of the market and contract carriage models) having regard to both the NGO and the COAG's Principles of Best Practice Regulation, which in short, require:

- the market failure[182] or deficiencies in the existing framework to be clearly identified; and
- a rigorous and transparent assessment of the set of feasible policy solutions (including regulatory, self-regulatory, co-regulatory and non-regulatory options) to be conducted.

180 Productivity Commission, *National Access Regime (2013)*, 25 October 2013, p. 2.

181 Harper, I., et al., *Competition Policy Review* Final Report, March 2015, pp. 73-74.

182 The term 'market failure' is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

5 Short Term Trading Market

Box 5.1 Summary of findings and recommendations

In 2006 when the STTM was conceived, the only wholesale spot market for gas was the DWGM. At the time, governments identified the need to increase market transparency and provide participants with additional options for pricing imbalances and trading incremental gas outside of bilateral contracts.

The Adelaide and Sydney STTM hubs are generally regarded by participants as providing an effective gas balancing service and means of facilitating trade at demand centres, although views on the usefulness of the Brisbane STTM are mixed. Nonetheless, the prevalence of bilateral contracts and the mandatory nature of the STTM, results in only a small portion of total gas "traded" on the market benefiting from the centralised market arrangements.

Complexities associated with the STTM design may impose disproportionate operational and administrative costs on participants. Additionally, the differences between the two compulsory facilitated markets on the east coast – the STTM and DWGM – represent an added level of complexity for firms wishing to operate across jurisdictions, even though their practical roles as gas balancing markets are similar.

The emergence of the gas supply hub, coupled with the structural change in supply and demand resulting from the advent of LNG exports in Queensland, suggest it is an opportune time for reflection on the role of the STTM in the broader east coast gas market, as well as the facilitated markets more generally. In particular, we consider there is merit in considering whether:

- the originally stated STTM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
- if not, whether the objectives and design of the STTM need to be re-focussed, taking into account developments in the broader east coast market and the STTM's role alongside other facilitated markets.

We will progress these issues as part of Stage 2. We also outline our preliminary views on Stage 1 recommendations, which represent "no regrets" changes where implementation can begin immediately.

Taking into account views in submissions and analysis in this chapter, the AEMC considers harmonising gas day start times are likely to reduce transaction costs and might therefore promote the NGO. As such, the final Stage 1 recommendations of this review may include a rule change that the Energy Council could submit to align gas day start times.

5.1 Market overview

This section provides an overview and background to aspects of the STTM relevant to the issues considered throughout this review. It covers the original objectives for establishing the STTM hubs, key design features as well as how the markets operate in practice. A detailed appendix on how the design of the STTM is set out in Appendix E.

Market objectives

The Short Term Trading Market (STTM) was implemented in Adelaide and Sydney in September 2010 and Brisbane in December 2011. It was part of a package of reforms by the Ministerial Council on Energy (MCE), which also included the National Gas Services Bulletin Board, Gas Statement of Opportunities and the establishment of a national gas market operator.[183]

In recommending the establishment of the STTM, the Gas Market Leaders Group, an industry-led body established by the MCE, set out the following objectives for the market:[184]

- Establish a mandatory price based balancing mechanism for gas delivered and withdrawn from defined market hubs, replacing existing gas balancing arrangements at delivery points within hubs.
- Facilitate gas trading on a daily basis at market driven short-term prices.
- Provide pricing signals and facilitate secondary trading between shippers and users, for gas-fired generators, for trading over interconnecting pipelines between hubs, and to facilitate greater demand side response.[185]

Taking into account these objectives, the STTM was designed as a day-ahead market for the trade of wholesale gas between transmission and distribution pipelines. STTM hubs are primarily used for:

- providing a competitive service for participants to manage daily gas imbalances; and
- commodity trading.

Market design

STTM hubs in Adelaide and Sydney are supplied by two transmission pipelines, while the Brisbane STTM hub is supplied by one transmission pipeline, as shown in Figure 5.1. The underlying contractual arrangements (excluding prices) between transmission pipeline operators and shippers, and between distribution networks and users, must be registered in the STTM with AEMO.

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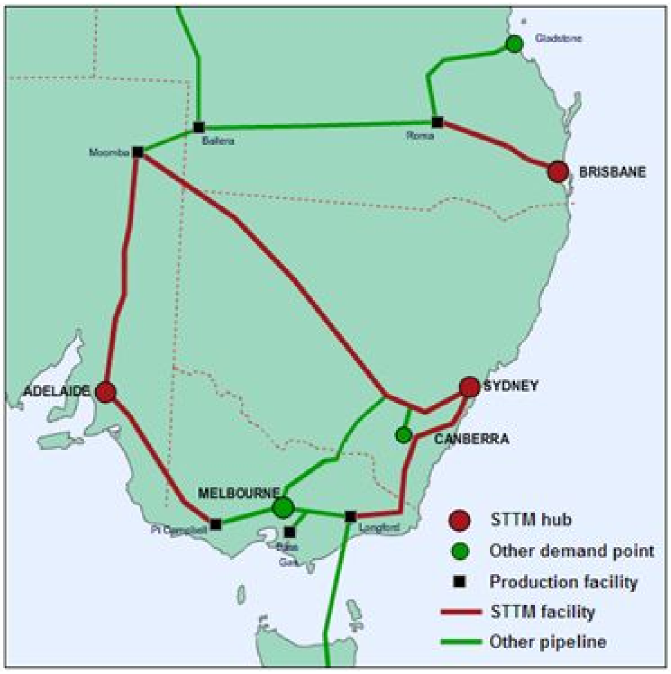
183 The national gas market operator became AEMO, which assumed the functions of the state-based Gas Market Company, Retail Energy Market Company and gas functions of the Victorian Energy Market Corporation.

184 Gas Market Leaders Group 2006, *National Gas Market Development Plan,* Gas Market Leaders Group report to the Ministerial Council on Energy, Canberra, p. 23.

185 "Shipper" is the term used for a participant that transports gas through a transmission pipeline between production and demand centres.

Unlike the DWGM, AEMO manages the market but has no role in operating the pipeline and storage infrastructure, which is operated and scheduled by the infrastructure owners.

Figure 5.1 STTM hubs are located at Adelaide, Brisbane and Sydney



Source: AEMO.

Due to the physical characteristics of natural gas, and the time it takes to flow through transmission pipelines, nominations by gas users are made to producers and pipeline operators the day before users require the gas.[186] Given this, and the objectives of the market, the STTM design was based around two broad elements:

- **an ex ante commodity market** – where supply and demand is matched for the following day and an ex ante price is determined by the market operator;[187] and
- **an on-the-day balancing mechanism** – to account for differences on the gas day between the supply and demand schedules determined in the ex ante market and to ensure system security is maintained.[188]

The ex ante commodity market is where shippers offer to supply gas and users bid to purchase gas for delivery the following day. Offers and bids can be submitted to AEMO up until 12.00pm the day before gas day in Adelaide and Sydney, and up until 1.30pm in Brisbane.[189]

186 In Victoria, gas is typically produced and delivered within 6 – 8 hours due to the close proximity of the gas fields to demand centres. In contrast, gas delivered from the Moomba into Sydney can take 2 – 3 days.

187 In this context, ex ante refers to transactions that occur the day before a commodity is traded.

188 In this context, system security refers to transmission and distribution pipelines operating within their pressure tolerances.

189 The variation in timing is due to differences in gas day start times at the hubs. The Brisbane hub operates from 8am EST while Sydney and Adelaide operate from 6.30am EST.

Transactions in the ex ante market can be separated into two categories. The first and most common relates to the same entity selling gas into the hub and purchasing from the hub. This occurs due to the compulsory nature of the STTM and is discussed further below. The second category is where two different entities buy and sell gas in the ex ante market, as occurs in a traditional commodity market.

The on-the-day balancing mechanism is the second design element of the STTM and arguably its primary role in the broader east coast gas market. Without the STTM or another form of balancing market, pipeline operators would balance the system under a service negotiated as part of bilateral contracts with their customers.

Market Operator Service (MOS) is the STTM's on-the-day balancing mechanism and is essentially a pipeline capacity service. Shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand or supply gas if flows to the hub are below demand (also known as bank and borrow or park and loan). MOS is procured through a competitive process each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges, which are discussed in detail in section E.2.4.

Market operation

A range of physical gas market participants, such as retailers, gas-fired generators and large industrial users transact through the STTM, although no financial institutions are currently registered at any of the STTM hubs. The number and type of participants currently registered at each hub is set out in Table E.4.

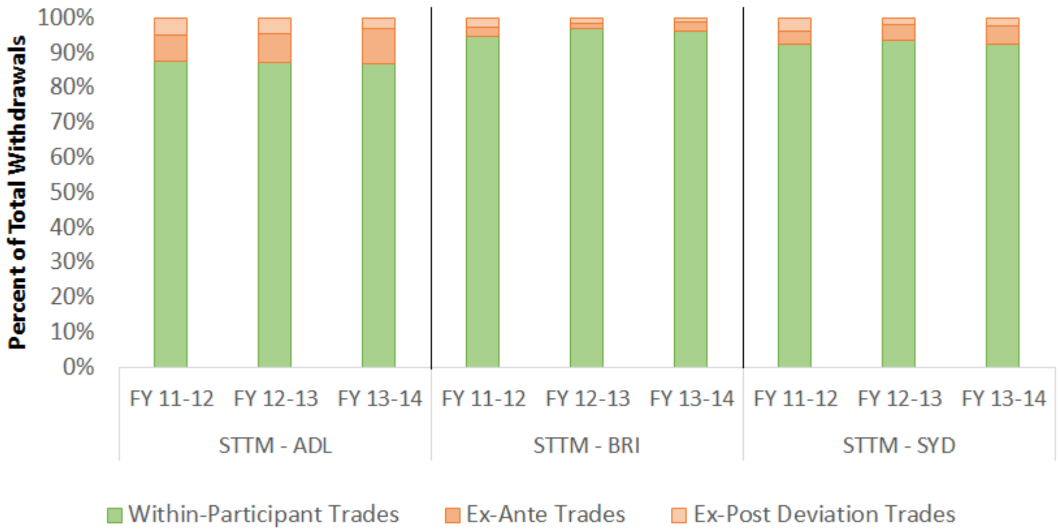
The STTM hubs have largely provided an effective and competitive gas balancing service. They have also contributed to price transparency on the east coast, noting that before the STTM hubs were implemented the DWGM was the only source of wholesale gas price transparency. A number of participants have also found the STTM useful as a way of initially entering the gas market before committing to bilateral gas supply and transportation agreements.

As the majority of gas bought and sold on the east coast is through long term bilateral contracts outside of the STTM, participants are generally both shippers and users.[190] This is because all gas delivered to the hub is required to be transacted through the STTM, which results in the same entity selling gas into the ex ante commodity market and purchasing it back each day.

Figure 5.2 categorises STTM transactions into three types: within-participant trades, ex ante trades and ex post deviation trades. The graph shows that at least 85 per cent of transactions across all STTM hubs are within-participant, while for Brisbane over 95 per cent of trades are within-participant. Most ex ante trades have occurred in Adelaide, with the least occurring in Brisbane.

190 STTM shippers deliver gas to be sold into the market and STTM users buy gas for consumption.

Figure 5.2 Majority of transactions on the STTM are within-participant



Source: AEMO. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities at the start of the gas day; ex post deviation trades is deviations during the gas day.

As the majority of trades that occur on the STTM are within-participant, the level of trading liquidity between different entities across the three markets is generally low.[191] In addition to the high level of bilateral contracting, trading between different entities is likely to be limited due to the STTM hubs being physically located at the end of long transmission pipelines, which restricts the ability to ship gas into other markets, and indicates that these markets are unlikely to develop into liquid commodity markets.

Consequently, the ex ante price is unlikely to be a robust reference price that market participants can trade around and, as discussed in section 5.2.2, is generally considered to reflect short term imbalances between daily gas requirements and long term contract positions. However, we note that it is not clear whether providing a robust reference price was the intention of the original market design, where the focus was on facilitating short term trading of imbalances and establishing price transparency.

5.2 Key issues in the STTM

A number of reviews have been carried out over the past 24 months which that have identified potential issues with the STTM design. These include the:

- ESAA assessment of the east coast gas market that was prepared by Deloitte in May 2013;[192]
- AEMC's Scoping Study that was published in July 2013;[193] and
- Commonwealth Department of Industry and the Bureau of Resource and Energy Economics (BREE)'s Eastern Australian Domestic Gas Market Study, which was published in January 2014.[194]

191 Liquidity in this context is defined as the ability to buy or sell gas without causing a major change in price and without incurring significant transaction costs.

192 See: http://www.esaa.com.au/policy/east_coast_gas_market_reform_1_1

193 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Gas-market-scoping-study

AEMO has also completed two reviews since the commencement of the market as part of its obligations under the NGR. The first review related to the operation of the market, including MOS, settlement surplus and shortfall, and deviation and variation parameters, and was published on 30 March 2012.[195] This review led to AEMO submitting a number of rule changes to the Commission around MOS, deviations and settlement surplus and shortfall.

The second review considered the merits of transitioning the market to intraday trading and looked at the appropriateness of the market price cap and cumulative price threshold. This review was published on 21 December 2012 with AEMO recommending not to progress intraday trading or additional hubs at that time.[196]

Since commencement of the STTM in September 2010, AEMO has submitted eleven rule changes to the Commission for consideration. These are summarised in Appendix E.3. While the NGL allows any interested party to submit a rule change proposal relating to the STTM, to date industry has progressed proposed changes through AEMO's consultative forums.[197]

Matters considered in this chapter

The following sections of this chapter set out the key issues that have been identified in the STTM, drawing on observations from previous reviews, submissions to this process and analysis by the Commission. The issues are presented in three categories:

1. STTM complexity and the value of the ex ante price signal (considered in section 5.2.1).
2. Inability to manage risk (considered in section 5.2.2).
3. Transaction costs associated with value adding market functions (considered in section 5.2.3).

5.2.1 STTM complexity and the value of the ex ante price signal

This section outlines the complexities associated with operating in the STTM. These complexities extend to parties operating across the STTM and DWGM.

In this section we also cover price transparency in the STTM, including the value of the ex ante price signal to market participants, how it is set and what prices represent in terms of supply and demand.

Complexities associated with the STTM

As discussed above, the STTM was designed to facilitate commodity trading and a competitive on-the-day balancing service between transmission and distribution pipelines. The complexities associated with a market designed to provide both of these functions may be one of the reasons behind the high per GJ transaction costs associated

194 See: http://www.industry.gov.au/Energy/EnergyMarkets/GasMarketDevelopment/Pages/EasternAustralianDomesticGasMarketStudy.aspx

195 AEMO, *STTM Operational Review and Demand Hubs Review*, Final Report, 30 March 2012.

196 AEMO, *STTM Intraday Review*, Final Report, 21 December 2012.

197 NGL, section 295(1).

with operating in and administering the market, relative to the volume of trades that benefit directly from the imposition of the market.

We note that complex energy market designs may, depending on the objectives of the market, be unavoidable. Electricity and natural gas are commodities that both exhibit unique physical characteristics that influence the means of exchange. However, the level of complexity and resultant costs should be minimised, while the value a centralised market provides to its participants should be greater than its costs.

Some of the complexities inherent in the design of the STTM manifest in the number of potential price risks that participants could be exposed to. These include:

- ex ante price;
- pipeline capacity payment and charge;
- deviation payment and charge - calculated based on either the ex ante price, ex post price, MOS increase or decrease price, or the high or low contingency gas price;
- variation payment and charge - calculated based on a sliding scale on a quantity and percentage basis;
- contingency gas price; and
- settlement surplus and shortfall.

While the ex ante price is determined the day before the gas day, the other price risks are generally a function of what occurs during the gas day. A detailed overview of the on-the-day balancing mechanism is set out in Appendix E, with further analysis of risk management in the STTM outlined below in section 5.2.2.

In addition, differences between the STTM and DWGM may be acting as a barrier for firms looking to enter both markets; or contributing to additional costs for participants who currently operate in both of these markets. As the STTM and DWGM are both primarily used by shippers for balancing and incremental commodity trades, there is likely to be value in considering measures to harmonise aspects of the market designs.

Some of the key differences between the STTM and DWGM include:

- market terminology;
- start time for gas trading days (6.00am in the DWGM, 6.30am in the Sydney and Adelaide STTM hubs and 8.00am in the Brisbane STTM hub);
- trading periods (DWGM has 5 intra-day trading periods, while the STTM operates on a day-ahead basis with market schedule variations for intraday renominations);
- market price caps and cumulative price thresholds (market price cap is $800/GJ in the DWGM and $400/GJ in the STTM); and
- separate prudential requirements.

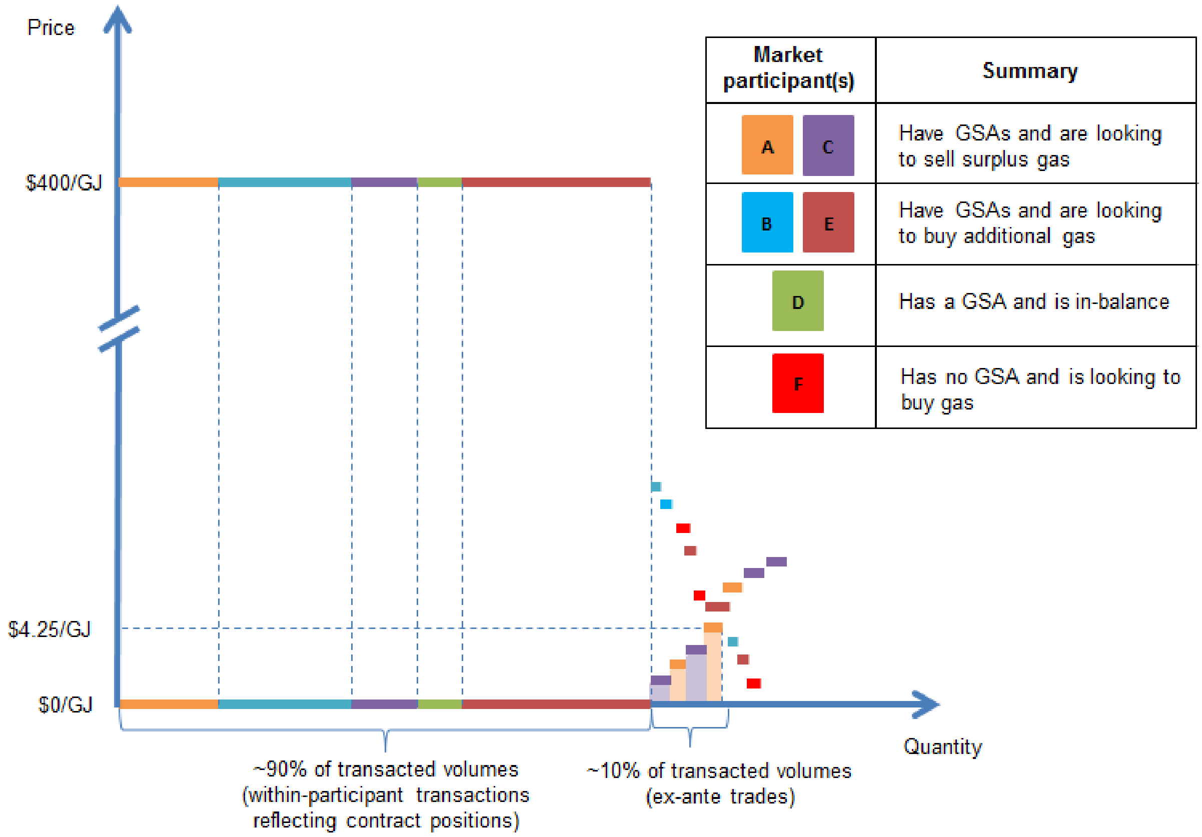
Value of STTM ex ante price signal

As discussed above, the current STTM market design requires that all gas shipped to and/or withdrawn from the hub is transacted through the market. Since the majority of trades occur within-participants, the level of liquidity underpinning the market price in the STTM can be considered to be low. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times.

Figure 5.3 presents a stylised example of the supply and demand conditions inherent in the ex ante DWGM price signal and how they contribute to an overall low level of illiquidity in the market. Each coloured segment of the curves represents a particular bid or offer price and volume pair by a market participant (there are six assumed market participants, each represented by a different colour). Price is represented on the vertical axis, while volume is represented on the horizontal axis (the length of each coloured segment denotes how much volume a participant is willing to buy or sell to the market at that price). The overall positions of each market participant are summarised in the box next to the figure.

The quantities of gas participants require to meet contractual obligations (the flat sections of the supply and demand curves) can be thought of as representing absolute illiquidity since market participants require these volumes to fulfil their contractual obligations (they are price inelastic). As such, we would expect market participants to submit bids and offers for these volumes that ensure they are scheduled (these bids and offers are assumed to be $400/GJ (the market price cap) and $0/GJ, respectively, in the example below). The remaining bids and offers are essentially those that set the market price in the STTM.

Figure 5.3 **Stylised example of the supply and demand conditions inherent in the ex ante STTM price signal**



Source: AEMC analysis.

Since most participants endeavour to align their bids and offers so as to not be exposed to the STTM ex ante price risk (as the green participant in Figure 5.3 has done), the remaining bids and offers reflect daily imbalances between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to between 5 and 10 per cent of total volumes.

Consequently, the observed STTM market price is susceptible to both a small volume of trades and a small number of market participants.

Stakeholder submissions

STTM (and DWGM) complexity was raised in almost all submissions. In order to summarise stakeholders' views, we have separated the issues into four categories:

1. Complexity of the markets.
2. Consistency between market parameters.
3. Future development of the facilitated markets.
4. The value of the STTM ex ante price signals.

Complexity of the markets

The Major Energy Users (MEU) suggest that the use of the facilitated markets for purchasing gas on a short term basis is "very limited due to the complexity of the gas markets and the very high adjustments made ex post".[198] Similarly, Origin Energy agrees that the STTM and DWGM are complex to operate in and a key principle for this review should be to simplify the unnecessarily complex elements of the markets.[199]

GDFSAE considers the existence of multiple hub designs create complexity and inefficiencies that are likely to discourage greater participation outside of retailers in major demand centres. It notes that the STTM and DWGM require more development to manage challenges facing the market to facilitate the optimal level of trade outside of bilateral contracts.

GDFSAE considers that the development of these markets has not progressed due to the complicated nature of the hubs, which require significant work to progress even minor operational matters, and the consultative forums chaired by AEMO, which are unable to regularly unify behind individual reforms.[200]

QGC notes that multiple market designs make trading complex, inefficient and costly for participants. They also note that due to the operation of specific design features and the size of the markets, prices published by the STTM do not always impact the underlying supply and demand for gas.[201]

The Group of Leading Energy Companies and Major Users (GLECMU) noted that resolving identified issues with existing trading hubs is a necessary pre-condition to the development of an integrated gas market. They note that multiple market designs make trading complex and inefficient for participants, with each market characterised by "specific and enduring limitations". Further, hubs should be designed to facilitate maximum participation and promote liquidity.[202]

While the APGA consider the STTM hubs provide a liquid balancing mechanism and still remain relevant to the Energy Council's vision, they note there is an important question around whether they are overly costly and complex for this role. APGA suggests there is a question around the STTM's ongoing role given the advent of multiple supply hubs and capacity trading.[203]

APA considers that, while the STTM hubs have provided an effective and competitive gas balancing service, there appears little evidence of the STTM hubs increasing the number of retailers due to significant exposures that can result from the market. APA notes that the STTM is unnecessarily complex for the primary gas balancing function that they perform and this drives significant market costs.[204]

198 MEU, Discussion Paper Submission, p. 4-6.

199 Origin, Discussion Paper submission, p. 2.

200 GDFSAE, Discussion Paper submission, pp. 8-9.

201 QGC, Discussion Paper submission, p. 6.

202 Industry statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

203 APGA, Discussion Paper Submission, p. 32.

204 APA, Discussion Paper submission, p. 9.

The Australian Petroleum, Production and Exploration Association (APPEA) argues that the differences between each of the facilitated markets require participants who operate in each of the market to have different information technology, administrative and compliance systems in place. APPEA notes that these add costs and can be a barrier to entry. APPEA recommends the AEMC investigate ways to more closely align these markets to improve their efficiency and effectiveness, and produce market arrangements that are more closely aligned with the AEMC's objective of ensuring gas flows to its highest value use.[205]

Consistency between market parameters

APGA considers that aligning the market parameters, such as gas day timing and market price caps, across the facilitated markets will improve efficiencies, reduce complexity and increase opportunities for trade across the market.[206]

Alinta suggests that issues currently worthy of consideration are greater alignment of market parameters, in particular the significant differences in market price caps, establishing a common gas day to enhance coordination of trading and aligning prudential requirements across the gas and potentially electricity markets.[207]

QGC points out that harmonising the gas day across states and consistency of trading periods and settlement processes would make it easier to trade gas across the east coast.[208]

Origin sees limited benefit in a work program to harmonise the gas markets under one single design, with the costs likely to outweigh any benefits. Although, harmonising parameters, such as gas day start times, prudential requirements and market price cap and cumulative price threshold should be explored. Origin also suggests there may be merit in the way AEMO presents data for each market to promote consistency and reduce complexity and cost, for instance:

- Definition of terms in each facilitated market.
- Consistency in reports provided by AEMO.
- Timeliness of data provided by AEMO.
- Standardised gas market format for how data is provided and received.

The ESAA argues that to improve trading and liquidity, reducing transaction costs and minimising pricing risks is essential. The ESAA also suggests that investigating options to harmonise the STTM and DWGM would be a positive initiative and this could include the creation of a single gas day (noting there are currently three), consolidation of prudential requirements and harmonisation of market parameters.[209]

205 APPEA, Discussion Paper submission, p. 3.

206 APGA, Discussion Paper submission, p. 13.

207 Alinta Energy, Discussion Paper submission, p. 5.

208 QGC, Discussion Paper submission, p. 6.

209 ESAA, Discussion Paper submission, p. 4.

Lumo Energy argues that while the STTM hubs clearly add value through flexibility in managing gas portfolios, they can be improved by harmonising the start of the gas day across the STTM and DWGM, which Lumo consider would reduce barriers to entry.[210]

Future development of the facilitated markets

AGL suggests a review aimed at simplifying the rules and services provided by AEMO for the STTM hubs and note this could take the form of dispensing with the pricing functionality in the STTM hubs, while maintaining incentives for balancing. AGL notes there may be other ways to reduce complexity and help lower the significant costs of participating in and administering the STTM.[211]

EnergyAustralia argues that the current market arrangements are not appropriate to meet the challenges of the future. Specifically, there are three fundamentally different types of facilitated markets for trading gas that are complex and were designed independently of the others. EnergyAustralia point out that deviations and imbalances are managed in a different manner across the STTM and DWGM, which increases complexity and costs. As such, market development needs to focus on improvements targeted to individual markets, but guided by a coherent strategy.[212]

Adelaide Brighton notes that the STTM and Wallumbilla GSH provide large industrial consumers greater access to wholesale markets in addition to the standard gas contract model. These markets provide industrial customers with price transparency and liquidity that can assist in reducing the average price of gas.[213]

However, Adelaide Brighton considers that, given the three different facilitated market designs, there would be efficiency gains from a uniform regulatory framework. They note that the DWGM could function as an STTM hub, allowing for gas purchases and sales within Victoria to be consistent with STTM in Adelaide and Sydney.[214] A key improvement to the STTM would be to allow the full settlement of market schedule variations through the STTM settlement system.

Qenos supports the full settlement of MSV's through the STTM settlement system to negate the need for individual parties to put in place separate documentation with other market participants for MSV transactions. Qenos would prefer this to the introduction of intra-day trading, which is likely to increase the level of resources required to participate in the STTM.[215]

Santos argue that the complexity of multiple different market rules, mechanisms, timings and administration requirements mean that new entrants require significant time to gather the expertise to effective manage the risk of using multiple markets.

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210 Lumo Energy, Discussion Paper Submission, pp. 6-7..

211 AGL, Discussion Paper submission, p. 2.

212 EnergyAustralia, Discussion Paper submission, p. 3.

213 Adelaide Brighton Cement Limited, Discussion Paper submission, p. 2.

214 Adelaide Brighton Cement Limited, Discussion Paper submission, p. 2.

215 Qenos, Discussion Paper submission, p. 2.

Santos recommends the AEMC consider standardising all balancing markets so there is one model across all regions to reduce complexity for participants.[216]

Alinta Energy supports the AEMC investigating benefits potentially associated with consolidating the facilitated markets into a single Australian gas market, while acknowledging the extent of this task.[217]

Stanwell sets out a long term vision for the gas market based on the design of the NEM where AEMO would play a prominent role in scheduling flows and determining prices based on injection and withdrawal bids. Under this model, all pipeline investment would be regulated by the AER and buyers would pay usage charges based on consumption. A balancing market would be operated by AEMO, with the cost of operating the service recovered from consumers.[218]

APA considers the STTM design could be simplified to become solely a gas balancing market. This could take the form of AEMO preparing monthly MOS allocations through a competitive tender process, with deviations allocated by the pipeline operator to shippers on a daily basis. APA considers this design would reduce costs and remove market risk created by setting an ex ante price, while resolving the issues counteracting MOS issues. It would also concentrate liquidity at supply hubs, which have greater potential to develop into liquid and deep trading locations.

APA argues that this change to the scope of the STTM could be applied to Brisbane in the first instance due to its close proximity to Wallumbilla.[219] While noting that the current market structure is meeting the needs of participants, APA has put forward a future vision that includes establishing gas supply hubs at natural trading points, such as Moomba and in Victoria, and simplified market-based balancing at demand centres.

With respect to the Brisbane STTM, Origin argues that the success of the Wallumbilla GSH "suggest there is a strong impetus to cease operations of the Brisbane STTM." Origin considers the balancing function performed by this market could be undertaken at Wallumbilla and has undertaken preliminary work around how this could occur.[220]

In discussing the impact of counteracting MOS in the STTM, and in particular in Adelaide, the AER notes that actions of those outside the hub, such as gas-fired generators, can potentially lead to counteracting MOS. The AER considers it worth exploring whether the current geographical limitations of the Adelaide STTM hub are appropriate, including whether gas-fired generation should be excluded.[221]

Lumo Energy argues that while the STTM hubs clearly add value through flexibility in managing gas portfolios, they can be improved through reviewing the MOS arrangements in the STTM.[222]

216 Santos, Discussion Paper submission, p. 3.

217 Alinta Energy, Discussion Paper submission, p. 5.

218 Stanwell, Discussion Paper submission, p. 1-2.

219 APA, Discussion Paper submission, p. 10.

220 Origin, Discussion Paper submission, p. 4

221 AER, Discussion Paper submission, p. 3.

222 Lumo Energy, Discussion Paper submission, p. 3.

Value of STTM ex ante price signals

APGA notes that the STTM is not a true commodity supply price, rather it is the price of imbalance on the day and "it is the lack of demand for balancing services that drives a low price, not a surplus of commodity". APGA suggests that participants who do not use the service provided by the STTM are subsidising those that do.[223]

APA considers that the prices published in the STTM are not credible references, as the bulk of trades on the market are between related entities.[224]

Qenos has recently become a market participant in the Sydney STTM hub and sees the STTM as a potential alternative means of purchasing gas. Qenos notes that the STTM has facilitated communication, negotiation and increased commercial gas transacting between gas suppliers and customers. However, Qenos suggests that the STTM prices are not an accurate reflection of contracted gas prices because the STTM is primarily a balancing market.[225]

5.2.2 Inability to manage risk

Participants face price risk in the STTM through the ex ante commodity market and the on-the-day balancing market. These aspects are discussed below.

Ex ante price risk

With relatively stable gas supply and demand conditions in the east coast market historically, participants have generally traded gas on the STTM within the confines of their bilateral contracts, with the contracts acting as a natural hedge against price risk. For example, a large industrial user with a GSA will effectively be selling and buying the gas to itself at whatever the price is in the STTM and, thus, will be perfectly hedged from the ex ante price.

Price risks emerge when participants use the ex ante commodity market to sell or purchase gas outside of their contractual positions. For example, a retailer who has expected demand at a hub of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ and bid to withdrawal 100 TJ in the ex ante market. In this case, the retailer will be exposed to ex ante price risk on 20 TJ, which is the volume of gas not supplied under a long term contract.

As can be seen in Figure 5.4, the Adelaide STTM has experienced periods of high ex ante price volatility in between more moderate market outcomes.[226] Compared to one of the most liquid gas trading hubs internationally - the Henry Hub in North America - volatility is understandably higher in the Adelaide STTM due to the smaller number of participants and volumes of gas traded. Average volatility since market start across the STTM hubs has been highest in Brisbane, followed by Sydney, while Adelaide has exhibited the least ex ante price volatility on average.

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223 APGA, Discussion Paper submission, pp. 29-30.

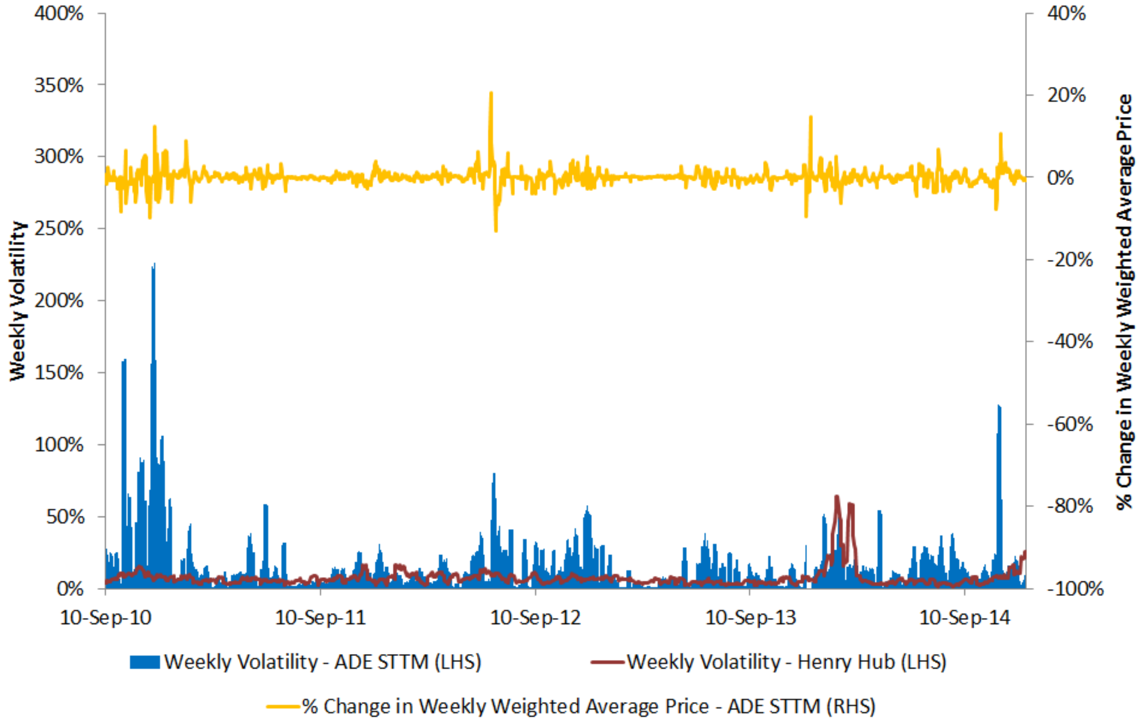
224 APA, Discussion Paper submission, p. 9.

225 Qenos, Discussion Paper submission, p. 4.

226 Adelaide was selected out of the three markets because it was found to be the least volatile of the hubs operating on the east coast.

Exchange-based financial derivative products are not currently available to hedge ex ante price risk in the STTM; although we understand some bilateral over-the-counter risk management products are being used.

Figure 5.4 Adelaide STTM ex ante price has exhibited periods of high volatility



Source: AEMC volatility analysis based on price and volume data sourced from AEMO (for the STTM) and price data sourced from the EIA (for the Henry Hub). STTM daily and weekly average prices were calculated by weighting ex ante prices by volumes. Weekly volatility was calculated using the methodology set out in: EIA, An Analysis of Price Volatility in Natural Gas Markets, August 2007.

Note: Volatility is driven by percent differences in prices of gas between days across a rolling week. Large price movements at higher prices may equate to a comparable level of volatility as a smaller price movement when natural gas prices are lower. Further, increasing natural gas prices do not necessarily indicate whether a market is volatile, since volatility is defined by the degree of price variation in the market, not by the level of prices or direction of price movements. See: EIA, An Analysis of Price Volatility in Natural Gas Markets, August 2007, p. 1.

On-the-day balancing price risk

The other form of price risk in the STTM is through the on-the-day balancing mechanism if a participant deviates from its ex ante schedules.

As the STTM has been designed to incorporate a balancing function, features of the market consistent with this service impose what have been described by participants as unhedgeable risks. These include variation payments and charges related to the use of market schedule variations, as well as deviation payments and charges, which are imposed when participants deviate from ex ante schedules and do not submit market schedule variations.

A detailed overview of the STTM's on-the-day balancing mechanism design, and the calculation of payments and charges, is set out in Appendix E.

Observations from previous reviews

As part of the Scoping Study, stakeholders raised the following concerns with the STTM relating to risk:[227]

- An inability to hedge against all of the risks associated with operating in this market because there is not a single daily price that reflects all of the costs payable by participants.
- The level of the MOS price cap, which some claimed was too high; the prevalence of counteracting MOS in the Adelaide market; the potential for the MOS arrangements to be gamed; and the inability of participants to offer MOS on a daily basis.
- The lack of visibility to participants around their exposure to deviation charges.

Deloitte noted as part of the ESAA's assessment of the east coast gas market that the STTM (and DWGM) has been a critical factor in enabling new entry by allowing participants without long term gas and transport agreements to gain initial access to retail markets before entering contracts. However, it was noted that GSAs and GTAs remain the primary approach to managing risk once participants have entered the market.[228]

However, participants interviewed by Deloitte suggested that the STTM has had little impact on transparency, as gas prices reflect only the long or short positions of participants and not the underlying GSA prices.[229]

Stakeholder submissions

Risk management and price transparency was a key theme reflected in submissions. Origin Energy highlights the following elements related to the STTM that may impede participants' ability to manage risk:[230]

- MOS service payments and commodity payments.
- Short and long deviations payments.
- Contingency gas.
- Settlement surplus and shortfall.

Origin "strongly supports improving the current arrangements so that each gas day is self-contained and participants are then able to manage risk on a single day without reference to other days." Origin notes that such an approach would require the MOS pricing arrangements to be re-evaluated so participants' face the full economic value of deviations, which could occur by implementing a marginal clearing price approach.[231]

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227 K Lowe Consulting, *Gas Market Scoping Study,* a report for the AEMC, July 2013, p. 96.

228 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, May 2013, p. 53.

229 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, May 2013, p. 60.

230 Origin Energy, Discussion Paper submission, pp. 2-3.

231 Origin Energy, Discussion Paper submission, p. 3.

The remaining submissions under risk management and price transparency are separated into the following categories:

- Intra-day trading.
- Value of STTM price signals.
- Development of financial derivatives.

Intra-day trading

Stanwell supports the introduction of intra-day trading to reduce imbalance charges, although they note that some users may not have access to their gas consumption data on an intra-day basis. Stanwell also argues that balancing services in the STTM may be more effective if shippers were able to offer MOS on a day-ahead basis, rather than a month-ahead. Alternatively, Stanwell raises the possibility that balancing is performed by the pipeline at a rate fixed by the AER.[232]

Lumo Energy argues that while the STTM clearly adds value through flexibility in managing gas portfolios, they can be improved through intra-day trading, which would provide market participants with the additional flexibility to manage portfolios over the course of a day. Lumo argues that the additional cost and complexity of intra-day trading would be outweighed by the benefits being able to better manage deviations.[233]

Development of financial derivatives

Plastics and Chemicals Industries Association (PACIA) supports the development of financial derivatives as another means for risk management, although notes that this will need a daily price to settle against. Simplifying the STTM registration process to encourage more participants and incorporating market schedule variation trading in the STTM is also supported.[234]

Qenos argues that while purchasing gas on the STTM can be cheaper than under bilateral contracts, the price risks are substantial for users who have limited demand response. This means that users such as Qenos still require long term gas supply contracts to manage this risk. In this context, Qenos would be interested in the AEMC exploring additional tools to manage STTM risk, such as financial derivatives that would enable short to medium term hedges.[235]

Santos notes that because trading in the facilitated markets is confined to "overs and unders" it is not always suitable for large industrial customers to manage their full commodity risk and for derivative contracts to be established. However, Santos argues the main impediment is the lack of firm transport capacity to get gas to and from the different trading markets.[236]

GDFSAE purports that within-day price signals, trading day definitions, consistency of trading periods and settlement processes should be set to facilitate trade and support a

232 Stanwell, Discussion Paper submission, p. 5.

233 Lumo Energy, Discussion Paper submission, pp. 6-7.

234 Plastic and Chemicals Industries Association, Discussion Paper submission, p. 7.

235 Qenos, Discussion Paper submission, p. 5.

236 Santos, Discussion Paper submission, p. 3.

more liquid market, including the development of forward products. Areas for investigation suggested by GDFSAE range from a rationalised market design, coordinated dispatch, use of understandable within day charges, better use of balancing and maximising trade, signalling the value of capacity and services inside hubs and consolidation of prudential regimes.[237]

5.2.3 Transaction costs associated with the value adding market functions

Costs incurred by AEMO in its role as operator of the STTM are recovered from participants by charging a fee for gas transacted through the hubs. Since participation in the markets is mandatory for parties wishing to ship gas to the hub and/or withdraw gas, this fee reflects an unavoidable transaction cost for these parties.

The STTM fee is currently $0.082/GJ and in 2014-15 AEMO has reported that it expects STTM expenditure to be $10.8 million. Around 40 per cent of AEMO's expenditure relates to labour costs, while 30 per cent is depreciation and amortisation.[238]

AEMO's fees for operating the STTM are higher on an inflation-adjusted basis than was expected when costs were estimated for the GMLG in 2006.[239] Consultants MMA estimated the ongoing costs for an Adelaide and Sydney STTM to be around $1.6 million annually, which equates to around $1.87 million in 2015.[240]

On this basis, STTM operating costs in 2014-15 are over five times those estimated by MMA in 2006, although AEMO's current fees include the operating costs for the Brisbane STTM, which was not included in the 2006 estimate.[241] However, we note that there appears to be large fixed costs associated with operating the STTM hubs. This is because AEMO's 2011-12 fees, which excluded the Brisbane STTM, were $10 million - marginally less than the 2013-14 fees of $10.1 million, which was the first full financial year the Brisbane STTM had been operating.[242]

Markets create value through bringing together buyers and sellers to trade amongst one another. As such, trades occurring between the same entities on the STTM should not be considered part of the "value" that the market creates. These transactions are occurring because of the compulsory nature of the STTM and would occur in their absence. In other words, the facilitated markets provide no additional benefit to market participants for within-participant trades.

Where the STTM creates value is by facilitating ex ante commodity trades and ex post deviation trades with other market participants. However, these types of trades account

237 GDFSAE, Discussion Paper submission, p. 10.

238 AEMO, *Consolidated Draft Budget and Fees: 2014-15*, Published May 2014, p. 15.

239 An average annual inflation rate of 2.5 per cent is assumed.

240 Gas Market Leaders Group 2006, *National Gas Market Development Plan,* Gas Market Leaders Group report to the Ministerial Council on Energy, Canberra, p. 38-39.

241 We note that if depreciation and amortisation is excluded from the 2014-15 fees, STTM operating costs are still around 50 per cent higher than expected when the market was designed.

242 AEMO, *STTM final budget and fees 2013-14*, p. 8. Note that the $10.6 million "total STTM costs" for 2013-14 shown in Table 5.1 below is the sum of 'AEMO expenditure' ($10.1 million) and "MOS allocation service costs" ($0.5 million).

for only 3 to 13 per cent of total volumes across the STTM hubs, as shown in orange in Figure 5.2 above.

If the annual cost of operating the STTM is only recovered from gas that is traded for the purposes of settling ex ante commodity trades and ex-post deviation trades, the per GJ AEMO fee rises from approximately $0.08/GJ to approximately $0.89/GJ across the STTM hubs.[243] This indicative cost is relatively high in the context of gas prices typically observed in the STTM hubs of $3.8-4.3/GJ (20-23 per cent).[244] It also does not include the costs associated with the time and resources individual firms must dedicate to operating in the STTM.

The current structure for recovering AEMO's costs of operating the STTM has, arguably, resulted in those trading mostly in balance (where injections equal withdrawals) being charged a disproportionate amount, relative to those who rely more on the ex ante commodity and balancing functions. This is evident in the difference between AEMO's market fee and the indicative market fee that would be levied if the costs of the market were only recovered from the trades facilitated by the STTM, as can be seen in Table 5.1.

Table 5.1 AEMO $/GJ STTM fees would be significantly higher if levied only on ex ante commodity and ex post deviation trades

	2011-12	2012-13	2013-14
Total STTM costs ($m)	11.3	10.7	10.6
Total withdrawals (PJ)	139	164	166
Ex ante commodity and ex post deviation trades (PJ)	11	10.5	11.9
Actual AEMO fee ($/GJ)	0.07	0.07	0.08
Implied AEMO fee ($/GJ) – based on ex ante commodity and ex post deviation trades	1.03	1.02	0.89

Source: AEMC analysis using AEMO supplied expenditure and gas trade data.

Note: "Total STTM costs" include both AEMO expenditure and MOS allocation service costs.

Observations from previous reviews

As part of the ESAA's assessment of the east coast gas market, Deloitte estimated that transaction costs in the STTM were approximately $1 per GJ traded. The review suggested that these high costs appear to be driven by the low volume of gas traded

243 These cost increases have been calculated by the AEMC using AEMO supplied expenditure and gas trade data between 2010-11 and 2013-14.

244 Average STTM prices are based on volume weighted quarterly prices published by the AER.

between participants. Deloitte also noted that the significant differences between the STTM and DWGM designs can increase costs for participants operating across jurisdictions.[245]

Stakeholders in the Scoping Study expressed mixed views on the STTM, with some participants noting that it provides a useful way to manage imbalances and has enhanced price transparency, while others noted that little trade was actually undertaken through the STTM and that prices were not particularly informative. Some stakeholders also noted there was little evidence to suggest new entrants could rely solely on the STTM to procure gas.[246]

The Eastern Australian Domestic Gas Market Study noted that the STTM was designed to complement long term gas contracts and provide an option for making up short run supply and demand shortfalls. The report identified that the STTMs currently trade insignificant gas volumes and may have only a limited relevance to the price of the long-term gas contracts.[247]

Stakeholder submissions

Most submissions to the Discussion Paper comment on the high transactions costs associated with the STTM, with general consensus that this was an issue the AEMC should explore further in the review. For instance, the ESAA notes that, while the STTM hubs are generally considered beneficial, they come at a relatively high cost, which is estimated at around $1/GJ.[248]

Similarly, Stanwell argues that the STTM hubs impose significant costs on participants, pointing out that nearly half of AEMO's annual budget for operating the STTM, or $4.9 million, is labour costs, which "seems to be very high given market operations should be highly automated".[249] Stanwell is also of the view that there is no evidence participants are relying on the STTM solely for their gas supply - rather it is primarily used for managing "unders and overs."[250]

AGL notes that the facilitated markets are essentially balancing arrangements in downstream distribution networks and suggests that "the markets are characterised by complexity and resultant overhead costs which culminate in a service cost per GJ, particularly in the STTM, which overwhelm any value to be had from trading in the market".[251]

245 ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform,* May 2013, p. 62-63.

246 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, p. 96.

247 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 64.

248 ESAA, Discussion Paper submission, p. 4.

249 Stanwell, Discussion Paper submission, p. 4.

250 Stanwell, Discussion Paper submission, p. 4.

251 AGL, Discussion Paper submission, p. 1.

Arrow Energy notes that although it does not participate in the STTM (and nor does it have any intention to enter this market in the future), it has been made aware of the significant costs and administration burden attached to the STTM.[252]

5.3 AEMC's Stage 1 findings

This section details our assessment of the STTM and future opportunities for the development of the market. These opportunities primarily stem from the increasing maturity of the east coast gas market, together with the changing dynamic driven by LNG exports, and draw on issues raised in submissions and observations from earlier reviews. The future development opportunities will form the basis of the analysis undertaken as part of Stage 2 of this review.

We also outline Stage 1 recommendations consistent with the terms of reference, which represent 'no regrets' changes where implementation can begin immediately, irrespective of the future development of the STTM and its role in the broader east coast gas market framework.

5.3.1 Future opportunities to develop the market

The STTM was conceived at a time when the east coast gas market looked very different to what it does today. In 2006, the only wholesale spot market for gas was the DWGM and governments identified the need to increase market transparency and provide participants with additional options for pricing imbalances and trading incremental gas outside of bilateral contracts.

The market was originally designed to meet three broad objectives set out by the GMLG, namely:

1. Establish a mandatory price based balancing mechanism for gas delivered and withdrawn from defined market hubs, replacing existing gas balancing arrangements at delivery points within hubs.
2. Facilitate gas trading on a daily basis at market driven short-term prices.
3. Provide pricing signals and facilitate secondary trading between shippers and users, for gas-fired generators, for trading over interconnecting pipelines between hubs, and to facilitate greater demand side response.

The STTM is generally regarded by participants as providing an effective and competitive gas balancing service and facilitating trade at demand centres based on short-term prices, albeit at a high transaction cost. However, there is little evidence that the market has facilitated pipeline capacity trading or demand side response. This may, in part be due to the location of the hubs at the end of long transmission pipelines, which limits the ability to move gas to different demand centres, and the use of bilateral contracts to manage risk.

The mandatory nature of the STTM results in only a small portion of total gas "traded" on the market actually benefiting from the market arrangements directly. This was commonly referred to by stakeholders as part of this review, as well as in the

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252 Arrow Energy, Discussion Paper submission, p. 8.

observations from previous reviews. The complexities associated with the current market design may impose disproportionate administrative costs on the market, particularly when considering the small proportion of trades the STTM facilitates. Participants who trade within their bilateral contracts incur a fee for participating in the market, irrespective of whether they have derived any value from the arrangements.

The STTM also represents an added level of complexity for entities wishing to operate across jurisdictions as it is characterised by a different set of arrangements to the DWGM in Victoria, although the practical roles of each market are similar. Submissions to this review and the observations from previous reviews have largely reiterated the sentiment that the STTM is a complex and costly market, relative to the value it adds.

The emergence of the gas supply hub, in conjunction with the above analysis and feedback from stakeholders, suggests that the primary use of the STTM is for balancing and that the markets are unlikely to develop into commodity trading hubs. This indicates it is an opportune time for reflection on the role of the STTM in the broader east coast gas market, as well as the facilitated markets more generally. In particular, the AEMC considers there is merit in considering whether:

1. the originally stated STTM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
2. if not, whether the objectives and design of the STTM needs to be re-focussed, taking into account developments in the broader east coast market and the STTM's role alongside other facilitated markets.

We anticipate this will involve consultation with stakeholders around the type and number of facilitated markets on the east coast and how best to develop the markets such that they meet their objectives and the needs of participants efficiently.

This will likely include investigating the scope for increasing the consistency in gas market designs across the east coast to minimise complexity and transaction costs, where practicable.

This analysis will be progressed during Stage 2 of the project. We do however see scope for a focussed, technical working group to begin assessing how the STTM design could transition to a simple balancing market as outlined below.

5.3.2 Stage 1 recommendations

As part of Stage 1 of the East Coast Review and the Victorian Review, we consider it prudent to give consideration to whether there are any existing issues that can be resolved with the intention of enhancing the ability of the STTM to achieve the NGO, irrespective of what future shape the facilitated market arrangements may take (the outcome of Stage 2).

Stakeholder submissions support the view that the STTM is overly complicated for the purpose it is currently serving and may be imposing unnecessary transaction costs on market participants. It would appear inevitable that the design of the STTM will need to evolve to meet the Energy Council’s Vision of liquid, wholesale markets. We are therefore suggesting the formation of a technical working group led by the AEMC and including AEMO, market participants and others as appropriate that will be tasked with scoping how to transition the STTM from its current design to a simple balancing market. The group will provide their assessment back to the AEMC to be considered as part of our Stage 2 recommendations on the broader market design framework.

Based on submissions to the Discussion Paper, we consider harmonising gas day start times on the east coast is likely to reduce transaction costs and therefore might promote the NGO.

Gas days currently start at differing times across the east coast, for instance:[253]

- 6.00am for the DWGM in Victoria.
- 6.30am for the Sydney and Adelaide STTM hubs.
- 8.00am for the Brisbane STTM hub and Wallumbilla supply hub.

A large number of submissions to this review called for the harmonising of gas day start times, prudential requirements and risk parameters, such as market price caps and cumulative price thresholds across the east coast facilitated markets.[254] The inconsistency between these aspects of the markets was also raised by stakeholders as in the Scoping Study.[255]

Having a consistent gas day start is likely to remove some of the complexity for parties that operate across multiple markets and assist the process of increasing the interoperability across all the facilitated markets.

Given the widespread support shown for such a change to-date through submissions to the Discussion Paper, the final Stage 1 recommendations of this review could include a rule change that the Energy Council could submit to align gas day start times.

We would be interested in the views of stakeholders regarding the practicalities of implementing such a change, in particular whether gas day start times should be harmonised across gas markets alone (and, if so, what time should be selected and why), or whether this harmonisation should also include the electricity market (ie aligning the gas day start times with the 4.00am day start time in the NEM).

We are also interested to hear views on any costs that may accompany this change, for example the amendment of existing bilateral contracts and the recalibration of metering systems.

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253 The gas day start times are prescribed in the NGR for both the STTM and the DWGM. The gas day start time for products offered on the Wallumbilla GSH are specified in the exchange agreement developed by AEMO.

254 See for example submissions received from Origin, Santos, QGC, APGA, Alinta, GDF, Arrow Energy, ESAA and the industry statement (supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association).

255 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 97.

We note that most submissions to this review (as well as previous reviews) that called for harmonising of gas day start times across the east coast also called for consistency in a number of other market parameters, such as market price caps, trading periods, settlement periods and consolidating prudential requirements.

We are of the view that these market parameters are more fundamentally linked to the overall market design. Our preliminary view is therefore that these additional market parameters/design aspects should be considered as part of a more thorough consideration of the role and design of the facilitated markets on the east coast (undertaken in Stage 2 of this review). We would appreciate the views of stakeholders on whether any harmonisation across the facilitated markets beyond the gas day should be progressed in Stage 1 of this review.

6 Declared Wholesale Gas Market

Box 6.1 Summary of findings and recommendations

When the DWGM was developed, there were no STTM hubs, no gas supply hubs and no large-scale LNG development in Queensland. The Victorian system operated in isolation from the rest of the east coast pipeline transmission system because it was not physically connected.

Today, the DWGM is generally regarded as providing an effective and competitive gas balancing service that facilitates the trading of gas in Victoria. Victoria has relatively high levels of retail competition in gas compared to other jurisdictions, in-part due to the presence of the DWGM.[256] Nonetheless, and as with the STTM hubs, only a small portion of total gas 'traded' arguably benefits from the centralised market arrangements.

Complexities associated with the DWGM design may impose disproportionate operational and administrative costs on participants. Additionally, the material differences between the DWGM and STTM represent an added level of complexity for firms wishing to operate across jurisdictions, even though the practical roles of these markets are similar.

Similar to the STTM, the AEMC considers it an opportune time to consider if:

- the originally stated DWGM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
- if not, whether the objectives and design of the DWGM need to be re-focussed, taking into account developments in the broader east coast market and the DWGM role alongside other facilitated markets.

The AEMC will progress this issue as part of Stage 2. However, taking into account stakeholders' views in submissions and analysis in this chapter, we outline our preliminary views on two Stage 1 recommendations, which represent 'no regrets' changes where implementation can begin immediately.

First, removing the current NGL limitation on who can submit DWGM rule changes is likely to reduce the costs to concerned parties of engaging with AEMO, which may be currently acting as a barrier to smaller participants and potential new entrants to influence market development. Removing this will likely introduce a dynamism to the DWGM that will promote the NGO.

Second, as noted in Chapter 5, the final Stage 1 recommendations may include a rule change that the Energy Council could submit to align gas day start times.

256 AEMC, 2014 Retail Competition Review, Final Report, 22 August 2014, p. 183.

6.1 Market overview

This section provides an overview and background to aspects of the DWGM relevant to the issues considered throughout this review. It covers the original objectives for establishing the DWGM, key design features as well as how the market operates in practice. We have also included a detailed appendix on how the DWGM operates in practice (see Appendix F).

Market objectives

The DWGM was established by the Victorian Government in March 1999 and the objectives for doing so were as follows:[257]

- To support full retail competition – The market carriage model and the DWGM were seen as a way of encouraging new entry by retailers because they would not need to enter into long-term GTAs and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.
- To encourage diversity of supply and upstream competition – The transparency of pricing provided by the DWGM and the operation of the market carriage model were expected to encourage the development of new sources of supply and upstream competition.

In addition, the DWGM and market carriage arrangements in Victoria were developed to reflect the physical characteristics of the DTS. In particular:

- the DTS was essentially not connected to the rest of the east coast at that stage (eg the Eastern Gas Pipeline, the SEA Gas Pipeline and the Tasmanian Gas Pipeline had not been built) with supply effectively coming from one supply source (ie Longford);
- the DTS was, and still is, a physically highly meshed network that, at the time, had a large amount of spare capacity;
- the amount of gas that can be stored in the DTS was relatively small and cannot be relied upon to manage significant deviations between demand and contracted supply (LNG storage plays an important role in managing peak day demand);[258] and
- the demand profile was, and still is, largely characterised as exhibiting a significant degree of seasonal and daily variability (as a result of high residential heating load).

257 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11; and VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, pp. 21-24.

258 A 2002 report by VENCorp states that total linepack in the DTS varies between about 450 TJ and 600 TJ over each day as the system demand is satisfied and that on peak days over 1,100 TJ is shipped through the network, or approximately twice the entire linepack in the system. By way of comparison, the then peak demand on the Moomba to Sydney pipeline was stated to be approximately 25 per cent of the daily transported volume. See: VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 23.

These physical characteristics mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained. The physical characteristics also meant that it was considered to be very difficult to determine how to define firm capacity rights to shippers (ie, as opposed to the rest of the east coast that operate more on a 'point-to-point' basis).[259]

Market design

In February 2007, the DWGM moved from the original market design based on daily ex-post price determination to one where prices were determined on an ex ante intra-day basis. This shift was the result of a review conducted by VENCorp during 2003-04 that found the then existing ex-post design did not provide participants with either the ability or the incentive (ie, the price signal) to respond to changing market conditions during the day.[260] In particular, at the time it was thought that ex-post price signals would not serve the needs of gas-powered electricity generators (expected at the time to have an increasing presence in the generation sector going forward) and these participants needed the ability to re-nominate their bids and offers.

Market operation

It is generally the view of market participants that the DWGM has been working well since market-start, encouraging retail competition in Victoria and providing market participants with an effective mechanism to trade imbalances. Evidencing this is the range of physical gas market participants, such as retailers, gas-fired generators and large industrial customers, that now use the DWGM (the number and type of participants currently registered at each hub is set out in Table F.2). In addition, a number of participants appear to use the DWGM as means of initially entering the gas market, before committing to a bilateral gas supply and gas transportation agreement.

Similar to the STTM hubs, the majority of gas transacted through the DWGM is by participants who are selling gas into the market and at the same time buying it back. This is because, while the DWGM is compulsory, most participants have underlying gas supply agreements in place and do not need to use the DWGM to trade with different entities.

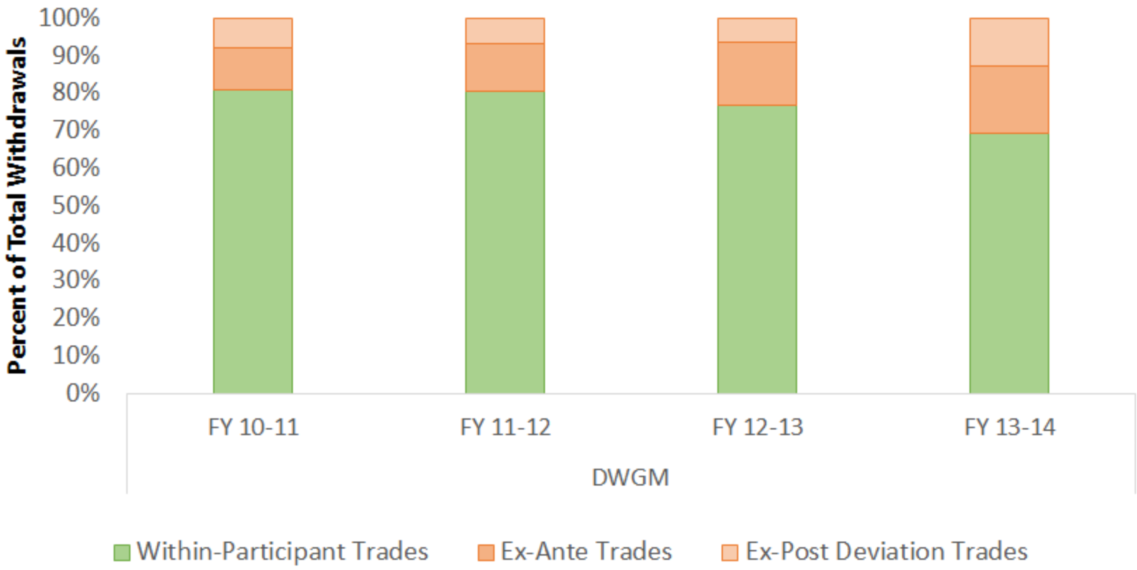
Figure 6.1 categorises DWGM transactions between 2010-11 and 2013-14 into three types: within-participant trades, ex ante trades and ex post deviation trades. The figure shows that approximately 80 per cent of total transactions in the DWGM are within-participant trades.[261] It shows that the majority of gas transacted through the DWGM has been between the same entities, with a small proportion traded through ex ante and as ex-post deviation trades.

259 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11.

260 VENCorp, *Victorian Gas Market Pricing and Balancing Review,* Recommendations to Government, 30 June 2004.

261 The actual percentages are 81 per cent for 2010-11 and 2011-12, 77 per cent for 2012-13 and 69 per cent for 2013-14.

Figure 6.1 Majority of trades on the DWGM are within-participant



Source: AEMO. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities before each schedule; ex post deviation trades is deviations during schedules.

As the majority of trades that occur on the DWGM are within-participant, the level of trading liquidity between different entities is generally low.[262] Consequently, the ex ante price is unlikely to be a robust reference price that market participants can trade around and, as discussed in section 6.2.2, is generally considered to reflect imbalances between daily gas requirements and long-term contract positions.

6.2 Key issues in the DWGM

A number of reviews have been carried out over the last 24 months identifying potential issues with the DWGM design. These include:

- ESAA's assessment of the east coast gas market, which was prepared by Deloitte in May 2013;[263]
- AEMC's Scoping Study that was published in July 2013;[264]
- Victorian Gas Market Taskforce that was competed in October 2013;[265] and
- Commonwealth Department of Industry and BREE's Eastern Australian Domestic Gas Market Study, which was published in January 2014.[266]

Section 295(3) of the NGL currently provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[267]

262 Liquidity in this context is defined in chapter 5.1 as the ability to buy or sell gas without causing a major change in price and without incurring significant transaction costs.

263 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013.

264 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013.

265 Victorian Government, *Gas Market Taskforce*, Supplementary Report, October 2013.

266 Department of Industry (Australian Government) *Eastern Australian Domestic Gas Market Study*, January 2014.

Since commencement of the DWGM in 1999, AEMO has submitted six rule changes to the AEMC for consideration since it took over responsibility for rule changes from VENCorp in 2009. These are summarised in Table F.2.

Matters considered in this chapter

The following sections of this chapter set out the key issues that have been identified in the DWGM, drawing on observations from previous reviews, submissions to this process and analysis by the AEMC. The issues are presented in three categories:

- DWGM complexity and the value of the ex ante price signal (considered in section 6.2.1).
- Inability to manage risk (considered in section 6.2.2).
- Transaction costs associated with value adding market functions (considered in section 6.2.3).

These three issues are synonymous with those identified in chapter 5 for the STTM. This is a result of the two markets providing the same fundamental services (a balancing trading service and a spot commodity trading service),[268] even though the two detailed market designs differ markedly. The analysis in this section is therefore similar to that in chapter 5 for the STTM hubs but presented again to maintain autonomous chapters.

6.2.1 DWGM complexity and the value of the ex ante price signal

This section outlines how operating in the DWGM is complex relative to its primary function, which is to facilitate the trade of short-term imbalances. This complexity extends to parties operating across the STTM and DWGM.

In this section we also cover price transparency in the DWGM, including the value of the ex ante price signal to market participants, how it is set and what prices represent in terms of supply and demand.

Complexities associated with the DWGM

As outlined above, the DWGM is a complex market designed to offer a balancing trading service, a spot commodity trading service and to allocate capacity on the DTS. The complexities associated with a market designed to provide all of these functions may be one of the reasons behind the high per GJ transaction costs associated with operating in and administering the market, relative to the volume of trades that benefit directly from the imposition of the market (as outlined in section 6.2.3).

Complex energy market designs may, depending on the objectives of the market, be unavoidable. Electricity and natural gas are commodities that both exhibit unique physical characteristics that influence the means of exchange. However, the level of complexity and resultant costs should be minimised, while the value a centralised market provides to its participants should be greater than its costs.

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267 Victoria is currently the only adoptive jurisdiction.

268 In contrast to the STTM, the DWGM is also used to allocate the capacity of the DTS amongst market participants via the scheduling process. The allocation of pipeline capacity is done outside of the market in the STTM (via bilateral contracts).

Some of the complexities inherent in the design of the DWGM are manifested in the number of potential price risks that participants could be exposed to. These include:

- the ex ante price;
- three types of complex uplift charges participants may face (congestion uplift, surprise uplift and common uplift);[269] and
- deviation payments.

While the ex ante price is determined before each schedule, the other price risks are generally a function of what occurs during the gas day. A detailed overview of these design aspects is set out in Appendix F, with further analysis of risk management in the DWGM outlined below in section 6.2.2.

In addition to being complex relative to the primary role the DWGM currently plays in the east coast gas market, differences between the DWGM and STTM may be acting as a barrier for firms looking to enter both markets; or contributing to additional costs for participants who currently operate in both of these markets. As the DWGM and STTM are both used primarily for balancing and incremental ex ante commodity trades, there is likely to be value in considering measures to harmonise aspects of the market designs.

Some of the key differences between the STTM and DWGM include:

- market terminology;
- start time for gas trading days (6.00am in the DWGM, 6.30am in the Sydney and Adelaide STTM hubs and 8.00am in the Brisbane STTM hub);
- trading periods (DWGM has 5 intra-day trading periods, while the STTM operates on a day-ahead basis);
- market price caps ($800/GJ in the DWGM and $400/GJ in the STTM hubs); and
- separate prudential requirements.

In the Scoping Study, stakeholders noted that the resources required to become acquainted with operating in Victoria may be deterring producers and large users from participating or deterring those shippers that just want to export gas from Victoria.[270]

Value of the DWGM ex ante price signal

As discussed above, the current DWGM market design requires that all gas withdrawn from the DTS to be transacted through the market. Since the majority of transactions that occur on the DWGM are within-participant trades, the level of liquidity underpinning the market price in the DWGM can be considered low. An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times.

Figure 6.2 presents a stylised example of the supply and demand conditions inherent in the ex ante DWGM price signal and how they contribute to an overall low level of illiquidity in the market. Each coloured segment of the curves represents a particular

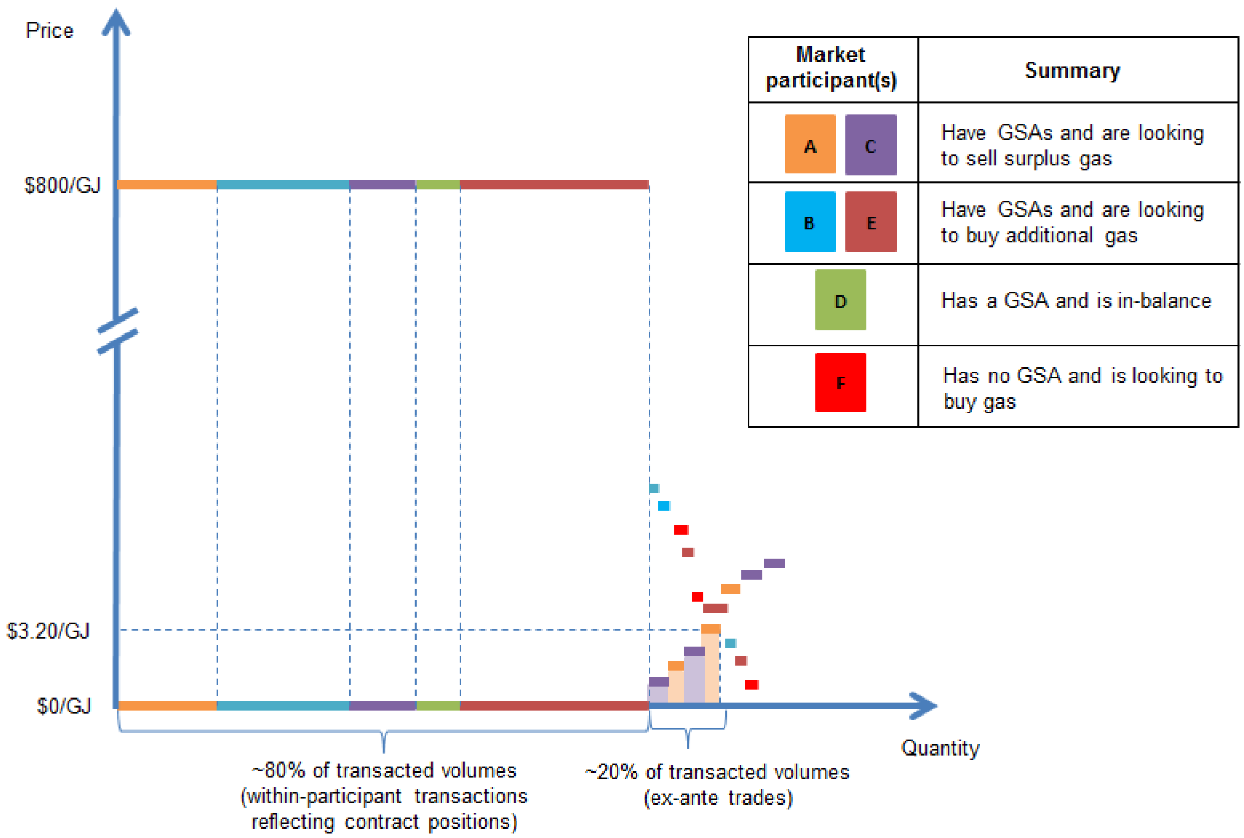
269 Uplift charges are further discussed in Appendix F.

270 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 91.

bid or offer price and volume pair by a market participant (there are six assumed market participants, each represented by a different colour). Price is represented on the vertical axis, while volume is represented on the horizontal axis (the length of each coloured segment denotes how much volume a participant is willing to buy or sell to the market at that price). The overall positions of each market participant are summarised in the box next to the figure.

The quantities of gas that participants require to meet contractual obligations (the flat sections of the supply and demand curves) can be thought of as representing absolute illiquidity since market participants require these volumes of gas to fulfil their contract obligations (these volumes are highly price inelastic). As such, we would expect market participants to submit bids and offers for these volumes that ensure they are scheduled (these bids and offers are assumed to be \$800/GJ (the market price cap) and \$0/GJ, respectively, in the example below). The remaining bids and offers are essentially those that set the market price in the DWGM.

Figure 6.2 Stylised example of the supply and demand conditions inherent in the ex ante DWGM price signal



Source: AEMC analysis.

Since most participants endeavour to align their bids and offers so as to not be exposed to the DWGM ex ante price risk (as the green participant 'D' in Figure 6.2 has done), the remaining bids and offers reflect daily imbalances between participants’ requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to approximately 20 per cent of total volumes.[271]

Consequently, the observed DWGM ex ante market price is susceptible to both a small volume of trades and a small number of market participants.

Observations from previous reviews

Concerns were raised by a number of stakeholders in the Scoping Study about the complexities and costs associated with operating in the DWGM and the potential for these to act as a barrier to entry into the market. Stakeholders suggested the following improvements to the DWGM as part of this study:[272]

- Simplifying unnecessarily complex elements of the DWGM.
- Harmonising certain elements of the DWGM (such as the start of gas day and market price caps) across all facilitated markets to reduce the risk of arbitrage across the markets and the costs faced by participants operating in these markets.
- Pool prudential requirements across the DWGM and STTM and allow subsidiaries to pool prudential requirements.

The Scoping Study also found that the complexities associated with operating in the DWGM (and the market carriage arrangements applying to the DTS) represents an additional complexity for those shippers that just want to export gas from Victoria.[273]

There was a general perception across all stakeholders consulted with as part of ESAA's assessment of the east coast gas market that the facilitated markets (and associated interventions such as the Gas Bulletin Board and GSOO) impose significant costs on participants. Shippers noted that key costs for trading participants include registration and activity fees, and the need for enhanced IT systems and, in general, it was noted that the costs for interacting with the facilitated markets had grown over time.[274]

Stakeholder submissions

The complexity of the DWGM (and the STTM hubs) was raised in almost all submissions. In order to summarise stakeholders' views, we have separated the issues into four categories:

1. Complexity of the markets.
2. Consistency between market parameters.
3. Future development of the DWGM (and wider east coast).
4. The value of DWGM ex ante price signals.

271 As can be seen from Figure 6.1 this 20 per cent also includes ex-post deviations, which have been excluded from this stylised example for ease of exposition.

272 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, pp. 95-97.

273 K Lowe Consulting, *Gas Market Scoping Study,* a report for the AEMC, July 2013, p. 91.

274 ESAA *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 62.

Complexity of the markets

In its submission Origin Energy suggested a key principle to guide this review process should be to simplify the unnecessarily complex elements of the facilitated markets.[275]

MEU said that using the 'spot' function of the DWGM is very limited due to the complexity of market and the various adjustments made ex post (ie uplift charges).[276]

Santos noted that the complexity of multiple facilitated market rules, mechanisms, timings and administration requirements, mean that any new entrant would require significant time to gather the required expertise to effectively manage the risk of using a, or multiple, facilitated markets.[277]

APPEA notes that each of the three forms of facilitated market currently in operation on the east coast (ie the STTM hubs, the Wallumbilla GSH and the DWGM) is different and that these differences require participants who operate in each of these markets to have different information technology, administrative and compliance systems in place to participate in each of these markets. APPEA notes that these differences add costs for participants and can be a barrier to entry into these markets, particularly for smaller entities.[278]

AGL raised the issue of intra-day trading on the DWGM. AGL noted that, with the shift towards gas as a major generation fuel in Victoria not eventuating, the DWGM is characterised by a complex mechanism that is over-engineered for what it does. Noting this however, AGL stated that the absence of appreciable linepack and the peakiness of gas demand in Victoria sit well with the ability to revise bids and offers during the course of a gas day.[279]

Arrow Energy states that Australian gas markets are currently disparate, even though physically connected, creating inefficiencies or hurdles to transacting and that achieving supply across the complex arrangements is often not practical or adds significant cost and risk. Arrow Energy states that harmonising elements of existing markets (such as the start of gas day and market price caps) to reduce the risk of arbitrage across the markets, and the costs faced by participants operating in both markets, would reduce complexity and facilitate increased participation.[280] The views of other parties on the harmonising of these market parameters are outlined below.

275 Origin, Discussion Paper submission, p. 2.

276 Major Energy Users, Discussion Paper submission, p. 4.

277 Santos, Discussion Paper submission, pp. 6-7.

278 APPEA, Discussion Paper submission, p. 3.

279 AGL, Discussion Paper submission, p. 5.

280 Arrow Energy, Discussion Paper submission, p. 7.

Consistency between market parameters

Origin recommends aligning gas day start times, as well as potentially market price caps.[281] Santos also noted that aligning these two parameters had been raised in the earlier AEMC gas market scoping study and noted that it agrees that they should be aligned.[282]

QGC noted that there is a lack of harmonisation across the facilitated markets of key features including trading day definition, consistency of trading periods and settlement processes and, as a starting point, suggested that harmonising the gas day across the states (and potentially aligning to the timing of the electricity market) would make it easier to trade gas across the east coast.[283]

APGA noted an immediate action should be to align the market parameters across the facilitated markets.[284] Alinta also suggested harmonising market parameters and gas days.[285] GDFSAE expressed the view that market definitions, trading days, trading periods and settings and parameters should be rationalised.[286]

The GLECMU noted that within day price signals, trading day definitions, consistency of trading periods, and settlement processes should be set so as to facilitate trade and support a more liquid market including encouraging the development of forward products.[287]

ESAA considers that differences between the DWGM and STTM hubs can potentially increase costs for participants operating across these markets and that opportunities to deliver greater consistency between these markets is a positive initiative. The ESAA considers there is merit in examining:[288]

- a single gas day;
- consolidating prudential requirements (with consideration also given to the Wallumbilla gas supply hub and NEM); and
- harmonisation of gas market parameters.

The ESAA considers that the extent to which each of these increase costs for market participants is unclear and that any examination of these issues should therefore include a broad assessment of materiality as well as considering the extent to which any proposed change is appropriate in the context of each market.[289]

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281 Origin, Discussion Paper submission, p. 4.

282 Santos, Discussion Paper submission, p. 3

283 QGC, Discussion Paper submission, p. 6.

284 APGA, Discussion Paper submission, pp. 12 & 27.

285 Alinta, Discussion Paper submission, p. 5.

286 GDFSAE, Discussion Paper submission, p. 9.

287 Industry Statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

288 ESAA, Discussion Paper submission, p. 4.

289 ESAA, Discussion Paper submission, p. 4.

GDFSAE and Alinta both expressed a keenness to consolidate prudential arrangements across the facilitated markets.[290] Origin also recommended expanding prudential requirements from STTM and DWGM to the GSH and the NEM.[291]

Future development of the DWGM (and wider east coast)

Mixed views were raised in submissions as to the future of the DWGM as well as the wider east coast market. ABCL suggested that there are some efficiency gains to be extracted from a uniform regulatory framework on the east coast, allowing a common mechanism for the setting of spot prices. To this end, ABCL recommend that the DWGM be operated as a "Melbourne STTM hub" to ensure consistency with Sydney and Adelaide.[292]

Stanwell also supports the integration of the east coast gas markets, provided the benefits can be shown to outweigh the costs.[293]

Origin Energy, on the other hand, thinks there is limited value in a large scale overhaul of the gas markets to harmonise them under one single design (eg a STTM) and noted that such an exercise would be extremely costly and unlikely to deliver a commensurate level of benefit. Origin states that overseas examples such as Europe show that markets can be integrated effectively without requiring a single market model across those markets.[294] Similarly, AGL states its considered view is that the DWGM is generally best left alone as the costs of dismantling the existing arrangements and installing new rules and market systems are unlikely to result in net benefits.[295]

While noting that the current market structure is meeting the needs of participants, APA put forward a future vision that includes establishing gas supply hubs at natural trading points and simplified market-based balancing at demand centres. This could include transitioning the DWGM to a gas supply hub model supported by contract carriage pipelines and creating a separate balancing market for Victoria.[296] APA does not see this reform as urgent, more a vision for the long-term development of the market.

GDFSAE suggests adopting a coordinated dispatch across the east coast. GDFSAE provide the example of a market participant injecting at Moomba and state that they should be able to nominate Sydney and Adelaide and achieve the price that best matches the value of the commodity and transportation costs.[297]

GDFSAE also stated that signalling the value of capacity and services inside hubs does not presently occur and, ideally, the market would signal the value of solutions as they become known whether those solutions are pipeline, facility or storage orientated. GDFSAE goes on to state that the DWGM does not currently provide useful signals and

290 GDFSAE, Discussion Paper submission, p. 10; and Alinta, Discussion Paper submission, p. 5.

291 Origin, Discussion Paper submission, p. 4.

292 Adelaide Brighton Cement, Discussion Paper submission, p. 2.

293 Stanwell, Discussion Paper submission, p. 1.

294 Origin, Discussion Paper submission, p. 4.

295 AGL, Discussion Paper submission, p. 5.

296 APA, Discussion Paper submission, p. 29.

297 GDFSAE, Discussion Paper submission, p. 9.

encourages participants to push in significant amounts of gas to resolve a variety of issues and avoid charges.

GDFSAE proposes that the use of multiple nodes, with capacity signals between those nodes, may be worth considering and notes that the impact of having a series of nodes, in effect mini-hubs inside the Victorian network, should enable the market to signal for efficient responses. GDFSAE states that conceptually each hub on the east coast currently operates like a node; therefore the use of multiple nodes in Victoria is not an inconsistent approach to that applied currently.[298]

Value of DWGM ex ante price signals

APGA, APA and the MEU all noted that the observed prices in the DWGM do not represent a commodity price (or long-term value of gas) but rather an imbalance (or short-term constraint) price.[299] QGC stated that, due to the operation of specific design features and the size of the markets, it is questionable as to whether the published prices in the DWGM and STTM hubs always reflect the underlying supply and demand for gas, or whether they are impacted by other factors.[300]

GDFSAE noted the potential to develop a gross index of prices that reflects all trades within a hub, whether under bilateral contract or not.[301]

ERM Power is of the view that the market price cap in the DWGM is excessive and should be reviewed because it exposes retailers to undue risk. ERM Power has suggested that the price cap be lowered to around $100-200/GJ.[302]

6.2.2 Inability to manage risk

Participants face price risk in the DWGM through the ex ante commodity market and the uplift charging arrangements. The AEMC notes that market participants can face volume risk when transmission pipelines become constrained, although we understand this risk is low and, as the issue has not been raised to-date, is not discussed further.

DWGM market participants may also face volume risk associated with exporting gas from Victoria. While the AEMC considers there would be merit in investigating these issues further in the DWGM review, given the potential for these market design and interoperability factors to impede the efficient trade and movement of gas out of Victoria, our detailed consideration of these issues can be found in chapter 4.

Ex ante price risk

With relatively stable gas supply and demand conditions in the east coast market historically, participants have generally traded gas on the DWGM within the confines of their bilateral contracts, with the contracts acting as a natural hedge against price risk. For example, a large industrial user with a GSA will effectively be selling and buying

298 GDFSAE, Discussion Paper submission, p. 9.

299 APGA, Discussion Paper submission, p. 24; APA, Discussion Paper submission, p. 1; and Major Energy Users, Discussion Paper submission, p. 4.

300 QGC, Discussion Paper submission, p. 6.

301 GDFSAE, Discussion Paper submission, p. 10.

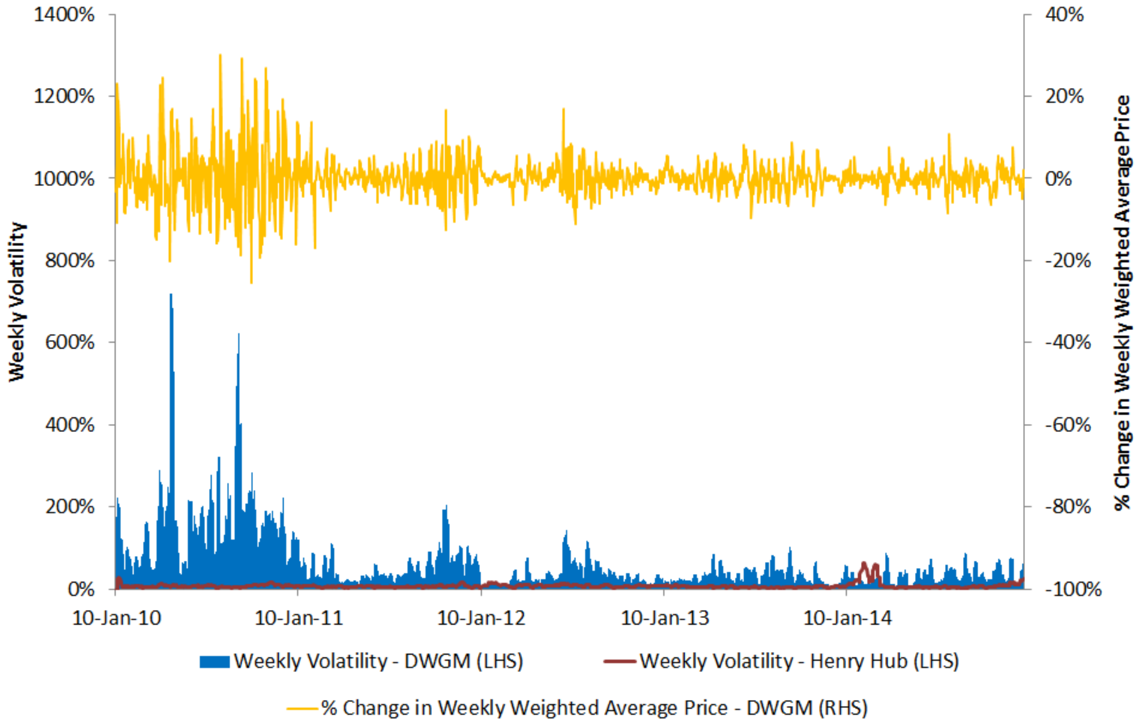
302 ERM Power, Discussion Paper submission, pp. 7-8.

the gas to itself at whatever the price is in the DWGM and, thus, will be perfectly hedged from the ex ante price.[303]

Price risks emerge when participants use the ex ante commodity market to sell or purchase gas outside of their contractual positions. For example, a retailer who has expected demand of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ and bid to withdrawal 100 TJ in the ex ante market. In this case, the retailer will be exposed to ex ante price risk on 20 TJ via an imbalance payment,[304] which is the volume of gas not supplied under a long-term contract.

As can be seen from Figure 6.3, the DWGM has experienced periods of very high ex ante price volatility historically and can be considered to be a highly volatile price generally. Compared to one of the most liquid gas trading hubs internationally - the Henry Hub in North America - volatility is understandably higher in the DWGM due to the smaller number of participants and volumes of gas traded.

Figure 6.3 DWGM spot price has been highly volatile historically



Source: AEMC volatility analysis based on price and volume data sourced from AEMO (for the DWGM) and price data sourced from EIA (for the Henry Hub). DWGM daily and weekly average prices were calculated by weighting schedule prices by traded volumes. Weekly volatility was calculated using the methodology set out in: EIA, An Analysis of Price Volatility in Natural Gas Markets, August 2007.

Note: Volatility is driven by per cent differences in prices of gas between days across a rolling week. Large absolute price movements at higher prices may equate to a comparable level of volatility as a smaller price movement when natural gas prices are lower. Further, increasing natural gas prices do not necessarily indicate whether a market is volatile, since volatility is defined by the degree of price variation in the market, not by the level of prices or direction of price movements. See: EIA, An Analysis of Price Volatility in Natural Gas Markets, August 2007, p. 1.

303 While we note market participants may be perfectly hedged from the ex ante price through their contract positions, they may still be exposed to uplift charges. The risk participants face from these charges is outlined in the section below. Uplift charges are outlined in detail in Appendix F.

304 The details of how imbalance payments work in the DWGM can be found in Appendix F.

As supply and demand conditions on the east coast become more dynamic, there are likely to be greater opportunities for participants to trade gas on a short-term basis, outside of their contract positions. To trade gas on a spot commodity basis, participants require a means to be able to manage their exposure to the price risk, something they cannot currently do for any gas traded outside of their contracts on the DWGM.

In 2009, the Australian Stock Exchange (ASX) introduced a number of derivative products that are linked to the price payable at the beginning of the day in the DWGM.[305] However, these products have not been heavily traded, which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers, and then selling it to themselves through the DWGM using bilateral contracts (and/or participants are choosing to just not use them). In addition, these ASX products only provide a hedge against the 6.00am ex ante price[306] (as determined with reference to the beginning of the day prices) and not against any uplift charges.[307]

Uplift charge risk

While market participants holding AMDQ or AMDQ cc[308] can use part or all of these limited rights as a partial hedge against congestion uplift charges, those that do not hold these instruments have no means to hedge against congestion uplift charges. In addition, market participants, whether they are holders of AMDQ or not, cannot hedge against surprise or common uplift charges.[309]

Observations from previous reviews

As part of the Victorian Gas Market Taskforce review, most stakeholders raised the need for greater transparency in forward gas prices in order to facilitate planning and risk management. In particular, some stakeholders were of the view that the DWGM spot price cannot be adequately hedged by futures products because of uplift charges.[310]

Stakeholders consulted with as part of the AEMC's Scoping Study noted that while AMDQ provides participants that have an allocation with some protection against congestion uplift charges, AMDQ cannot be used to hedge against surprise or common uplift charges. Reference was also made in this context to the ASX Victorian Wholesale

305 These products are currently: (1) Victorian wholesale gas futures (in units of 100 GJ of natural gas per day over the period of a calendar quarter); (2) Victorian wholesale gas strip futures (units are four Victorian wholesale gas futures contracts); and (3) Strip options over Victorian wholesale gas futures (an option over four predetermined Victorian wholesale gas futures contracts).

306 Ex ante prices are set at 5 discrete times during the gas day in the DWGM (6.00am, 10.00am, 2.00pm, 6.00pm and 10.00pm) . See: Appendix F.

307 ASX Victorian Wholesale Gas Futures contracts are cash settled using the arithmetic average of the beginning of the day (6.00am) price for the Victorian wholesale gas market over the period of a calendar quarter.

308 Unlike contract carriage pipelines, shippers utilising the DTS cannot reserve firm capacity. They may, however, have an AMDQ allocation or an AMDQ cc, which provide them with a hedge against congestion uplift charges. AMDQ and AMDQ cc (and the rights they provide holders) are outlined in detail as part of Appendix F.

309 Uplift charges are further discussed in Appendix F.

310 Victorian Government, *Gas Market Taskforce*, Supplementary Report, October 2013, p. 105.

Gas Futures product, but participants stated this product can only be used to hedge against the ex ante market price and not uplift charges and was not therefore widely used.[311]

Stakeholders also noted that the methodology used to allocate congestion uplift charges in the DWGM should be reviewed to determine whether it is consistent with the 'causer pays' principle, particularly in those circumstances where the ancillary payments have been incurred as a result of a system constraint or supply source failure and participants without a hedge have been withdrawing gas in line with their schedule.[312]

In the ESAA's assessment of the east coast gas market stakeholders stated that prices on the DWGM (and STTM hubs) primarily reflect daily imbalance positions of market participants, rather than underlying conditions of supply and demand. Stakeholders suggested that the observed market prices may therefore provide some insight to a potential new entrant, but are likely of little value in terms of actual benchmarks for contract negotiations. Overall, stakeholders suggested that the facilitated markets have had little impact on transparency in the commodity and transport markets.[313]

Stakeholder submissions

Risk management and price transparency was a key theme emerging in submissions received. Issues raised largely fell within the following two categories:

1. Ex ante prices in the DWGM do not reflect all costs (ancillary payments) and impede the development of risk management products; and
2. Uplift payments not allocating "costs to their cause."

Ex ante prices in the DWGM do not reflect all costs (ancillary payments) and impede the development of risk management products

Many parties that made submissions were of the view that the current ancillary payment/uplift charging regime in the DWGM was complex and that these costs should be incorporated in the observed market price. Many submitters were of the view that this would encourage the development of risk management products.

ERM Power states that the DWGM is far more complex than the STTM and Wallumbilla GSH, particularly the settlement process and believe that its complexity could be simplified considerably via the ancillary payment/uplift calculation processes. ERM Power point to these processes being explained in four AEMO procedural documents which total 144 pages with numerous complex algorithms.[314]

ERM Power proposes a move away from the current unconstrained pricing regime (with ancillary payment/uplift charges) because it exposes market participants to risks they cannot manage.[315] ERM Power added that if all costs were reflected in the spot price, swaps and other derivatives (eg the ASX products) would be more effective in

311 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 95.

312 K Lowe Consulting, *Gas Market Scoping Study,* a report for the AEMC, July 2013, p. 97.

313 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform,* May 2013, pp. 58 & 60.

314 ERM Power, Discussion Paper submission, p. 7.

315 ERM Power, Discussion Paper submission, p. 6.

allowing participants to manage their risks. ERM Power states that if all costs (or the majority of costs) were reflected in the spot price, the attractiveness of financial hedging in the DWGM would increase.[316]

While AGL's view is that the DWGM is generally best left alone, it also states that there is significant complexity and risk in the ancillary payments/uplift charge process. AGL would welcome a review of these charges with the aim of reducing market participants' transaction costs and pricing risks.[317]

GDFSAE states moving to an arrangement whereby the costs associated with ancillary payments are embedded in the market price (providing participants a “clean” price signal) will encourage greater levels of participation and liquidity.[318] In an industry statement presented to the AEMC, the signatories also noted these points stating that the current situation of multiple market designs make trading complex and inefficient and that it differs to a widely accepted market with “clean” prices that encourages greater participation and liquidity.[319]

The ESAA also notes that the complexity of ancillary payments and uplift charges could be reduced via linking them to the market price and that this could improve participants’ ability to assess and manage risk. The ESAA consider this would likely improve the value and uptake of risk management products such as those offered by the ASX and increase market transparency.[320]

Origin Energy, like ERM Power and GDFSAE, suggests that the current pricing structure is not truly reflective of market costs and a key means to manage risk in the STTM and DWGM is to ensure all market costs are incorporated in the price. Origin Energy notes that there are a number of prices on any given day, which increase operating costs and give rise to risks that cannot be effectively hedged. In the DWGM this could take the form of linking ancillary payments back to the market price, which would improve the ability of market participants to assess and hedge risk (and make ASX products more highly traded).[321]

Uplift payments not allocating “costs to their cause”

ERM Power disagrees that the allocation of ancillary payments is currently done on a “cost to causer” basis, particularly for congestion uplift. ERM notes that "when ancillary payments are generated, a portion of the total cost is always allocated as congestion uplift with the residual being allocated as surprise and common uplift, regardless of the nature of the event that has caused the cost".[322]

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316 ERM Power, Discussion Paper submission, p. 7.

317 AGL, Discussion Paper submission, p. 5.

318 GDFSAE, Discussion Paper submission, pp. 8-9.

319 Industry Statement, Discussion Paper submission, p. 3. Note: the Industry Statement was supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association.

320 ESAA, Discussion Paper submission, p. 7.

321 Origin, Discussion Paper submission, pp. 2-3.

322 ERM Power, Discussion Paper submission, pp. 3-4.

ERM Power further states that congestion uplift charges unfairly penalise small market participants and new market entrants. It is suggested that current market forecasts (supply shortages) make it very difficult for these parties to secure the right combination of physical supply and AMDQ cc/AMDQ to give effect to a congestion hedge.[323]

ERM suggests that a rule is made that removes congestion uplift changes and makes all ancillary payments recoverable through common and surprise uplift charges.[324]

6.2.3 Transaction costs associated with the value adding market functions

Costs incurred by AEMO in its role as operator of the DWGM are recovered from participants by charging a fee for gas withdrawn from the DTS. Since participation in the DWGM is mandatory for parties wishing to withdraw gas, this fee reflects an unavoidable transaction cost for these parties.

The fee is currently $0.082/GJ for the DWGM and is budgeted to rise 7 per cent in 2015-16.[325] AEMO has reported that expenditure in 2015-16 is expected to be $21.8 million with approximately 65 per cent of this comprised of labour costs ($14.1 million).[326]

In general, the costs associated with a centrally administered market should primarily be recovered from the beneficiaries of those markets via the trades that have occurred as a direct result of the market being in place.

As can be seen from Figure 6.1, the majority of gas transacted through the DWGM is by participants who are selling gas into the market and at the same time buying it back. This is because, while the DWGM is compulsory, most participants have underlying gas supply agreements in place and do not need to use the DWGM for the majority of their needs.

As noted in section 5.2.3, markets create value through bringing together buyers and sellers to trade amongst one another. As such, trades occurring between the same entities in the DWGM should not be considered part of the “value” that the market creates. These transactions are occurring because of the compulsory nature of the DWGM and would occur in its absence. In other words, the DWGM provides no additional benefit to market participants for within-participant trades.

As with the STTM, where the DWGM creates value is by facilitating ex ante commodity trades and ex post deviation trades with other market participants. This includes small retailers or other users that have no upstream contracts or are supplementing existing contracts by purchasing small volumes of gas on the DWGM (say, as a result of greater than forecast residential demand). These types of trades have historically accounted for approximately 20 per cent of total volumes transacted in the DWGM, as shown in orange in Figure 6.1.

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323 ERM Power, Discussion Paper submission, p. 4.

324 ERM Power, Discussion Paper submission, p. 5.

325 AEMO, *Consolidated Draft Budget and Fees: 2015-16*, Published March 2015, p. 14.

326 AEMO, *Gas Market Draft Budget and Fees 2015 - Vic Wholesale Gas and Vic Gas FRC*, March 2015, p. 8.

If the annual costs of operating the DWGM were only recovered from gas that is traded for the purposes of settling ex ante commodity trades and ex-post deviation trades, the historical AEMO fee rises from approximately $0.07-0.09/GJ to approximately $0.35-0.40/GJ for the DWGM, as shown in Table 6.1 below. These indicative cost estimates are relatively high in the context of gas prices typically observed in the DWGM of around $4/GJ (ie approximately 10 per cent). It also does not include the costs associated with the time and resources individual firms must dedicate to operating in the DWGM, or the effects of any penalties (like uplift payments).

Table 6.1 AEMO $/GJ DWGM fees would be significantly higher if levied only on ex ante commodity and ex post deviation trades

	2010-11	2011-12	2012-13	2013-14
AEMO expenditure ($m)	16.6	17.2	18.1	20.4
Total withdrawals (PJ)	232.2	220.5	228.3	224.2
Ex ante commodity and ex post deviation trades (PJ)	44.4	43.1	53.1	55.7
Implied AEMO fee ($/GJ) – based on total DWGM transactions*	0.07	0.08	0.08	0.09
Implied AEMO fee ($/GJ) – based on ex ante commodity and ex post deviation trades	0.37	0.40	0.34	0.37

Source: AEMC analysis using AEMO supplied expenditure and gas trade data.

* Note that prior to 1 July 2014, the tariffs for Tariff D and Tariff V customers were separately specified. We have estimated the implied tariff for *all* customers for the years in the above table to ensure a consistent comparison to the current $0.082/GJ rate for all customers.

The current structure for recovering AEMO's costs of operating the DWGM has, arguably, resulted in those trading mostly in balance (where injections equal withdrawals) being charged a disproportionate amount, relative to those who rely more on the ex ante commodity and balancing functions. This is evident historically in the difference between the market fees of approximately 7 – 9 cents per GJ and the approximate 35 – 40 cents per GJ that would have been levied if the costs of the market were only recovered from the trades facilitated by the DWGM.

Observations from previous reviews

In the Scoping Study, most stakeholders noted that the DWGM provides an effective mechanism for trading imbalances and were of the view that the movement to ex ante intra-day trading in 2007 was a positive step forward.[327]

The Victorian Gas Market Taskforce stated that the DWGM spot market has not been successful in stimulating commodity trading of gas (relative to the UK's National Balancing Point). In particular, the review referred to the fact that gas is sold to retailers under bilateral contracts and only bid into the market by those retailers and so the spot market is used as a balancing market only, which was stated to underutilise the potential of the DWGM to achieve greater transparency and efficiency.[328]

Views expressed on the facilitated markets in general as part of the ESAA's assessment of the east coast gas market prepared by Deloitte were largely that out of contract trades made up only a very small proportion of total trades on these markets. Stakeholders indicated that actual trading activity *between* participants on the facilitated markets is relatively limited, with the markets primarily serving the function of balancing mechanisms, rather than as an alternative wholesale source of gas to their upstream contracts.[329]

The ESAA review estimated that most wholesale buyers would typically contract up to around 95 per cent of their expected demand requirements on the STTM hubs and around 80 per cent on the DWGM (possibly less in the case of smaller retailers). A cost of $0.50/GJ traded was estimated as part of this review for the DWGM based on an assessment of volumes traded, deviation costs and market revenue requirements.[330]

Discussions with stakeholders as part of the ESAA review suggested that higher levels of out of contract trading on the DWGM than the STTM hubs relate primarily to the perception of the DWGM as a more mature and less risky market for the following reasons:[331]

- Higher liquidity, with significantly more gas withdrawn and traded on the DWGM than in the STTM hubs combined, plus the ability to adjust trading positions during the gas day with intra-day trading.
- More opportunities for managing operational risks, with the ability to enter into contracts with storage providers (including LNG) for on call injections or withdrawals.
- A co-ordinated approach to market and transmission scheduling. AEMO is responsible for both market scheduling and operation of the DTS. This dual role

327 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 95.

328 Victorian Government, *Gas Market Taskforce,* Supplementary Report, October 2013, p. 79.

329 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, p. 44.

330 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform,* May 2013, p. 61.

331 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform,* May 2013, p. 45.

reduces the risk of pipeline allocations differing from the market schedule as can occur in the STTM hubs.

- The demand profile of wholesale buyers in Victoria, where there is a greater proportion of (less predictable) residential demand relative to all other STTM hubs (with the possible exception of Adelaide).

While overall trading outside of contractual arrangements was stated to be limited, a number of stakeholders noted in the ESAA review that the facilitated markets have played a key role in supporting the entry of new retailers on the east coast. In particular, it was noted that the ability to obtain access to gas in the initial phase of market entry without needing to commit to a long-term GSA and GTA in the DWGM was critical to getting a foot-hold in the retail market, and developing the experience and scale necessary to enter into a long-term GSA and GTA.[332]

The Eastern Australian Domestic Gas Market Study notes that the DWGM was designed to complement long-term gas contracts and provide an option for making up short run supply and demand shortfalls. The report identifies that the DWGM currently trades insignificant gas volumes and may have only a limited relevance to the price of the long-term gas contracts.[333]

Stakeholder submissions

High cost associated with the valuing adding functions of the DWGM

Most stakeholders submitted that the facilitated markets are generally working well and provide an effective mechanism to trade imbalances. However, many also noted that the DWGM (like the STTM) provides a mandatory balancing market that participants must use and pay for, regardless of whether there is intent to use the balancing services or not.

APGA noted that gas traded on the facilitated markets represents only a very small portion of the total traded at the wholesale level, which is primarily conducted through bilateral contacting.[334] APGA quote trading in balancing gas as making up approximately 13 per cent of the DWGM in 2014-15 and, that if the current $0.08/GJ gas fee was spread over just the balancing gas, the cost would increase to approximately $0.61/GJ.[335] APGA note that the current fee structure results in participants that do not need to use the balancing service are subsidising those that do.[336]

Similarly, ESAA also notes that the DWGM and STTM hubs impose relatively high costs per GJ traded on account of the low volume of gas traded, with market participants generally seeking to closely match their own injections and withdrawals to minimise exposure to significant financial risks that cannot be hedged. ESAA refers to an estimate of approximately $0.50/GJ traded for the DWGM from the 2013 report

332 ESAA, *Assessment of the East Coast Gas Market and Opportunities for Long-Term Strategic Reform*, May 2013, pp. 45-46.

333 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 64.

334 APGA, Discussion Paper submission, p. 11.

335 APGA, Discussion Paper submission, p. 34.

336 APGA, Discussion Paper submission, p. 30.

ESAA commissioned Deloitte to produce (discussed below). ESAA noted that reducing transaction costs is essential to improve trading and liquidity and ensure the facilitated markets deliver value to market participants in the future.[337]

AGL notes that the facilitated markets are essentially balancing arrangements in downstream distribution networks and that "the [facilitated] markets are characterised by complexity and resultant overhead costs which culminate in a service cost per GJ, particularly in the STTM, which overwhelm any value to be had from trading in the market".[338]

6.3 AEMC's Stage 1 findings

This section details our assessment of the DWGM and future opportunities for the development of the market. These opportunities primarily stem from the increasing maturity of the east coast gas market, together with the changes driven by LNG exports, and draw on issues raised in submissions and observations from earlier reviews. The future development opportunities will form the basis of the analysis undertaken as part of Stage 2 of this review.

We also outline Stage 1 recommendations consistent with the terms of reference, which represent 'no regrets' changes where implementation can begin immediately, irrespective of the future development of the DWGM and its role in the broader east coast gas market framework.

6.3.1 Future opportunities to develop the market

The DWGM was developed at a time when the east coast gas landscape looked very different to what it does today. In 1999, there were no STTM hubs operating in other state capital cities, no voluntary gas supply hubs being developed and no LNG trains being built in Queensland. The Victorian system operated in isolation from the rest of the east coast by virtue of it not being physically connected to the rest of the east coast pipeline transmission system.

The market was originally designed to meet two broad objectives, namely:

1. to support full retail competition (new entrant retailers can purchase gas at the spot price); and
2. to encourage diversity of supply and upstream competition (transparency of pricing expected to encourage the development of new sources of supply and upstream competition).

Today, the DWGM is generally regarded by participants as providing an effective and competitive gas balancing service and facilitating trading of gas in Victoria based on short-term prices, albeit in a complex and high cost manner.

While the original market design has been developed on an incremental basis since market-start, the underlying fundamental structure remains unchanged – a set of

337 ESAA, Discussion Paper submission, p. 3.

338 APGA, Discussion Paper submission, p. 1.

arrangements designed to offer a balancing trading service, a spot commodity trading service and to allocate capacity on the DTS.

The mandatory nature of the DWGM results in only a small portion of total gas "traded" on the DWGM actually benefiting from the market arrangements directly. This was commonly referred to by stakeholders as part of this review, as well as in the observations from previous reviews undertaken.

The complexities associated with the current market design may impose disproportionate administrative costs on the market, particularly when considering the small proportion of trades that the DWGM facilitates. Participants who trade within their bilateral contracts also incur a fee for participating in the market, irrespective of whether they have derived any value from the arrangements.

The DWGM also represents an added level of complexity for entities wishing to operate both inside and outside of Victoria since it is characterised by a different set of market arrangements to the STTM hubs operating in other demand centres, although the practical roles of each market are similar.

Submissions to this review and the observations from previous reviews have largely reiterated the sentiment that the DWGM is a complex and costly market, relative to the value it adds.

The emergence of a number of different gas trading arrangements on the east coast (STTM hubs and the gas supply hub at Wallumbilla as well as potentially at other locations in the future), coupled with the onset of fundamentally changing supply-demand conditions resulting from the advent of LNG exports in Queensland, suggest it is an opportune time for reflection on the efficacy of the DWGM in its current state, as well as the facilitated markets more generally.

In particular, we consider there is an exercise that needs to be undertaken in considering whether:

1. the originally stated DWGM objectives remain relevant in the contemporary east coast market and whether the current market design is achieving those objectives efficiently; and
2. if not, whether the objectives and design of the DWGM need to be re-focussed, taking into account developments in the broader east coast market and the DWGM role alongside other facilitated markets.

We consider there is merit in progressing this issue as part of Stage 2 of the review. We anticipate this will involve consultation with stakeholders around the type and number of facilitated markets on the east coast and how best to develop the markets such that they meet their objectives and the needs of participants. We anticipate this will include investigating the scope for increasing the consistency in gas market designs across the east coast to minimise complexity and transaction costs, where practicable.

6.3.2 Stage 1 recommendations

As part of Stage 1 of the East Coast Review and the Victorian Review, we consider it prudent to consider whether there are any existing issues that can be resolved with the intention of better placing the DWGM to achieve the NGO, irrespective of what future shape the facilitated market arrangements in Victoria take (the outcome of Stage 2).

Specifically, the AEMC has considered issues raised in submissions and applied its own analysis and assessment framework outlined in chapter 2 to arrive at the following two Stage 1 recommendations:

1. remove limitation in the NGL on who can submit DWGM rule changes; and
2. harmonise gas day start times.

Each of these is discussed below.

Remove limitation in the NGL on who can submit DWGM rule changes

Section 295(3) of the NGL currently provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.

Lumo Energy stated in its submission that the rule that prevents anyone other than the Victorian Government and AEMO from submitting a DWGM rule change to the AEMC should be amended to be consistent with arrangements in the STTM.[339] Similarly, GDFSAE considers that the rule change processes should be consistent across markets and aligned between gas and electricity.[340]

The current NGL restriction on who can submit a rule change applying to the DWGM was raised in the Victorian Gas Market Taskforce review. In particular, as part of the Gas Market Taskforce review stakeholders stated that engaging with the AEMO rule change processes is a time and resource consuming exercise. The process was stated to lend itself to major gas market participants and represent a barrier for smaller market participants and potential new entrants to influence market development. While the Gas Market Taskforce review did not come to a position on these issues, it recommended that the Victorian government consider the merits of revisiting the NGL section 295(3) and the appropriateness of adopting an open standing rule change process for the DWGM, as has been done in the electricity sector.[341]

The AEMC note that the restriction on who can submit a rule change request for the DWGM was also raised in submissions to the 2013 AEMC Gas Market Scoping Study. In particular, this limitation was claimed by many stakeholders to be unnecessary and in direct contrast to the STTM, where any party can initiate a rule change request. Some stakeholders also noted that it can result in sub-optimal outcomes because AEMO's consultation process tends to be consensus driven and dominated by the larger players.[342]

To address these issues, we recommend that the restriction be removed. This would mean that any party would be able to propose rule changes applying to the DWGM, in manner consistent with the arrangements applying to the STTM, as well as those applying to the electricity sector through the NER.

339 Lumo Energy, Discussion Paper submission, p. 17.

340 GDFSAE, Discussion Paper submission, p. 4.

341 Victorian Government, *Gas Market Taskforce,* Supplementary Report, October 2013, pp. 79-80.

342 K Lowe Consulting, *Gas Market Scoping Study,* a report for the AEMC, July 2013, p. 95.

Harmonise gas day start times

As noted in section 5.3.2, a large number of submissions to this review called for the harmonising of gas day start times across the east coast (or referred to the harmonising of market parameters more broadly).[343] The inconsistency between gas day start times was also raised by stakeholders as part of the 2013 AEMC Gas Market Scoping Study and it was suggested that the gas day start times be aligned.[344]

As outlined in section 5.3.2, the final Stage 1 recommendations of this review could include a rule change that the Energy Council could submit to align gas day start times, given the widespread support shown for such a change to-date through submissions to the Discussion Paper.

We would be interested in the views of stakeholders regarding the practicalities of implementing such a change, in particular whether gas day start times should be harmonised across gas markets alone (and, if so, what time should be selected and why), or whether this harmonisation should also include the electricity market (ie aligning the gas day start times with the 4.00am day start time in the NEM).

We are also interested to hear views on any costs that may accompany this change, for example the amendment of existing bilateral contracts and the recalibration of metering systems.

The AEMC note that most submissions to this review (as well as previous reviews) that called for harmonising of gas day start times across the east coast also called for consistency in a number of other market parameters, such as market price caps, trading periods, settlement periods and consolidating prudential requirements.

The AEMC is of the view that these market parameters are more fundamentally linked to the overall market design. The AEMC's preliminary view is therefore that these additional market parameters/design aspects should be considered as part of a more thorough consideration of the role and design of the facilitated markets on the east coast (undertaken in Stage 2 of this review). The AEMC would appreciate the views of stakeholders on whether any harmonisation across the facilitated markets beyond the gas day should be progressed in Stage 1 of this review.

343 See for example submissions received from Origin, Santos, QGC, APGA, Alinta, GDF, Arrow Energy, ESAA and the industry statement (supported by the following companies and associations: GDFSAE; Stanwell; APLNG; Arrow Energy; EnergyAustralia; QGC; Alinta Energy; High Voltage Brokers; Total Gas & Power Limited; Energy Users Association; and the Plastics & Chemicals Industries Association).

344 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 97.

7 Gas Supply Hub

Box 7.1 Summary of findings and recommendations

While only being operational for around a year, market participants are generally of the view that the Wallumbilla gas supply hub (GSH) provides a simple and low cost platform for the commodity trading of gas. However, the market is still in its infancy and the volume of trades occurring at the hub is still developing.

As the Wallumbilla GSH matures, consistent with any fledging market, there will be refinements to the initial market design that need to be made. An example of this can be seen in AEMO's work to consolidate the three current trading locations into a single location design. In this context, the AEMC notes the following two technical workstreams AEMO is currently undertaking:

1. establishing a single trading zone/product at Wallumbilla (including the hub services required to support this); and
2. the technical design of a GSH at Moomba.

As part of Stage 2 of this review, we consider there is merit in complementing AEMO's technical workstream by analysing the potential for competitive outcomes to emerge in hub services at Wallumbilla (including the possible need for economic regulation).

More broadly, we will review the role of the Wallumbilla GSH going forward as part of the wider east coast market in Stage 2. The AEMC will consider how the Wallumbilla GSH can best interact with other facilitated markets going forward and potential future development opportunities.

We note the general consensus regarding establishing a second GSH at Moomba at some point, but also that parties hold divergent views as to the effect doing so now will have on liquidity and, hence, the appropriate timing for establishing a Moomba trading location.

The AEMC will be working closely with AEMO as it develops a conceptual design of the Moomba GSH. As part of Stage 2, we will consider how and when such a design will best fit into the wider east coast framework, including an assessment of the likely effect on liquidity in the broader market.

7.1 Market overview

In December 2012, SCER (now the COAG Energy Council) announced that a new voluntary brokerage GSH would be established at Wallumbilla by March 2014.[345] SCER requested AEMO develop this hub to enhance transparency and reliability of gas supply by creating a voluntary market that offers a low-cost, flexible method to buy and sell gas at interconnecting transmission pipelines.[346]

345 SCER Communiqué, 14 December 2012.

346 AEMO website, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub.

Wallumbilla was selected as a location for the supply hub because it is located in close proximity to significant gas supply and demand and is a major transit point between Queensland and the gas markets on Australia's east coast. Wallumbilla marks the intersection of the Roma to Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

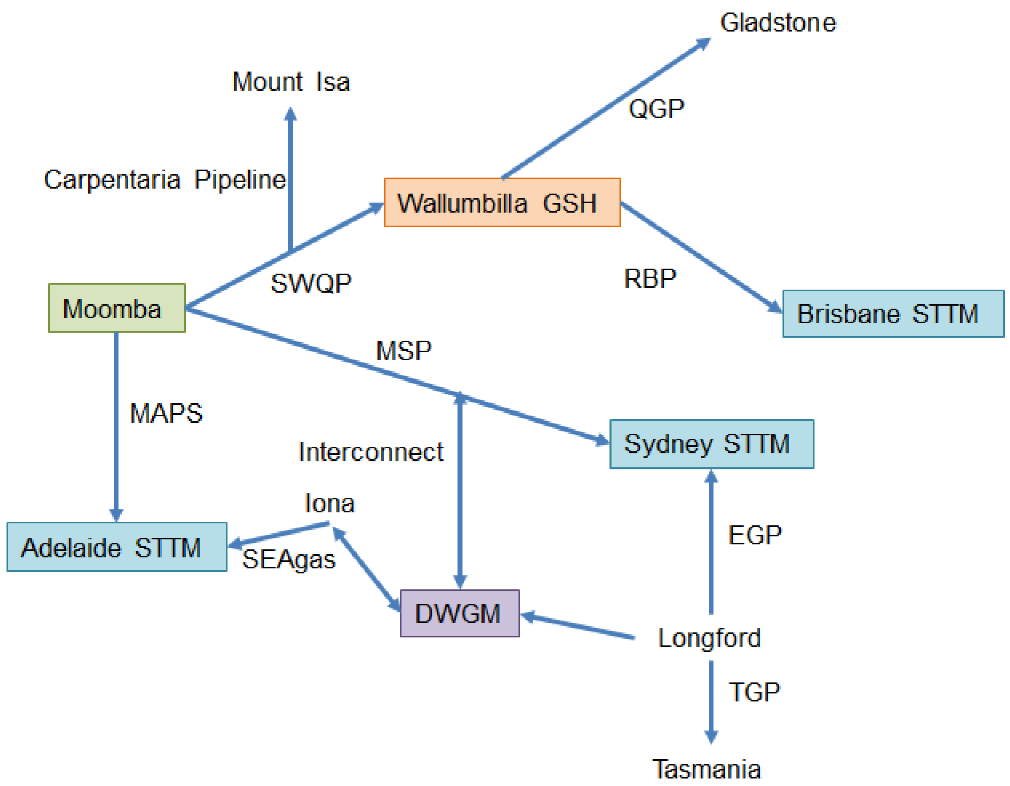
Figure 7.1 below illustrates how Wallumbilla acts as a transit point for major gas fields and a supply point for demand centres in Gladstone and Brisbane, and is located near gas storage facilities and gas-powered generation, making it a natural point of trade.

Figure 7.1 Location of the Wallumbilla supply hub

Source: AEMO, Gas Supply Hub Industry Guide, March 2014, p. 2.

An overview of how the three pipelines intersecting at Wallumbilla fit in with the east coast gas markets more broadly is shown in Figure 7.2.

Figure 7.2 Overview of the Wallumbilla supply hub and other east coast gas markets



Source: AEMC analysis.

AEMO who was accorded responsibility for the design of the market, at the time of development stated that it expected the implementation of this hub to:[347]

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.

Overall, the market was designed to provide a reference price that would support a financial derivative market to manage risk, guide investment and transaction decisions, facilitate trading through standardisation of contracts, and encourage secondary pipeline capacity trading.[348]

Products traded on the Wallumbilla GSH are for the sale and purchase of gas delivered at one of the three major connecting pipelines at Wallumbilla, ie the RBP, the QGP and the SWQP pipelines (as outlined in Figure 7.2 above). A "trading location" has been established for each of these pipelines by grouping delivery points (either physical or virtual) to which gas is delivered and where title is transferred from a seller to a buyer.

347 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p. 4.

348 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p. 4.

There are currently four trading products on offer, all of which are available separately for each of the three trading locations. These products are for:[349]

- balance-of-day (today);
- day-ahead (tomorrow);
- daily (two to seven days ahead); and
- weekly (next four weeks).

Since the market has been in operation there has been between five and eight participants per month trading on the Wallumbilla GSH. The hub has been responsible for 2.9 PJ of traded gas from market-start until the end of February 2015, which, at a volume weighted average price of $2.64/GJ, equates to approximately $7.7 million in trades.[350] The 2.9 PJ traded over the 11 months since the GSH began represents approximately 1 per cent of total gas consumption in Queensland during 2014.[351]

To date, all trades have occurred at the RBP and SWQP nodes. While we note that the vast majority of trades to date have occurred at the RBP node,[352] those trades occurring at the SWQP node do not appear to be significantly different to those at the RBP node, as shown in the Figure 7.3. That is not to say this will continue going forward, particularly as trades emerge at the QGP pipeline. Further, the pattern of prices in the period following the first exports of LNG from Queensland in late 2014[353] differs notably from the period preceding these exports.

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349 We understand from AEMO that it is also intending to list a monthly forward dated product later in 2015. A greater description of the products available can be found in Appendix G.

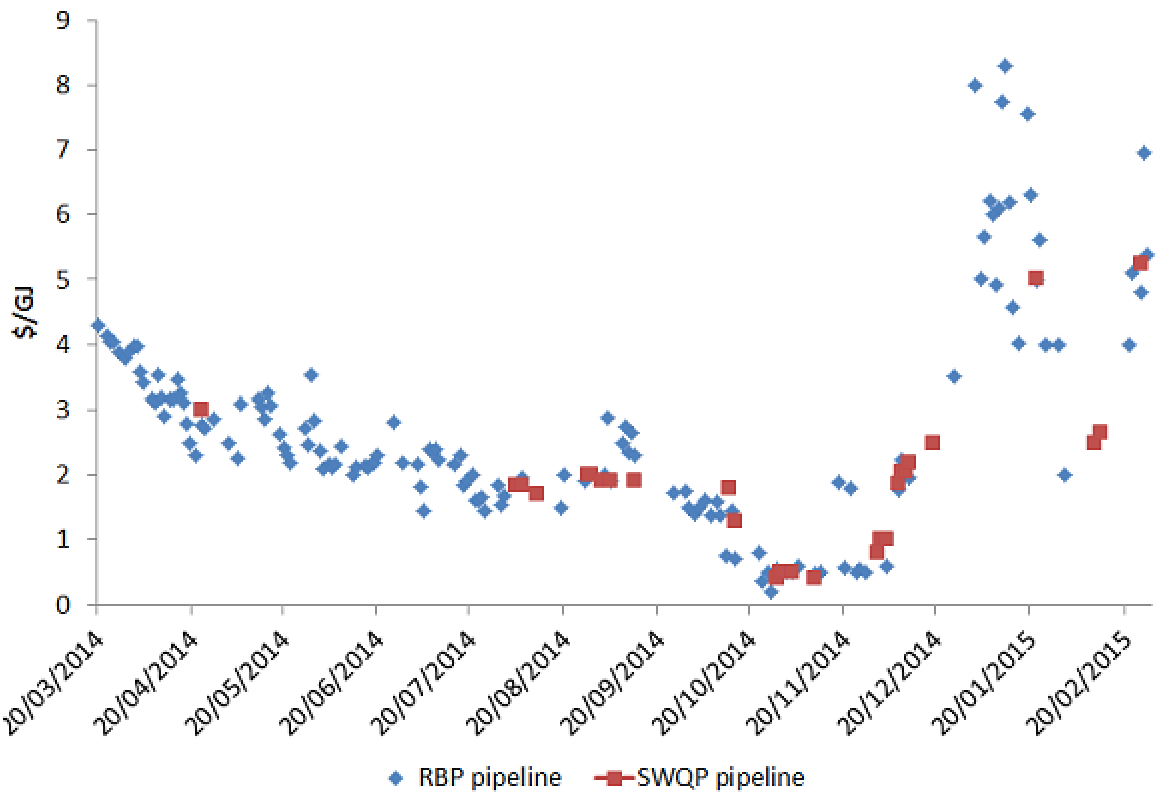
350 AER Wholesale Statistics, available at: http://www.aer.gov.au/node/29333

351 Total gas consumption for Queensland in 2014 was estimated to be 266 PJ, see: EnergyQuest, *Energy Quarterly*, March 2015, Figure 44, p. 108.

352 The RBP pipeline delivers gas to the Darling Downs, Swanbank and Braemar 1 & 2 gas-fired generators. We understand that most trades have occurred at the RBP delivery point with trading between participants who have excess gas from these generators selling to opportunistic buyers who have the capacity to transport and store this excess gas.

353 BG Group began loading its first LNG cargo from QCLNG on 28 December 2014. See: QGC website, available at: http://www.qgc.com.au/news-media/NewsDetails.aspx?Id=5630.

Figure 7.3 Majority of trades to-date have occurred at the RBP node



Source: AEMC analysis on AER, Wholesale Statistics.

On 31 March 2015, the ASX and AEMO announced the launch of ASX Wallumbilla natural gas futures, which started trading on 7 April 2015. It was noted at the time that "participants will be able to use the Wallumbilla Gas Supply Hub Benchmark price as a basis price for their gas contracts, with the development of a derivatives market providing a risk management tool for forward pricing and planning."[354] The AEMC understand that neither of these futures products have traded to date.

Overall, while only being operational for approximately one year, market participants are generally of the view that the Wallumbilla GSH provides a simple and low cost platform for the commodity trading of gas.

7.2 Key issues in the Gas Supply Hub

At the time the Energy Council decided to proceed with the implementation of the GSH, it also decided that a review of the model should be carried out in 2015 to consider opportunities for refinements based on operational experience, and if necessary and beneficial, consider the introduction of hub services, particularly redirection services, to

354 ASX Media Release, 31 March 2015, available at: http://www.asx.com.au/documents/asx-news/ASX-AEMO_Launch_Wallumbilla_Gas_Futures.pdf

assist trading gas between nodes.[355] In keeping with this decision, AEMO is currently undertaking a substantial body of work to develop the GSH.

Aside from the current AEMO workstream, this review represents the first review of the GSH as part of the wider east coast gas market since it commenced operation in March 2014.

The following sections set out the key issues that have been identified for the GSH, drawing on the work AEMO has done to date, submissions to this process and analysis undertaken by the AEMC. The issues are presented in two categories, consistent with the AEMO workstreams:

1. establishment of a single trading zone/product at Wallumbilla (including the hub services required to support this); and
2. development of a GSH at Moomba.

These are each discussed in detail below.

7.2.1 Establishment of a single trading zone/product

Because the three pipelines servicing Wallumbilla (RBP, SWBP, QGP) are not physically connected, parties currently have to deliver/receive gas from trading locations specific to each of these pipelines. There is currently no means to trade gas over the entire area that the hub encompasses.

Having multiple trading locations (products) for essentially the same commodity traded within a small geographical area divides potential buyers and sellers of gas, making it more difficult to match buyers and sellers, limiting the trading liquidity. In 2012, it was estimated that investment in capacity to enable gas to flow between the facilities at Wallumbilla for a single trading model to operate successfully was approximately $118 million.[356]

AEMO is currently in the process of undertaking a review of the Wallumbilla hub with the objective of facilitating more efficient market outcomes through increased trading liquidity and participation at Wallumbilla. AEMO is investigating the development of a single product, which will support market development through:

- establishment of single reference price for the value of gas traded at Wallumbilla; and
- standard location for delivery of physical transactions.

Specifically, AEMO is developing models that could pool potential buyers and sellers together within a single market, including:

1. Single Facility – grouping the delivery points on one pipeline with high throughput (eg, SWQP) to form the hub definition.

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355 COAG Energy Council website, available at: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/gas-supply-hub-trading-market/

356 AEMO, *Gas Supply Hub – Cost and Scoping Report*, 4 May 2012, p. 24.

2. Group Physical Locations – grouping the delivery points on a small number of facilities with high throughput (eg, the SWQP and RBP) to form the hub definition.
3. Single Trading Zone – define the hub as one virtual trading point that encompasses all gas flowing through Wallumbilla (eg, SWQP, RBP and QGP).

AEMO will review these models and assess their feasibility for implementation at Wallumbilla. AEMO has developed principles that will guide development of the Wallumbilla GSH and provide a benchmark to assess design options.[357]

AEMO is also investigating the need for a balancing arrangement to succeed the current arrangements (ie primarily contract-based balancing), given that AEMO considers the physical risk could be greater under a single product model due to the increased challenge of delivering trades across the hub.

The Wallumbilla GSH does not currently offer the types of hub services (eg balancing, storage, compression and redirection), offered at some other international hubs that can support trading and liquidity. Consolidation of delivery locations at Wallumbilla would require hub services to connect delivery points and facilitate trade in a single market.

Key hub services include:

- intra-hub transfer service: transfer of gas from one interconnected pipeline to another through a hub by displacement (including exchanges) or physical transfer;
- title transfer service: a permanent transfer of ownership of gas from one party to another at the same location (for example in-pipe trades);
- balancing service: to manage shipper shortfalls or a pipeline mismatch (could have multiple providers); and
- storage service: facilitates the storage (or withdrawal) of gas in a connected storage facility for use at another time.

The development of standard products for the secondary trading of capacity by industry could, in the future, allow transportation and hub services to be listed as trading products on the exchange.

Stakeholder submissions

Stakeholders were generally positive about the Wallumbilla GSH in submissions, however many noted that it had a detrimental effect on the liquidity of other markets (notably the Brisbane STTM).

ERM Power considered that removing the minimum parcel size of 1 TJ would minimise barriers to entry by encouraging smaller players, particularly new entrants, to trade in the market. ERM Power also considers the supply hub user fees are too high,

357 These principles are: (1) Trading (maximise participation, maximise liquidity, development applicable to all forms of trading); (2) Operations (standardisation of hub services, maximise deliverability (firmness), development to encourage efficient use of facilities, minimise costs, minimise complexity); and (3) Development (encourage innovation of services and financial products, encourage efficient investment).

particularly given the incremental cost for additional user accounts of $5,500 per annum.[358]

The next two sections outline the views of stakeholders on the Wallumbilla GSH development and operation to date.

Stakeholders were generally supportive of a single product at Wallumbilla

In general stakeholders were supportive of the move towards a single product at Wallumbilla.

AEMO highlighted that it is currently reviewing the potential to concentrate and develop hub services at Wallumbilla through a single product.[359] Almost all submissions that commented on the current AEMO workstream were supportive of it.

APA noted that it is working on the development of a hub service to apply at Wallumbilla that would allow trading across the three pipelines and integration of the three trading nodes into a single point. APA considers that a simple hub service provided by APA at Wallumbilla, that can be accessed by shippers that do not already have access to services at the Wallumbilla compound, would assist the market and represent a relatively low cost solution that would increase available market liquidity.[360]

Santos considers that while the Wallumbilla hub has only been in operation for one year, moving to a single trading point to pool buyers and sellers is an important and necessary step in the market's development. Santos argues intra-day trading is currently prohibitive due to the cost associated with pipeline charges, which is why little occurs.[361]

The ESAA is also supportive of developing a single trading product at Wallumbilla (including the balancing services required to facilitate the single product) with a view to improving market liquidity.[362]

Origin Energy considers the focus of the GSH should be on improving participation and liquidity. Origin Energy supports the process being run by AEMO to assess the merits of a single product at Wallumbilla, although notes the complexity and potentially large costs associated with a single trading zone.[363]

Lumo Energy supports the development of a single product at the GSH and proposes that doing so would increase the liquidity by pooling both buyers and sellers into a single market and establishing a standard location for the delivery of physical transactions, as well as a single reference price for the value of gas traded. Lumo stated it would welcome the development of well-defined and longer based structured products than what is currently available, noting that the development of a single

358 ERM Power, Discussion Paper submission, p. 10.

359 AEMO, Discussion Paper submission, p. 2.

360 APA, Discussion Paper submission, p. 18.

361 Santos, Discussion Paper submission, p. 5.

362 ESAA, Discussion Paper submission, p. 6.

363 Origin Energy, Discussion Paper submission, p. 4.

product at the GSH would help improve the liquidity and make the availability of such longer-dated products more viable.[364]

The view expressed by ERM Power differed to those parties above. ERM notes that a shipper who does not have contractual access to a particular trading location at Wallumbilla can already secure redirection services from the transmission operator to obtain access. ERM noted that it would be concerned if a single trading zone model effectively forces participants to pay for a suite of mandatory additional services they would not normally have purchased. Overall, ERM considers that there needs to be a significantly compelling case to warrant a move to a single product/trading zone model.[365]

AGL held the view that, while the lack of physical interconnection at Wallumbilla may limit any expansion in trade, its strong view is that "markets need to be encouraged and allowed to develop organically rather than be foisted on the industry." In this respect, AGL would like to see more initiatives and innovation associated with a low-cost, voluntary bilateral trading arrangement.[366]

APGA suggested that concerns raised by participants around their ability to take advantage of Wallumbilla stem from their desire to access Wallumbilla on the same or better terms than those who have underwritten the infrastructure investment.[367]

Impact on liquidity in other markets

A number of parties submitted that the Wallumbilla GSH has impacted liquidity on the STTM. In particular:

- Santos observed some change in behaviours with participants waiting for the STTM scheduling at 2.00pm before executing genuine trades via the Wallumbilla GSH. In most instances, it is assumed participants are looking for gas delivered into Brisbane and are testing whether there is sufficient liquidity at the STTM to support this.[368]
- Stanwell considered that limitations on systems and participant supply and demand withdrawal points have created barriers to trade at Wallumbilla, although “in-pipe” trades have reduced this – at a cost. Stanwell noted that ideally one market would operate in each region to maximise liquidity, and that the Brisbane STTM is reducing liquidity at Wallumbilla as participants can offer or bid at Wallumbilla knowing the STTM is available at a last resort.[369]
- Arrow Energy stated trading at RBP can impact trading on the STTM and vice versa. Arrow considers that where before clearing prices could be impacted by the

364 Lumo Energy, Discussion Paper submission, pp. 9-10.

365 ERM Power, Discussion Paper submission, pp. 9-10.

366 AGL, Discussion Paper submission, p. 3.

367 Australian Pipelines and Gas Association, Discussion Paper submission, p. 34.

368 Santos, Discussion Paper submission, p. 5.

369 Stanwell, Discussion Paper submission, p. 9.

relatively small STTM volumes, the Wallumbilla GSH now offers a more liquid and transparent alternative as a reference.[370]

Lumo Energy was of a different view and stated that trading at the GSH has not had a significant impact on trading and liquidity on other facilitated markets.[371]

7.2.2 Development of a GSH at Moomba

AEMO is currently investigating establishing another trading location at Moomba as part of its current work. AEMO has suggested that, given interconnection with other facilities, the MSP/APA compound is a natural point for a trading location.[372] Gas can currently be received from either the Moomba Gas Plant or the SWQP/QSN and flow via the APA compound to three major pipelines at Moomba: MSP, MAPS and SWQP/QSN.

AEMO is currently undertaking a project to determine:

- the level of support within industry for another GSH at Moomba;
- where the Moomba hub should be defined, ie physical points or a virtual point; and
- how a Moomba hub would affect trading at the Wallumbilla supply hub (eg liquidity).

Whether or not the establishment of a trading location at Moomba would reduce liquidity at Wallumbilla is a key issue for market participants, as detailed in submissions received (outlined below).

The AEMC will therefore work closely with AEMO as it develops a conceptual design of the Moomba GSH. We will then consider how and when such a design will best fit into the wider east coast framework, including an assessment of the likely effect on liquidity in the broader market.

We will also explicitly consider how the GSH model can more broadly interact with the other facilitated market designs on the east coast. In doing so, we will consider factors that appear relevant to the success of GSHs, such as: the proximity to supply and demand centres; the proximity to transmission pipelines; the proximity to existing facilitated markets; and any effects on the liquidity of existing markets.

Stakeholder submissions

AEMO considers that introducing another GSH location at Moomba would support short-term balancing outcomes between northern and southern gas markets on the east coast, leading to more efficient market outcomes and avoid over-investment in infrastructure. AEMO also considers that introducing the ability to trade at Moomba would likely provide participants with more trading options and, in turn, more liquidity in secondary capacity trading markets.[373]

370 Arrow Energy, Discussion Paper submission, p. 9.

371 Lumo Energy, Discussion Paper submission, p. 10.

372 AEMO, *Moomba Trading Location presentation*, 12 February 2015, slide 8.

373 AEMO, Discussion Paper submission, p. 2.

Submissions received from parties as part of this review expressed mixed views on whether or not a separate GSH at Moomba would add to, or detract from liquidity at the Wallumbilla GSH. The views expressed by parties are outlined below.

Stakeholders supportive of a Moomba GSH

Santos is supportive of a Moomba hub or other mechanism that would allow gas to be traded ex-Moomba and considers a Moomba hub would be especially important for smaller producers. Liquidity at Wallumbilla should not be a consideration as Santos considers if there is demand for an additional delivery point this should give confidence to the market as a whole, increasing liquidity in all areas.[374]

EnergyAustralia supports the development of the GSH at Moomba as a strategic location for a trading hub to support trade between Queensland, New South Wales, South Australia and Victoria. EnergyAustralia considers that the creation of a supply hub at Moomba is likely to deliver further benefits, including facilitating development of a forward market.[375]

Lumo Energy is of the view that establishing a GSH at Moomba would facilitate additional trade and that a Moomba hub is an important part of the continued evolution of the east coast gas market, providing a link between the southern and northern east coast gas markets. Lumo noted that any resulting impact on the liquidity of the Wallumbilla GSH is difficult to predict with any real certainty and urge that conclusions regarding reduced liquidity be treated with scepticism. Further, Lumo note that any negative liquidity impacts are likely to be short-term in nature and that over the longer-term both hubs will develop to be mature and liquid.[376]

The ESAA is supportive of developing a Moomba GSH as it considers it has the potential to facilitate improved participation and liquidity, noting that it would provide a trading platform for those participants situated off the MAPS and MSP. The ESAA suggest that this would provide market participants with greater optionality and potentially assist with efficient balancing of market participant portfolios. The ESAA notes that it will be important to ensure the new hub does not impose additional costs on existing GSH trading participants through increased exchange fees or increased variable transaction fees.[377]

Origin Energy sees a Moomba hub as a potentially valuable extension to the existing arrangements as long as it does not impose additional costs on existing supply hub trading participant through increases to fixed and variable fees.[378]

ERM Power supports the development of a Moomba GSH and disagree with the claim that a hub at Moomba will reduce liquidity at the Wallumbilla hub. ERM argue that the benefits of a Moomba hub in providing an opportunity for shippers on the MAPS and MSP pipelines to trade would outweigh the possibility of reduced liquidity. Subject to

374 Santos, Discussion Paper submission, p. 6.

375 EnergyAustralia, Discussion Paper submission, p. 3.

376 Lumo Energy, Discussion Paper submission, pp. 10-11.

377 ESAA, Discussion Paper submission, p. 6.

378 Origin, Discussion Paper submission, pp. 3-4

establishment costs being low and any increase in participant fees, ERM considers a Moomba hub should proceed.[379]

Epic Energy notes that imbalance trading already occurs on the MAPS, indicating a trading market for gas supply on MAPS already exists and is valued by shippers. Epic is of the view that a Moomba trading hub would provide a more transparent market for these trades and deliver value to market participants who operate outside of Queensland. Epic Energy states that if a Moomba trading hub is established then the optimal approach to take is to establish separate MAPS and APA trading locations.[380]

Qenos supports the development of the proposed Moomba GSH and notes it would be more likely to pursue gas purchases through Moomba as it is more easily connected to its facilities via the Moomba to Sydney Pipeline. Qenos believes that this would facilitate longer term gas supply offers and work to complement the short-term offers from the STTM.[381]

The Plastics and Chemicals Industries Association is supportive of fast-tracking the Moomba GSH to facilitate the supply of gas by junior producers.[382] Manufacturing Australia also believes that AEMO should develop additional gas trading hubs, such as that which has been proposed at Moomba.[383] BHP Billiton supports the development of trading hubs and noted that the Wallumbilla supply hub will assist the development of seasonal pricing.[384]

Views cautious of developing a Moomba GSH at this time

GDFSAE considers that a preferred condition for a Moomba GSH should be identified, based on a coherent east coast gas development strategy, given the concerns that such a development could reduce liquidity at the Wallumbilla GSH.[385]

Alinta considers that the creation of additional hubs is a second best option for market development that requires further consideration. While Alinta acknowledges that a Moomba hub would provide participants with an ability to buy gas that could be used to support market entry in Sydney or Adelaide, there is a question around whether another hub is required at all if existing transport costs were not so excessive. Alinta would be interested in the AEMC "assessing whether an additional trading hub may actually mask the real inhibitor to trade – the inability to transport gas within east coast markets at a reasonable price."[386]

QGC notes that introducing additional trading hubs like Moomba offers a short-term solution, but could split market liquidity at the Wallumbilla GSH and create greater price volatility (particularly when exacerbated by capacity constraints). QGC states that given the size of the east-coast market and its stage of development, there is significant

379 ERM Power, Discussion Paper submission, p. 9.

380 Epic Energy, Discussion Paper submission, p. 4.

381 Qenos, Discussion Paper submission, p. 5.

382 Plastics and Chemicals Industries Association, Discussion Paper submission, pp. 7-8.

383 Manufacturing Australia, Discussion Paper submission, p. 6.

384 BHP Billiton, Discussion Paper submission, pp. 2-3.

385 GDFSAE, Discussion Paper submission, p. 10.

386 Alinta Energy, Discussion Paper submission, p. 6.

benefit in concentrating trading/liquidity at one trading point (ie Wallumbilla) as it will provide sufficient depth to enable the establishment of an efficient reference price, which is necessary if the ASX proposed futures contract market is to be successful. QGC states that developing an effective futures market is in the long-term interest of consumers.[387]

QGC suggests that rather than establish a new pricing point at Moomba, a new GSH delivery/receipt point is established and trades are referenced to Wallumbilla. QGC supports ensuring that market frameworks enable new participants to enter the GSH and Moomba is an obvious delivery point for end-users with positions in the southern markets to access supply.[388]

With respect to another hub at Moomba, Stanwell argues this would reduce liquidity at Wallumbilla and that it would be better to design market arrangements to improve liquidity at Wallumbilla; or develop a virtual hub between Wallumbilla and Moomba.[389]

While APA did not comment directly on the likely level of demand at a Moomba hub, it notes that the incremental costs to implement an additional hub appear to be relatively small, but that its potential impact on liquidity at Wallumbilla should be assessed before proceeding.[390]

7.3 AEMC's Stage 1 findings

This section details the AEMC’s assessment of the current GSH at Wallumbilla and future opportunities for the development of the market via a possible Moomba GSH. The future development opportunities will form the basis of the analysis undertaken as part of Stage 2 of this review.

There are no Stage 1 recommendations for the GSH, largely as a result of the GSH framework having only been in existence for approximately one year.

7.3.1 Future opportunities to develop the market

We note the following two technical workstreams AEMO is currently undertaking:

1. establishing a single trading zone/product at Wallumbilla (including the hub services required to support this); and
2. the technical design of a GSH at Moomba.

The AEMC is working closely with AEMO throughout the completion of these two workstreams. The AEMO workstreams focus on the detailed design and operational features of both the Wallumbilla GSH and the potential Moomba GSH. This work will provide crucial input to our consideration of the optimal role of the GSH market frameworks in the wider east coast gas market.

387 QGC, Discussion Paper submission, p. 5.

388 QGC, Discussion Paper submission, p. 5.

389 Stanwell, Discussion Paper submission, p. 6.

390 APA Group, Discussion Paper submission, p. 19.

Wallumbilla GSH

Wallumbilla acts as a collection point for major gas fields and a supply point for demand centres in Gladstone and Brisbane, and is located near gas storage facilities and gas-powered generation, making it a natural point of trade. For this reason, it is generally considered that the Wallumbilla GSH was a sensible choice of location of the first GSH on the east coast.

While only being operational for approximately one year, market participants are generally of the view that the Wallumbilla GSH provides a simple and low cost platform for the commodity trading of gas. Nonetheless, the GSH is still very much in its infancy the volume of trades occurring at the hub is still developing.

As the Wallumbilla GSH hub matures, consistent with any fledging market, there will naturally be refinements to the initial market design that need to be made. This has been evidenced in both the incremental development of the STTM and DWGM since their respective market-starts.

An example of this can be seen by the desire to consolidate the current market into a single location design. As outlined above, support for the AEMO's work regarding this transition was shown by a large number of parties via submissions to this review. We consider there to be merit in complementing the technical workstream being conducted by AEMO by investigating the effects of the competitive landscape for the provision of hub services as part of Stage 2 of this review (including the possible need for economic regulation).

More broadly, we see it as prudent to consider the role of the Wallumbilla GSH as part of the wider east coast market framework in Stage 2. In particular, we will be considering how the Wallumbilla GSH can best interact with other facilitated markets going forward and potential development opportunities.

We note that AEMO is to present the options for the future design of the Wallumbilla GSH at the Energy Council meeting in mid-2015. The AEMC will be working closely with AEMO throughout the lead-up to this deliverable.

Moomba GSH

Gas at Moomba can currently be received from either the Moomba Gas Plant or SWQP and flow via the APA compound to three major pipelines (MSP, MAPS and SWQP). The close proximity of significant gas supply coupled with the option of supplying that gas to a number of demand centres is likely to make Moomba a suitable location for parties to exchange gas.

However, with one GSH already in existence (and very much in its infancy) there are understandably concerns surrounding the implications for liquidity from developing a second GSH at Moomba. This point was raised extensively in submissions with parties expressing caution regarding the development of Moomba, at least while Wallumbilla is yet to develop. Submissions stated that it would be more sensible to refine the current market design with the intention of improving liquidity at Wallumbilla, or to maybe develop a virtual hub between Wallumbilla and Moomba.

Noting this, the majority of submissions that commented on Moomba were generally supportive of its development. Many parties were of the view that any liquidity concerns were ill-founded with any detrimental effect on liquidity being difficult to predict and, at worst, likely to be short-lived so that over the longer-term both hubs will develop to be mature and liquid. It was also raised that the Moomba GSH may increase liquidity across the GSHs and support the development a forward market.

There appears to be a general consensus regarding establishing a second GSH at Moomba at some point, but parties hold divergent views as to the effect that doing so now will have on liquidity and, hence, the appropriate timing for establishing a Moomba trading location. We also note that Moomba may be being put forward by participants as a partial substitute for calls to develop greater secondary trading of capacity, as discussed in Chapter 4. We are therefore interested to hear the views of stakeholders on this proposition.

The AEMC will therefore work closely with AEMO as it develops a conceptual design of the Moomba GSH. We will then consider how and when such a design will best fit into the wider east coast framework, including an assessment of the likely effect on liquidity in the broader market. Explicit consideration will also be given to how the GSH model can more broadly interact with the other facilitated market designs on the east coast.

We note that the volume of uncontracted gas in and around Moomba may be low out to 2020.[391] We are therefore interested to hear the views of stakeholder on this and whether it has any implications for the establishment of a GSH at Moomba, particularly the volume of gas likely to be available for trade.

Later this year it is expected that MAPS will be connected to the SEA Gas pipeline.[392] We understand that, to do so, the gas flowing on MAPS will need to be odourised (consistent with that on SEA Gas pipeline) and that this differs to the other pipelines connecting at Moomba. We are therefore interested to hear participant views regarding any implications of this for the level of trading on any potential Moomba supply hub.

391 For example, Michael Fraser, the then CEO of AGL, stated at the time of releasing AGL's half year results to 31 December 2014 that "the largest volume of uncontracted gas sits with Esso-BHP in Bass Strait... when you look at the Cooper Basin [in central Australia] there is virtually no uncommitted .. reserves", see: B Robins, 'AGL warns of sustained high gas prices in NSW', Sydney Morning Herald, 11 February 2015, available at: http://www.smh.com.au/business/agl-warns-of-sustained-high-gas-prices-in-nsw-20150211-13bl9a.html#ixzz3RP8WnLDP

392 Epic Energy, Discussion Paper submission, p. 4.

8 Information Provision

Box 8.1 Summary of findings and recommendations

Gas, transportation and risk management services in the east coast gas market have historically been sold under medium- to long-term bilateral contracts. The prices and other terms and conditions struck under these agreements have invariably been treated as confidential by the parties and so too has information on some other key demand and supply fundamentals.

While some steps have been taken to reduce informational barriers, there are still some gaps and asymmetries that may be affecting the efficiency with which gas and other resources are allocated in the market and across the economy. We are therefore considering the potential for improvements to be made to:

- support the price discovery process and enable more informed and efficient decision making and risk management; and
- facilitate the development of a more liquid wholesale gas market.

The improvements that could be implemented in the next 6-12 months include:

- measures to increase the degree of transparency around wholesale gas prices (or price expectations), transportation costs and other risk management costs;
- making the Bulletin Board (BB) more of a "one-stop shop" for market participants, further improving its usability and functionality and providing market participants with greater confidence in the BB data; and
- addressing some of the clear informational gaps in the BB through the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change.

Other improvements are likely to require more fundamental changes to the reporting and/or enforcement framework. We therefore intend to examine these issues in further detail in Stage 2 of the review and, in doing so, to consider whether:

- the coverage, timeliness and accuracy of the information provided to the market can be improved and, if so, whether the benefits of any informational improvements are likely to exceed the costs; and
- broader institutional issues, including the appropriate roles for private providers and government in information provision.

The AEMC intends to work closely with AEMO when considering these issues.

8.1 Background

An important characteristic of a competitive market is that all participants have ready access to the information they require to make informed and efficient decisions about consumption, production, transportation, investment and risk management in both the short- and long-run. If this characteristic is missing from a market and decisions have to be made on the basis of incomplete, inaccurate, dated or asymmetric information, it may result in an inefficient allocation of resources (see Box 8.2).

Box 8.2 The economics of information

Markets allocate scarce resources through exchange, which creates value by allocating resources to those who value them most. Information allows more informed decision making, and greater value to be added in exchange, thereby increasing economic efficiency.

In a workably competitive market, the prices generated by the interaction of buyers and sellers can provide a useful indication of market fundamentals (eg expectations about supply and demand conditions), and a signal to efficiently allocate resources. If prices are struck in an open and transparent market then other market participants may be able to rely on the signals provided by these prices rather than having to carry out their own detailed analysis of market conditions and prices.

Markets are dynamic and participants are not always rational or able to foresee future events. This is a natural state of any market and not necessarily a market failure, and therefore not a justification for government intervention. Participants in workably competitive markets can produce solutions to informational shortages (eg through flexible contracts). However, there may be some instances where government intervention is required to improve information availability.

Information may have the characteristics of a public good – non-rivalry and non-excludability.[393] Other information may be private, which is excludable to others. This is a source of information asymmetry, the situation where a party to a transaction has greater information than the other. This can occur before or after a contract is entered into. Another source of information asymmetry is the cost of information, leading market participants to economise on, and seek efficient levels of, information.

Information asymmetry is an issue because it can lead to inefficient trade and contracting; decisions made on incorrect information can lead to price divergence and inefficient resource allocation, because parties will not have been able to take into account the actual state of the market. Information asymmetry can also arise in regulation because regulators and policy makers tend not to have as much information as the participants they are regulating.

393 Non-rivalry involves a situation where one person's consumption does not diminish another's ability to consume the good or service. Non-excludability is the prohibitively high cost of excluding a person from using or consuming a good or service.

The east coast gas market has historically operated in quite an opaque manner with gas, transportation and other risk management services sold under highly customised medium- to long-term bilateral contracts. The prices and other terms and conditions struck under these agreements have invariably been treated as confidential by the parties and so too has information on some other key demand and supply fundamentals. The lack of transparency in the market, coupled with the fact that contracts tend to be highly customised, means that the price discovery process can involve lengthy bilateral negotiations and may be afflicted by informational deficiencies and asymmetries.

Although some steps have been taken to reduce informational barriers in this market, there are still some significant informational gaps and asymmetries, which are becoming more apparent as market participants try to adjust to the changes underway in the market. There are also growing calls from market participants and the Energy Council[394] for the market to become more transparent and for improvements to be made to the coverage, accuracy and timeliness of the information made available to the market. Further detail on the factors that are driving the need for more information in the market is provided below along with an overview of the alternative roles that governments and industry can play in producing and disseminating information.

What is driving the need for more information in the market?

There are three broad factors that appear to be driving the need for further information in the east coast gas market at present.

First, the Australian economy is undergoing rapid structural change. Australia’s cost base and natural resource endowment has led to a shift away from manufacturing and gas fired electricity generation towards commodity extraction and export. In this environment, decisions are being made that will have long-term resource allocation implications. While this is a normal process for an economy, it is a particularly relevant issue now given the extent and pace of change and the uncertainty currently surrounding gas prices and the availability of supply. Uncertainty is particularly relevant at present because a large number of long-term GSAs are due to expire in the next one to two years, and decisions will be made on available information that will affect resource allocation for years to come.

Some large users have reportedly found it difficult to find producers that are willing to enter into new long-term contracts, or contracts of sufficient length to meet their commercial needs and support investment.[395] Concerns have also been raised by some users about the prices payable under new contracts.[396] There are also reports of some producers offering less flexibility in GSAs to manage variations in demand, which, given heightened uncertainty, may result in greater demand for other risk mechanisms (eg storage and the facilitated markets).

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394 COAG Energy Council Vision, December 2014, p. 4.

395 See, for example: Alliance of Industry Associations, Discussion Paper submission, 2015, p. 6. Department of Energy and Water Supply, *Gas Market Review Queensland*, 2012, p. 38 and *The Australian*, 'Clash looms as supply contracts unsecured,' 19 January 2013.

396 Alliance of Industry Associations, Discussion Paper submission, p. 6.

These changes are reportedly prompting some large users to consider whether to re-contract. While this issue is inherent in any structural change process, it appears to be exacerbated by the prevailing uncertainty in the market.

In this environment, greater information may be required to facilitate the rapid and substantial shift in resource allocation, and to enable participants to make informed and efficient long-term decisions about gas consumption, production, transportation and investment. If this does not occur, it could result in an inefficient allocation of resources.

Second, the demand for gas will soon be more concentrated than it has been in the past, with LNG producers to account for a substantial proportion of consumption. When coupled with the fact that CSG is accounting for a greater proportion of supply, the market is becoming more sensitive to changes in:

- the actions of LNG producers, both in terms of their demand for gas and their supply of gas into the domestic market; and
- technical limitations that may limit the rate at which gas production from CSG sources can be changed in response to demand fluctuations.

Short-term allocation decisions are therefore becoming a more significant issue in the market, requiring information on market changes in a more timely and accurate manner than has been provided in the past, and mechanisms to manage them efficiently. This change is also driving calls for improved information on CSG production, deliverability risks and the activities of LNG producers.

Third, the east coast gas market is evolving, with market entry, larger volumes of gas being produced and consumed, a substantial increase in the price of gas, a greater degree of short-term gas price volatility and an increasing demand from some participants for more diverse products and mechanisms to trade and transport gas and manage risk. In this environment, better quality information, more extensive coverage of information and more useful price signals are likely to be required to coordinate a larger, and more liquid and diverse market. Greater transparency is also likely to be required to support the development of new products and mechanisms to trade and transport gas and manage risk.

While these observations suggest that the market may not currently have the information required to efficiently allocate gas, regulatory intervention to require greater transparency should only occur if it can be demonstrated that there is a clear market failure. This issue is discussed in further detail below.

Institutional considerations in information provision

Given the importance of information in a well-functioning market, and the difficulties in producing and disseminating it, it is worth considering the various means of doing so. Both market- and government-based methods can be effective in improving the amount of information available to market participants and the choice between these two will depend on the extent to which there is a market failure,[397] the opportunities for entrepreneurial solutions, and the potential for unintended consequences from government intervention.

397 The term "market failure" is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

Government intervention may occur where there are informational deficiencies or asymmetries that cannot be corrected by the market. This may be due to market power, limited commercial incentive to make available sensitive information, or the cost involved. Government intervention may take a number of different forms. For example, market participants may be required by a legislative instrument to provide certain information to the market, government may provide the information itself, or it may establish a mechanism to improve information provision. Like any market failure, government intervention should only occur if the benefits of the intervention are likely to outweigh the costs.

Private organisations can also play a role in providing information to the market, or even requiring information to be provided to the market (eg the ASX requires continuous disclosure of market sensitive information as a necessary condition for an exchange listing). Examples of private providers of information in the east coast gas market include EnergyQuest's EnergyQuarterly and the Argus LNG Daily market report.

Other recent developments in private information provision have involved platforms that match buyers and sellers of certain products. This business model involves the use of a platform to bring together market participants and information, and in so doing reducing transaction costs and enabling previously uneconomic trades to occur.[398] The platform operator receives a portion of the value created in the trade. Examples of these types of platform businesses include eBay, Uber and airbnb.

As this brief discussion highlights, there are various ways in which relevant and useful information can be brought into a market for use by participants. When considering the role that government should play with respect to information provision in the east coast gas market, key considerations include:

- the potential role for the private sector in providing information; and
- whether the government may need to require the private sector to provide information, and any role for government in verification and enforcement.

Finally, in considering the role of government, it is also necessary to consider the level or coverage of information that the government may wish to provide or require. While it may seem apparent that more information should be preferred to less, this may not always be the case. Careful consideration must therefore be given to the level of information required by the market.

398 In bringing together both sides to a trade that were previously not connected, information on willingness to buy and sell is revealed and trade is enabled. Information is also generated by requirements imposed by the market operator, such as information provision as a condition for entering the market, and feedback as to the performance of both parties to the contract. Therefore, screening and reputation overcomes information problems associated with pre- and post-contract behaviour, thereby enabling trust and further trade to occur. Therefore, platforms may substantially reduce information problems.

Matters considered in the chapter

Given the matters outlined above, it is relevant to consider whether improvements can be made to the coverage, timeliness and accuracy of market-based information to:

- simplify the price discovery process and enable more informed and efficient decision making and risk management to occur; and
- facilitate the development of a more liquid wholesale gas market, an efficient reference price and risk management products over the longer term.

These matters are explored in further detail in this chapter, which is structured as follows:

- section 8.2 sets out the information currently available to market participants, the observations that stakeholders and recent reviews have made about this information and the steps that have recently been taken to try and improve the National Gas Bulletin Board (BB); and
- section 8.3 considers whether further improvements can be made to the current arrangements to improve the efficiency with which decisions are made.

8.2 Information currently available in the market

A number of steps have been taken by policy makers and market participants over the last ten years to increase the level of transparency in the east coast gas market and enable more informed decisions to be made about the consumption, production and transportation of gas and longer-term investments.[399] Notwithstanding the developments that have occurred in this area, concerns have been raised by a number of parties about:

- the lack of transparency surrounding wholesale gas prices, transportation costs and other risk management services; and
- the fragmented and incomplete nature of the information currently available to the market.

Similar concerns were also expressed in the Energy Council's Vision, which noted the need for more accurate and transparent market-making information on pipeline and large storage facilities operations and capacity, upstream resources, and the actions of producers, export facilities, large consumers and traders.[400]

Further detail on the concerns that have been raised is provided below, along with a brief overview of the information currently available to market participants.

399 These steps include, amongst others, the development of the National Gas Bulletin Board in mid-2008, the introduction of the Gas Statement of Opportunities in 2009 and the introduction of capacity listing services by some pipeline owners.

400 COAG Energy Council Vision, December 2014, p. 4.

8.2.1 Existing informational resources

The resources that market participants can currently have recourse to when making consumption, production, transportation, risk management and investment decisions include:

- The National Gas Services Bulletin Board (BB), which is administered by AEMO and contains information on the standing capacity, short- and medium-term capacity outlook and utilisation of designated production facilities, storage facilities and transmission pipelines in eastern Australia. It also contains a listing service for transmission capacity and gas (see Box 8.3 for further detail on the BB).
- The Gas Statement of Opportunities (GSOO) and National Gas Forecasting Report, which are prepared by AEMO on an annual basis and contain consumption forecasts, reserve estimates, production and transmission cost estimates, storage, processing and transmission information and a supply adequacy assessment.
- AEMO's website, which contains pricing and other market based information from the Wallumbilla Supply Hub, the DWGM and STTM.
- The AER's publications, which include:
  - a Weekly Gas Market Report, which contains information on activity in the Wallumbilla Supply Hub, DWGM and STTM, production and pipeline flows and gas fired generation; and
  - regulatory decisions for pipelines that are subject to full regulation.
- State and Commonwealth government reports on gas resources and major projects (eg the Commonwealth Department of Industry and Science publishes Resources and Energy Quarterly, Resources and Energy Statistics, and Australian Energy Projections).[401]
- Industry publications, such as EnergyQuest's EnergyQuarterly, which contains information on exploration, production, consumption, wholesale gas prices, the LNG projects, gas fired generation, storage and transmission pipelines.
- Market participants' websites (eg producers' and pipeline owners' websites and the capacity trading websites that have been set up by APA and Jemena).
- Annual reports and other periodic disclosures for ASX-listed entities (eg disclosure of price-sensitive information and periodic disclosure of production, development and exploration activities for mining, oil and gas producing entities).
- Information that is discovered or revealed during bilateral contract negotiations.

The coverage of these informational sources is highlighted in Figure 8.1 .

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401 A list of the Department of Industry and Science's publications can be found here: http://www.industry.gov.au/industry/Office-of-the-Chief-Economist/Publications/Pages/default.aspx#

Box 8.3 Bulletin Board

The BB was established in July 2008 following a recommendation by the Gas Market Leaders Group (GMLG) that a web-based electronic communications system be developed to provide market participants and observers (including governments) with ready access to up-to-date information on the demand-supply outlook for key production facilities, storage facilities and transmission pipelines in eastern Australia.[402]

The regulatory arrangements applying to the BB are set out in Chapter 7 of the NGL and Part 18 of the NGR. Unlike the access regulation provisions, which only apply to covered pipelines, these provisions apply to a broader group of transmission pipelines, production and storage facilities in eastern Australia.

The BB provisions in the NGL and NGR require AEMO to operate and maintain the BB and notify the AER of any breaches of this part of the NGR. They also allow AEMO to:

- develop procedures that, among other things, specify the way information is to be provided, published and maintained on the BB and to define demand and production zones; and
- declare that a transmission pipeline, gas storage facility or production facility become a BB facility if it is not subject to an exemption declaration.

If a pipeline, storage or production facility is declared a BB facility, it is required by **rules 163-174** of the NGR to provide AEMO with information on, amongst other things, the standing capacity of the facility, the facility's short-term (7-day) and medium-term (12 month) capacity outlook and the daily utilisation of the facility. BB pipelines are also required to provide aggregated information on pipeline nominations and forecast deliveries by zone and a 3-day linepack capacity adequacy outlook flag. Further detail on the information BB facility operators are required to provide AEMO under the NGR is set out in Figure 8.1.

The BB provisions also allow registered participants to notify other users if they have gas or spare capacity to sell.

The costs that AEMO incurs in operating and maintaining the BB are recovered from shippers that utilise the BB pipelines through a fee that reflects the shipper's share of the volume of gas transported in the relevant period (**rule 191**).

402 Gas Market Leaders Group, *National Gas Market Development Plan*, June 2006, p. 4.

Figure 8.1 Information coverage

	Upstream			Transmission Pipelines			Distribution	Storage Facilities		STTM and DWGM	Demand
	Resources and Reserves	**Production** (capacity, production, outlook)	**Wholesale Gas Prices**	**Pipeline** (capacity, utilisation, outlook)	**Secondary capacity**	**Transport Costs**	**Transport Costs**	**Storage** (capacity, utilisation, outlook)	**Storage costs**	**Prices, injection and withdrawal**	**Current and outlook**
Bulletin Board	×	BB facilities only	×	BB facilities only	Listing service	×	×	BB facilities only	×	×	×
GSOO	✓		×	✓	×	Estimates for some pipelines	×	✓	×	×	Historic and forecast
AEMO's website/trading platforms	×	×	Wallumbilla Gas Supply Hub information	×	×	×	×	×	×	✓	×
AER reports	×	×		×	×	For regulated pipelines	For regulated pipelines	×	×	✓	×
Government reports	✓	×	×	×	×	×	×	×	×	×	Historic estimates
EnergyQuest	✓		Estimates	✓	×	Estimates for some pipelines	×	✓	×	×	Historic estimates
Market participants' websites	Some producers' websites		×	Some pipeline owners' websites	APA's and Jemena's capacity trading websites	Some pipeline owners' websites	✓	Some websites	×	×	×
Annual reports and other public announcements	Some producers' annual reports and production and reserves reports		Media releases (if ASX listing)	×	×	×	×	✓	×	×	×

8.2.2 Observations from previous reviews

A number of the reviews carried out in the last two years identified shortcomings with information provision in the east coast gas market and made some recommendations on how these shortcomings could be addressed.

For example, in the Scoping Study consultation process, concerns were raised by a number of stakeholders about:[403]

- the level of information available on the BB;
- the fact that some storage facilities in Queensland were not BB facilities;
- the quality and accessibility of the existing STTM, DWGM and BB data; and
- the lack of transparency surrounding transportation costs on some pipelines.

The Eastern Australian Domestic Gas Market Study also expressed concerns about the adequacy of the information available to the market to support the price discovery process and enable informed decisions to be made, and the following matters:[404]

- the lack of transparency surrounding wholesale gas prices, which the study noted may render some participants unable to negotiate confidently on price and could also hinder the development of forward markets and risk management products;
- the availability of information on CSG developments and delivery risks;
- the limited information on processing and storage capacity, utilisation of transmission pipelines, capacity trading activity and transmission costs; and
- the quality of information available for planning and investment decisions.

To address these concerns, the study recommended that further reform be carried out in this area, in consultation with industry, and focus on “improving price discovery in the wholesale market, including mechanisms to provide increased visibility on key market drivers."[405] The study also recommended specific improvements to the BB and GSOO and encouraged industry to progress the development of a gas price index.[406]

Similar recommendations were also made by the Victorian Gas Market Taskforce, who noted that the level and quality of information in the market could be improved by:[407]

- accelerating industry-led efforts to develop a survey based forward gas price index to report price expectations;
- publishing available transmission capacity on the BB; and

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403 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 128.

404 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, pp. 15-16, 64 and 90.

405 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 89.

406 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 90.

407 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 90.

- including a comprehensive annual forecast of reserves, gas supply, industrial and residential demand and supply and transportation asset capacity in the GSOO.

8.2.3 Stakeholder submissions

The submissions on information provision primarily focused on the adequacy of existing information and where improvements could be made. Some stakeholders also commented on emergency arrangements currently in place. An overview of the views expressed by stakeholders on these issues is provided below.

Adequacy of existing information

A common theme emerging from most of the submissions to the Discussion Paper is that there is insufficient information in the market at present to enable participants to make informed and timely decision on consumption, production, transportation, investment and risk management, and that change is required. This view can be seen clearly in the following statement from GDF Suez Australian Energy (GDFSAE):[408]

> "Presently, information arrangements are fragmented across multiple platforms and are incomplete which creates concerns for market participants, especially those not across the breath of the supply chain, and interested stakeholders. The rapid development of liquefied natural gas facilities has also heightened the sense that market information is insufficient or incomplete.
>
> Information is critical to enable participants to make decisions on how to respond to and manage risk. In this regard, as information asymmetries are genuine impediments to fully functioning markets GDFSAE has some support for the view that the market would be better served by more centralised and complete reporting arrangements."

GDFSAE's views on the current state of information and why further information is required were echoed by:

- the Group of Leading Energy Companies and Major Users (GLECMU), who claimed that there is inadequate information in the market at present for participants to respond to and manage risk and that improvements in the availability and transparency of information are required to facilitate trade, liquidity and to provide clear price signals;[409]
- Stanwell, who claimed the BB is difficult to use and has incomplete information;[410]
- QGC, who stated that information is critical to facilitating an effective and liquid market and that capacity trading arrangements and "within-day" pricing cannot be implemented without "meaningful market information to support trade;"[411]

408 GDFSAE, Discussion Paper submission, p. 4.

409 GLECMU, Discussion Paper submission, p. 2.

410 Stanwell, Discussion Paper submission, p. 7.

411 QGC, Discussion Paper submission, p. 6.

- ERM Power, who noted the importance of having an appropriate level of information on the BB to help participants make informed trading and investment decisions and manage their commercial gas portfolios.[412]

A number of stakeholders[413] also called for improvements to be made to the BB, although some noted that careful consideration would need to be given to the cost of imposing new obligations on parties and confidentiality issues.[414] Some of the more significant improvements that stakeholders suggested could be made to the coverage, timeliness, accuracy and transparency of information in the market are outlined below, while Figure 8.2 sets out some of the specific improvements stakeholders suggested should be made to the BB:

- *Coverage:* GDFSAE, the GLECMU[415]and Arrow Energy[416] suggested a more centralised and complete reporting framework be developed and encompass both supply and demand. Arrow Energy also suggested a scoping study be carried out to identify what information was required and the most efficient means of meeting those requirements.[417] QGC also suggested a scoping study be carried out and that going forward greater emphasis be placed on information relevant to trading and managing commercial positions than on infrastructure reporting.[418] A number of stakeholders[419] also suggested the coverage of the BB be expanded to include information on the LNG producers' activities and noted that without this information other participants in the market could be exposed to more risk and be placed at competitive disadvantage in other markets (eg the NEM).[420]
- *Timeliness:* Stanwell[421] raised some concerns about the timeliness with which information is published on the BB, while QGC[422] and APLNG[423] suggested that some information start to be published on a real-time basis (eg pipeline flows).
- *Accuracy:* Stanwell also raised concerns about the accuracy of the information published on the BB and the fact that there is "no penalty or incentive for participants to meet deadlines and for the relevant bodies to enforce the rules."[424]

412 ERM Power, Discussion Paper submission, p. 11.

413 APLNG, Discussion Paper submission, p. 1, Arrow Energy, Discussion Paper submission, p. 5, EnergyAustralia, Discussion Paper submission, p. 4 and ESAA, Discussion Paper submission, p. 10.

414 See, for example: ESAA, Discussion Paper submission, p. 10 and GLECMU, Discussion Paper submission, p. 2.

415 GLECMU, Discussion Paper submission, p. 2.

416 Arrow Energy, Discussion Paper submission, p. 5.

417 Arrow Energy, Discussion Paper submission, p. 5.

418 QGC, Discussion Paper submission, p. 7.

419 ERM Power, Discussion Paper submission, p. 11, Alinta, Discussion Paper submission, p. 3 and AER, Discussion Paper submission, p. 3

420 In its submission, Alinta stated that there is a "compelling argument" for LNG proponents to be subject to a similar compulsory reporting obligation to that applied to generators in the NEM, given information on the timing and volume of ramp gas can affect gas and electricity prices. Alinta, Discussion Paper submission, p. 3.

421 Stanwell, Discussion Paper submission, p. 7.

422 QGC, Discussion Paper submission, p. 6.

423 APLNG, Discussion Paper submission, p. 1.

- *Transparency:* Both GDFSAE and Alinta are of the view that the level of transparency in the gas market should be at least equivalent to the National Electricity Market (NEM) and "in the spirit of disclosure obligations for the Australian Stock Exchange."[425] Stanwell also suggested that consideration be given to whether greater consistency with the NEM information processes could be achieved.[426]

Figure 8.2 Suggested improvements to the BB

<table>
<tr><th colspan="2">Suggestion</th><th>Proponent</th></tr>
<tr><td colspan="3">Pipeline Information and Information to Support Capacity Trading</td></tr>
<tr><td colspan="2">Real time or on the day information on gas flows</td><td>APLNG, QGC, GDFSAE, AEMO</td></tr>
<tr><td colspan="2">Information on linepack and injections and withdrawals</td><td>GDFSAE</td></tr>
<tr><td rowspan="2">Capacity availability</td><td>Contracted capacity</td><td>GDFSAE</td></tr>
<tr><td>Uncontracted capacity or availability of firm primary capacity for the month ahead and 12mth forecast.</td><td>APA and APGA</td></tr>
<tr><td rowspan="2">Pipeline utilisation information</td><td>Utilisation rates</td><td>APLNG and Lumo</td></tr>
<tr><td>Analysis of historical flows to provide users with a reasonable basis to assess anticipated utilisation.</td><td>APGA</td></tr>
<tr><td colspan="2">Information on pipeline constraints</td><td>APLNG</td></tr>
<tr><td colspan="2">Graphical representation of historic daily flows against capacity</td><td>APGA</td></tr>
<tr><td colspan="2">Forecast and current amount of pipeline capacity available for storage</td><td>Stanwell</td></tr>
<tr><td colspan="2">Contact details of each shipper on the pipeline to reduce search costs.</td><td>APGA and APA</td></tr>
<tr><td colspan="3">Storage</td></tr>
<tr><td colspan="2">Amount of gas available in storage facilitates</td><td>Stanwell, AEMO</td></tr>
<tr><td colspan="3">Demand</td></tr>
<tr><td colspan="2">New LNG/Gladstone demand zone to capture pipeline flows, capacity outlook and outage information related to these facilities</td><td>ERM, AER and Alinta</td></tr>
<tr><td colspan="2">Comprehensive gas demand data</td><td>GDFSAE, Arrow, GLECMU</td></tr>
<tr><td colspan="3">Listing service</td></tr>
<tr><td colspan="2">Listing service for gas</td><td>Qenos</td></tr>
<tr><td colspan="2">Listing service for storage</td><td>APLNG</td></tr>
<tr><td colspan="3">All facilities</td></tr>
<tr><td colspan="2">Improve the information that BB facilities have to provide on the medium term capacity outlook</td><td>Stanwell and Alinta</td></tr>
<tr><td colspan="3">Other</td></tr>
<tr><td colspan="2">A net system load profile for each hub or network area</td><td>Stanwell</td></tr>
<tr><td colspan="2">Publication of STTM, DWGM and WSH data on the BB</td><td>Qenos</td></tr>
<tr><td colspan="2">Information on transportation costs</td><td>Scoping Study and Eastern Australian Gas Market Study</td></tr>
</table>

424 Stanwell, Discussion Paper submission, p. 7.

425 GDFSAE, Discussion Paper submission, p.4 and Alinta, Discussion Paper submission, p. 3.

426 Stanwell, Discussion Paper submission, p. 7.

AEMO agreed with the sentiments expressed by most stakeholders, but noted that its ability to amend the BB was constrained somewhat by the provisions in the NGR:[427]

> "The BB's current regulatory framework is rigid and has not evolved alongside an increasingly complex gas network. Without sufficient information about storage or any large user information, the current information is incomplete. The GBB has the potential to further complement gas markets by providing more relevant and dynamic information (such as real-time data) and information about storage to better inform trading positions."

Emergency arrangements

In its submission to the Discussion Paper, Alinta noted that gas emergency management and shortage issues are currently managed in a "disparate fashion and at a jurisdictional level." Alinta therefore suggested that further consideration be given to whether a coordinated approach can be adopted that allows jurisdictions to retain control but allows AEMO to act as the agent in charge of managing technical issues.[428]

This issue was also touched on during the Scoping Study, with a number of stakeholders noting the need for greater transparency around the curtailment principles to be employed in an emergency and a more comprehensive set of information to be made available during emergencies.[429]

8.2.4 Recent informational improvements and changes underway

Over the last 18 months a number of steps have been taken to:

- Improve the functionality and usability of the BB: AEMO commenced work on this project in 2014 and the first phase of the redevelopment, which included redesigning the BB interface and developing a capacity listing service, was completed in late 2014.[430]
- Improve the quality of some of the information reported on the BB: Over the last year the AER has worked with CSG producers to improve the quality of the information they provide to the BB.[431]
- Address some of the informational gaps on the BB: In May 2014, the AEMC made a rule to amend the NGR to increase the level of short- and medium-term capacity outlook information to be published on the BB.[432] The AEMC also recently made

427 AEMO, Discussion Paper submission, p. 2.

428 Alinta Energy, Discussion Paper submission, pp. 8-9.

429 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 101.

430 AEMO, *Gas Bulletin Board Draft Budget: 2015-16*, March 2015. The second phase of the re-development is expected to involve improving the upload and validation functionality while the third phase is expected to involve incorporating any new data arising from the rule change.

431 AER, Discussion Paper submission, p. 3.

432 AEMC, *Final Rule Determination – National Gas Amendment (National Gas Bulletin Board Capacity Outlooks) Rule 2014*, 1 May 2014.

a rule to remove the requirement in the NGR for an emergency information page on the BB.[433]

- Improve the quality of planning and investment related information: In 2014 AEMO published its first National Gas Forecasting Report and has also made a number of improvements to the GSOO.

The Energy Council has also undertaken a significant amount of work to determine what information is likely to be required to facilitate a greater degree of capacity trading amongst shippers and has recently submitted the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change to the AEMC. As the following statement from the Energy Council highlights, the scope of the proposed rule change extends beyond just facilitating secondary capacity trading:[434]

> "In preparing this proposal, officials have also identified other rule changes relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of AEMO's *Gas Statement of Opportunities* (GSOO); and enable a more accurate understanding of gas flows in Australia's east coast gas market and in turn allow a better representation of gas flows to be published on the BB."

The additional information that BB facility operators would be required to provide under the rule change is set out in the shaded cells in Figure 8.3.

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433 AEMC, *National Gas Amendment (Removal of Gas Bulletin Board emergency information page) Rule 2015*, 23 April 2015.

434 COAG Energy Council, *National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information*, 30 March 2015, p. 3.

Figure 8.3 Existing and proposed information provision for the BB

Information to be provided to AEMO		Frequency
	BB Transmission Pipeline Operators	
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium term capacity outlook (utilising maintenance reports provided by facility operators to shippers)	As issued
	Actual pipeline gas delivery information for each demand and production zone for the previous day.	Daily
	Aggregated delivery nominations by zone and aggregated forecast deliveries by zone for subsequent gas days.	Daily
	3-day linepack capacity adequacy outlook flag	Daily
	Contact details	Daily
Uncontracted capacity	3-year outlook for uncontracted (available) primary capacity	Monthly
	List of shippers with contracts and contact details in the relative order of their contracted capacity	Monthly
Secondary capacity trade	Data from secondary capacity trading platforms	Week-after basis
Detailed facility data	Location of receipt and delivery points, production, storage and transmission pipelines to the pipeline connects, name plate rating for each gate station and delivery points that constitute gate stations	As applicable
Flow data by point	Aggregated receipt / delivery point flow data by zone	Day after basis
	Disaggregated receipt/delivery point flow data (confidential)	Monthly
	BB Storage Provider	
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium term capacity outlook (utilising maintenance reports provided by facility operators to shippers)	As issued
	Actual production data for each gas day.	Daily
	Contact details	Daily
Detailed facility data	Identification of all of the BB pipeline, receipt and delivery points connected to the storage facility	As applicable
	BB Production Facility Operators	
Existing information requirements	Name plate capacity rating	Annual*
	7-day capacity outlook (short-term)	Daily
	Medium term capacity outlook (utilising maintenance reports provided by facility operators to shippers)	As issued
	Actual storage data for each gas day.	Daily
	Contact details	Daily
Detailed facility data	Identification of all of the BB pipelines, receipt and delivery points connected to the production facility.	As applicable

*If the capacity rating changes, the facility operator must notify AEMO as soon as practicable.

Note: shaded areas indicate information proposed in the rule change request.

A further development that is currently being considered by AEMO is whether the BB procedures should be amended to include a new demand zone at Curtis Island. If this change is made to the procedures it will result in:

- QCLNG, GLNG and APLNG pipelines and any production or storage facilities that inject gas directly or indirectly into these pipelines becoming BB facilities; and
- each facility being required to provide the information specified in the NGR once GLNG's project commences in late-2015.

The ACCC's inquiry into the competitiveness of wholesale gas prices and the structure of processing, transportation, storage and marketing segments of the gas industry, announced on 5 April 2015, will examine information transparency and transaction costs, including gas supply contractual terms and conditions.[435]

As this brief summary highlights, a number of the improvements that have been suggested in earlier reviews and by stakeholders have already been addressed, or are in the process of being considered either as part of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change or AEMO's BB procedure change.[436] There are, however, a number of suggested improvements that have not yet been addressed, such as:

- increasing the level of transparency around wholesale gas prices, transportation costs and other risk management services;
- reducing the degree of information fragmentation, continuing to improve the usability and functionality of the BB and improving the accuracy, timeliness and general compliance of the information provided by BB facilities;
- including more detailed information on storage and the medium-term capacity outlook on the BB;
- expanding the coverage of the BB to include large end-users and other more fundamental changes to the reporting and enforcement framework; and
- improving the emergency arrangements.

These suggestions are considered in further detail below.

8.3 AEMC's Stage 1 findings

Like the Energy Council and the majority of stakeholders, the AEMC is of the view that additional measures are required to increase the level of transparency in the market, support the price discovery process and enable more informed and efficient decision making and risk management to occur. Over the longer-term, these measures should also facilitate the development of a more liquid wholesale gas market, an efficient reference price and risk management products.

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435 Australian Government, *Inquiry into competitiveness of the Wholesale Gas Industry*, Terms of Reference, 8 April 2015.

436 For example, the ERM Power, Alinta and AER suggestion that information on the LNG producers' activities be reflected on the BB.

The measures the AEMC is currently considering can be divided between those that:

- can be implemented in the next 6-12 months because they do not require changes to the existing reporting framework, or can be considered as part of the Enhanced Information rule change;
- will need to be considered more closely in Stage 2 because they require more fundamental changes to the reporting and enforcement framework; and
- could be examined in Stage 2, but may also be considered further by the Commonwealth, state and territory governments (ie the emergency arrangements).

Further detail on these measures is provided below. Before moving on, it is worth noting that the Commission is aware that information provision is not costless and that there are genuine reasons for some information to remain confidential. We are also aware that any additional reporting obligations should be targeted, fit for purpose and proportionate to the issue it is intended to address.

8.3.1 More immediate actions

Some of the more immediate information-related measures that we are currently considering are designed to:

- improve the degree of transparency around wholesale gas prices (or price expectations), transportation costs and the price of other risk management services;
- make the BB more of a "one-stop shop" for market participants; and
- address some of the more obvious informational gaps in the BB through the Enhanced Information rule change.

Each measure is discussed, in turn, below.

Improving transparency

As noted in the introduction to this chapter, gas in the east coast market has historically been sold under medium- to long-term, highly customised bilateral contracts. While the prices struck within these contracts have invariably been treated as confidential, there are some information sources that market participants can have recourse to, including:

- ASX announcements and company reports; and
- industry publications, such as EnergyQuarterly, which contain estimates of gas prices realised by producers and anecdotal reports of the new contract prices.

Market participants can now also have recourse to the prices emerging from the Wallumbilla GSH when considering the short-term value of gas, although as noted in Chapter 7 this market is still in its infancy and the volume of trades is currently quite low, so it does not currently constitute an efficient reference price. While there is some information on wholesale gas prices in the market, greater transparency may be required as a transitional measure until there is an efficient reference price that market participants can have recourse to. To this end, we are giving consideration as to how this could be achieved.

One option that has been suggested by some stakeholders is to require contracting parties to reveal the prices they are required to pay under their GSAs. While such an action would increase transparency, it is unclear how much value the market would derive from this information given the prices payable under these contracts reflect the totality of all the terms and conditions of supply and not just the value of a unit of gas.[437] Requiring market participants to divulge this information could also undermine confidence in the market (eg through the potential for tacit collusion, or the potential effects on risk management practices) and have adverse consequences for competition in some downstream markets.[438] In general, there is potential for unintended consequences from information provision, necessitating close consideration before any requirements are made. While we are therefore cautious of exploring this option further, we would welcome stakeholders' views on its costs and benefits.

There are two other options that we would be interested in receiving feedback from stakeholders on, as follows:

- Developing a survey-based gas price index that would reflect market participants' price expectations for short, medium and longer-term contracts with basic terms and conditions[439] and supply from the major delivery points (ie Wallumbilla, Moomba, Longford, Port Campbell and Yolla). This option has been canvassed in a number of earlier reviews[440] but does not appear to have gained traction. We would therefore like to get a better understanding of whether market participants think there would be value in this option and, if so, what the impediments to its development may be, how it could be conducted and who should be responsible for conducting it.
- Aggregating existing publicly available information and anecdotal reports on gas prices into a monthly, quarterly or bi-annual report and publishing this on the BB. Such a report could form part of an existing report (eg the GSOO, the AER's State of the Energy Market or the AER's Weekly Gas Market Report) or be developed as a separate stand-alone report. Again, we would be interested in obtaining stakeholders' views on the value of such a report to market participants and policy makers, and who would be best placed to prepare such a report.

437 For example, the price struck under a GSA will depend on, among other things: (a) the minimum proportion of contract quantities the buyer must pay for in a year (the take or pay commitments); (b) the load factor (ie the buyer's ability to take more than the average daily quantity in the year); (c) the ability of the buy to adjust its contract quantities over the contract terms; (d) the price escalation mechanism, which may be linked to inflation or the price of other fuels; and (e) how often the price can be review and the nature of the price review.

438 For example, if gas fired generators were required to reveal the costs and other terms and conditions of supply then it could place them at a competitive disadvantage relative to other participants in the market.

439 For example, the contracts could be assumed to provide for the firm supply of gas, have a 100 per cent take or pay provision, a 100 per cent load factor, no make-up gas provisions and no ability to vary contract quantities, a CPI price escalation mechanism and no price review clause.

440 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 90, and Victorian Government *Gas Market Taskforce*, Final Report and Recommendations, October 2013, p. 8.

We are also open to other suggestions that stakeholders may have about achieving greater transparency in this area.

While the greatest source of concern at present appears to be the lack of transparency surrounding wholesale gas prices, concerns have also been raised in the past about the lack of transparency surrounding the prices payable on some pipelines and the prices payable for storage services.[441] One option for dealing with this issue could be to make provision on the BB for pipeline operators and storage providers to publish their tariffs for available capacity and encourage them to use that service. If this information is not forthcoming, consideration could be given to whether the NGR could be amended to require all BB pipelines and storage providers to provide this information. Once again, we are interested in hearing stakeholders' views on how transparency in this area could be improved and if there are any other market-led initiatives that could be employed.

Making the BB a "one-stop shop"

As Figure 8.1 highlights, the informational sources in the east coast gas market are quite fragmented at present. There could therefore be value in the BB becoming more of a "one-stop shop" for market-based information. We are therefore considering changes that could be made to the BB within the confines of the existing reporting framework to make it a more comprehensive source of information, further improve its usability and functionality and improve the reliability of the information provided.

Our preliminary views on the changes that could be made to the BB to increase its scope and improve its usability and functionality are outlined in Table 8.1. There may, of course, be other relatively simple improvements that can be made to the BB that would not require a rule change and we would welcome hearing stakeholders' views on this before we suggest that further work be carried out in this area.

441 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p128 and Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, 2014, p. 100.

Table 8.1 Improvements to the BB

Improvement	Detail
Include information on prices from the facilitated markets	Develop a new facilitated markets pricing page that includes: • current and historic information on prices and other relevant information from the Gas Supply Hub, STTM and DWGM • the AER's Weekly Gas Market Report.
Include planning and longer term forecasts information	Develop a new long-term forecast and planning page that includes the GSOO, the National Gas Forecasting Report and associated material.
Expand the scope of capacity listing	Expand the scope of the capacity listing page to include a separate listing service for gas, transportation and storage capacity.[442]
	Consider, in consultation with APA and JGN, the extent to which bids and offers on their respective capacity trading sites could also be published on the BB so that prospective shippers can find this information on a single website.
	Reconsider whether market participants should be required by the BB procedures to list available gas or spare capacity through the GSH, given the financial and logistical hurdles this may present.
Allow transportation and storage charges to be published	Consider developing a section on the BB that can be used by pipeline operators and storage operators to post their transportation and storage charges.
Further improvements to the BB's layout and functionality	Continue to improve the usability and functionality of the BB by, for example: • making key information easier to find on the home page;[443] • developing separate pages for production, transmission and storage, which would include the information BB facilities are required to provide AEMO; • providing greater clarity about what some of the data represents;[444] • making greater use of some of the information provided by BB facilities[445] and improving the website's charting capability;[446] and • establishing a new section for the BB procedures and the AER's compliance reports.

If the BB is to become a one-stop shop then market participants will also need to have greater confidence in the accuracy and timeliness of the information that BB facilities

442 Rule 176 currently allows BB participants to notify other BB users if they have "spare capacity." The term "spare capacity" is not a defined term in the NGR, so it is possible that this term could be interpreted as spare transportation, storage or processing capacity.

443 The Western Australian Gas Bulletin Board and the National Grid's Prevailing View site are useful examples that could be drawn on when considering this issue.

444 For example, it is unclear at present whether daily production data includes or excludes gas that is put into storage.

445 For example, the information on actual flows and standing capacities could be used to calculate an historic utilisation rate to help shippers that are considering access to a pipeline.

446 For example, the actual flow data charting capability could include information on standing capacities as well as actual flows.

are providing than they currently do. There would therefore be value in the AER continuing to work with AEMO to streamline the process for monitoring and enforcing compliance, to identify and address areas of systemic non-compliance in a timely manner. This might include conducting audits, where necessary, of information provided in the last 6-12 months and working with BB facility operators to address any non-compliance issues.

Other informational gaps that could be addressed in the upcoming rule change

While the starting point for the AEMC's assessment of the Gas Transmission Pipeline Capacity Trading: Enhanced Information rule change will be the Energy Council's rule change proposal (see Figure 8.3), we also intend to consider whether there are any other informational gaps that fall within the scope of the proposed rule change[447] that could also be dealt with at this time.

Some of the matters that have been raised by stakeholders and earlier reviews that could potentially fall within the scope of this rule change, include the suggestions that:

- all storage facilities connected to BB pipelines be deemed BB facilities even if they just form part of a production facility;[448]
- BB storage facilities be required to provide information on the total volume of gas stored in the facility each gas day;[449]
- BB pipelines be required to provide more information on linepack (eg beginning of the day linepack and forecast linepack for the following two days) and nominations by both receipt points and delivery zones; and
- further improvements be made to the medium-term capacity outlook information that BB facilities are required to provide AEMO (eg provide a rolling 12 month capacity outlook; standardising the format the information is provided in; and requiring the information to be updated on a regular basis).[450]

Whether or not these suggestions would satisfy the NGO is something that would need to be carefully considered as part of the rule change process.

447 The scope of the rule change has been described by the Energy Council as rules "relating to the provision of gas pipeline flow and facility data that will: improve the operational management of facilitated wholesale gas markets; better inform the development of the GSOO; and enable a more accurate understanding of gas flows in Australia's east coast gas market and in turn allow a better representation of gas flows to be published on the BB". COAG Energy Council, National Gas Rule Change Request and Proposal – Gas Transmission Pipeline Capacity Trading: Enhanced Information, 30 March 2015, p. 3.

448 Implementing this change would require the nameplate and production facility exemption provisions in rule 150(5) to be removed.

449 Implementing this change would require rule 169 to be amended.

450 Implementing this change would require amendments to rules 165, 168 and 171.

8.3.2 Stage 2 opportunities

Stage 2 of the East Coast Review will provide an opportunity to consider more closely the fundamental role of information in enabling efficient decision making and risk management to occur and facilitating the development of a more liquid wholesale gas market, an efficient reference price for gas and risk management products over the longer term. It will also enable a more detailed consideration of the following questions to be carried out, having regard to changes in market design that may alter the role and nature of information required by the market:

- Coverage: What specific information across the supply chain is required to facilitate the development of a more informed market? Should the coverage of the BB extend to large users as it does in Western Australia? Is information on exploration and reserves required on the BB?
- Timeliness: Given the dynamism and information-intensity of the market, is more timely information now required? In what areas is more timely information required? How important is real-time information as opposed to on the day information? Is something approaching the continuous disclosure requirement in the ASX required?
- Accuracy: How could the accuracy of information provided by BB facilities be improved? Are more effective enforcement mechanisms required to encourage BB facilities to provide accurate and timely information? Should the information that BB facilities provide be subject to a specific standard (eg a "best estimates arrived at on a reasonable basis" test)? Is the presence of civil penalty provisions in the NGL effective in encouraging compliance, and is there a need to expand the coverage of these provisions?
- Cost of information: What is the best way of collecting, organising and disseminating information at least cost? How should costs be allocated among market participants?

Stage 2 of the review will also examine more closely the key questions relating to information provision, such as who should be responsible for providing it, how it should be provided and to whom, to what extent does information provision need to be mandated and what role can the market and private providers play. Stakeholders' views are welcomed on these questions.

Given AEMO's extensive technical and market-based experience, the AEMC intends to work closely with it when considering each of these issues.

8.3.3 Emergency arrangements

The final matter that has been raised in submissions that, in the AEMC's view, warrants further consideration are the arrangements that have been put in place to deal with emergencies extending beyond one jurisdiction. These arrangements are currently set out in the National Gas Emergency Response Protocol Memorandum of Understanding (Protocol).[451] In short, the Protocol:

- recognises that commercial arrangements should be allowed to operate, as far as possible, to address any shortfall in supply and maintain system security, and that the exercise of a jurisdiction's emergency powers should only occur as a last resort;
- provides for the establishment of the National Gas Emergency Response Advisory Committee (NGERAC) and sets out the functions and roles it is to play;
- specifies the principles that should guide the Energy Council and jurisdictions when considering the advice of NGERAC and any potential use of jurisdictional emergency powers; and
- sets out the consultation that should occur between affected jurisdictions.

Stakeholders in the Scoping Study also raised some concerns about these arrangements. The study suggested that these comments be passed onto the then Commonwealth Department of Industry along with their high level observations on the need to:

- improve the transparency and accessibility of the arrangements and provide greater clarity about the following matters by either updating the Protocol, or moving the emergency arrangements into the NGL and NGR:
  - the role to be played by AEMO during an emergency;
  - the circumstances in which NGERAC will be convened;
  - any immunity NGERAC and AEMO may have from liability; and
  - the principles to underpin curtailment tables and gas sharing arrangements;
- formalise the industry's obligations to provide information in emergencies; and
- review jurisdictional curtailment tables to determine whether they are still appropriate and consider whether such tables should be publicly available.

The AEMC understands from the White Paper that a review of the Protocol is to be carried out and considered by the Energy Council in 2015–16.[452] The AEMC will seek to gain further understanding on emergency arrangements and future work plans throughout the review to inform consideration of any potential improvements or gaps in this process.

451 This is a non-binding Memorandum of Understanding that was entered into in 2005 by the Commonwealth, State and Territory governments.

452 Department of Industry and Science, *Energy White Paper 2015*, April 2015, p. 30.

A East Coast Wholesale Gas Market and Pipeline Frameworks Review: Terms of Reference

Background

Australian gas markets are experiencing a rapid transition as conventional gas reserves decline, unconventional gas resources become increasingly important, pipeline and storage infrastructure improves, and the influence of international price trends increase. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering a structural shift in supply and demand, and will lead to significant changes in the pattern and direction of gas flows.

These factors are driving a period of adjustment in the market as uncertainty around future gas prices increases. This is also leading to a renewed focus on market development and the efficiency of the gas supply chain. In particular, the establishment of well-functioning markets (commodity, financial and transportation) is key to promoting the most efficient use of gas, in the long term interests of consumers.

In light of these changing dynamics, the AEMC's 2013 Gas Market Scoping Study highlighted the fragmented nature of gas market development and identified a range of potential issues that may be affecting the efficient operation of the market. Other reviews such the Commonwealth Government's Eastern Australian Domestic Gas Market Study and the Victorian Government's Gas Market Taskforce have also identified areas for reform.

At its December 2014 meeting, the Council of Australian Governments (COAG) Energy Council outlined its vision for Australia's future gas market:

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

This vision is underpinned by the Gas Market Development Plan, which outlines actions the COAG Energy Council will initiate to improve Competitive Supply, Transparency and Price Discovery, Risk Management, and Removing Unnecessary Regulatory Barriers.

In order to assist the Council realise its vision, it is tasking the AEMC to review the design, function and roles of facilitated gas markets and gas transportation arrangements.

The Council, at the request of the Victorian Government, has separately tasked the AEMC to review the Victorian Declared Wholesale Gas Market (DWGM). The two reviews are related in scope and timing, as such the Council expects the findings of the DWGM review will be incorporated in the East Coast Wholesale Gas Market and Pipeline Frameworks Review.

Purpose of the review

The review will consider the role and objectives of the facilitated gas markets currently in operation on the east coast and set out a road map for their continued development in order to meet the Council's vision for the market. Opportunities to improve market outcomes including changes to the market structure to enhance liquidity, improve transparency, more effectively manage risk and support the continued integration of the east coast market will be a key focus.

It will be increasingly important given the growing international influence on the Australian gas market that gas supply can reach its highest value end-use, both domestically and for export, and that trading activities can occur across the interconnected markets with low transaction costs and supported by effective risk management processes.

The review will also consider appropriate regulatory arrangements for efficient access to and use of pipeline capacity in order to deliver appropriate incentives and signals to facilitate efficient and timely investment in gas transportation infrastructure and storage. This will include an assessment of the effectiveness of the existing arrangements and, where necessary, options for reform of these arrangements.

The Council expects the AEMC to develop specific actions that can be implemented to strengthen the structure and competiveness of the east coast gas market. Where possible, the AEMC is to consider making recommendations for immediate implementation.

Scope

The AEMC is required to review the development of the facilitated gas markets and gas transmission pipeline capacity arrangements in eastern Australia. In undertaking the review, the AEMC should consider:

1. Facilitated markets: enhancing transparency and price discovery in the wholesale markets, and reducing barriers to entry

Australia has a number of facilitated markets, which include the DWGM, the Short Term Trading Markets (STTMs) and the Wallumbilla Gas Supply Hub. These markets do not seek to replace the trade of wholesale gas through bilateral contracts, but rather provide additional market options which can lead to greater transparency and price discovery.

The gas supply hub is a voluntary market where sellers offer to sell gas and buyers offer to buy gas with the market operator responsible for matching buyers and sellers at the same price. Transportation does not form part of the transaction. In contrast, the STTM is a wholesale gas balancing mechanism established at defined gas hubs. The objective is to facilitate the short term trading of gas between pipelines, participants and production centres. It uses bids, offers and forecasts submitted by participants and pipeline capacities to determine schedules for deliveries from the pipelines which ship gas from producers to transmission users and the hubs.

The STTMs were designed as wholesale markets overlaid on existing contractual arrangements for supplying gas from multiple facilities to a defined hub to better reflect the current value of gas and provide incentives that improve system reliability. Finally, the DWGM is a single integrated market that provides participants with the ability to trade imbalances and purchase wholesale gas. The DWGM framework has provided a reliable and secure system for the trading and transportation of gas in Victoria.

The AEMC is to consider the optimal type and number of facilitated markets on the east coast, taking into account the current arrangements and changing gas market conditions. The AEMC should assess short and longer term options to improve the accuracy and transparency of market information to enhance the wholesale price discovery process and support competition in upstream and downstream markets. The AEMC should also consider opportunities to harmonise the market parameters of the facilitated markets across the east coast, such as prudential obligations, gas day trading times and market price caps. As each facilitated market is operated differently, there may be opportunities to reduce transaction costs for participants operating in, or looking to participate in, multiple trading hubs.

2. Improving effective risk management in Australian gas markets

Across Australia's facilitated markets, there are varied management techniques to mitigate price risks (long term contracts, or limited capacity instruments). However, the Council is concerned that as the markets develop the ability for participants to hedge risk using these techniques is being impacted.

The Council has committed to establishing the necessary enabling conditions for the development of a liquid trading market for the eastern gas market, including through access to transmission pipelines. The AEMC is to provide advice on the adjustments necessary in the markets and regulatory arrangements governing pipeline access to facilitate liquid and competitive wholesale spot and forward markets which also provide tools for participants to price and hedge risk. In particular, the AEMC should investigate the issues associated with, and potential benefits of, the development of an efficient financial derivative market for gas.

3. Signals and incentives for efficient access to and use of pipeline capacity

Pipeline capacity in Australia has grown steadily in recent years providing a greater degree of interconnectedness between gas supply resources and demand centres. The current framework has successfully brought new capacity on line to meet demand and allocated costs to the beneficiaries of the investment. While recognising that the current framework has delivered investment, the Council has committed to examining the access arrangements governing gas pipelines, reducing any barriers to access and facilitating continued pipeline investment, as enabling conditions for more liquid gas markets in both the short and longer term.

The AEMC is to consider whether the provision of accurate and transparent information on pipeline and storage operations, and capacity, is appropriate and whether there are impediments to the efficient use and opportunities for trade in pipeline capacity. This may include more structured or harmonised capacity contracting arrangements.

Further, the Council expects the AEMC to recommend changes to the design of the markets that will, strengthen signals and incentives for efficient investment in, access to, and use of pipeline capacity across eastern Australia.

In making its recommended changes, the AEMC should consider any implications for the existing transmission access and investment framework, including the importance of existing property rights within that investment framework.

Considerations

In undertaking the review and forming its recommendations, the AEMC is to consider the:

- Size, maturity and interconnectedness of the east coast gas market;
- Types and needs of participants including producers, transporters, retailers and end users (large and small manufacturers, small business and households);
- Changes being driven by the establishment of the LNG export industry;
- Physical characteristics of the market as a whole as well as the particular locations serviced by any facilitated market;
- Legal and regulatory arrangements supporting pipeline access;
- Costs and benefits of any recommendations;
- Nature of the commercial arrangements underpinning the supply and transportation of gas; and
- Relevance of international experience to the development of the east coast gas market

The AEMC is also to incorporate the findings and recommendations from its concurrent review of the DWGM.

More broadly, the AEMC is also to consider the:

- National gas objective; and
- COAG Energy Council's Gas Market Vision and Gas Market Development Plan.

Consultation, timeframes and deliverables

The review will be conducted over two phases. The first phase will develop the overall direction for east coast market development to support the Council's vision. Drawing on a fact-base of the current market outcomes the report will provide a gap analysis between the Council's vision and the existing market design including an assessment of whether options currently being discussed and included in the Gas Market Development Plan could address the gap. Recommendations in the Phase 1 report will highlight specific actions for immediate implementation and identify any rule change recommendations for the Council's consideration. The second phase will more fully develop the medium and long term adjustments necessary to implement the Council's vision including the transition path required.

The AEMC will provide the Phase 1 report to the Council in June, 2015 to allow the Council to be considering rule change recommendations from that work while the Phase 2 work is ongoing. This should allow for a faster implementation timeline. A draft Phase 2 report will be provided to the Council ahead of the December meeting. This will give the Council the ability to assess whether further work on the potentially more transformative recommendations is still required as well as speeding up any final decisions from the Council on rule change requests.

Despite an accelerated timeline for this work the AEMC will hold public forums/workshops on both phases of work and invite participants to make written submissions to presentations and working papers distributed in the forums.

A single stakeholder reference group will also be convened to provide input and guidance on this review, as well as the AEMC review of the DWGM. The reference group will meet periodically and the AEMC will use best endeavours to ensure the members include AEMO, AER, pipeline owners, retailers, producers, consumer representatives and any other party the AEMC deems appropriate. The AEMC will also provide regular updates and seek regular feedback from the Gas Market Working Group.

The AEMC is to work closely with AEMO throughout the review to utilise AEMO's expert advice in assessing the operational implications of any recommendations.

Milestone	Due Date
Stage 1: setting the directions for east coast markets	
Public forum (seek written submissions)	February 2015
Draft report for consultation	April 2015
Final report to COAG Energy Council	June 2015
Stage 2: addressing the medium to long term issues	
Directions paper and public forum	August 2015
Draft report for consultation, including request for COAG response on any longer term initiatives	December 2015
Final report to COAG Energy Council	Following COAG Energy Council's response to the draft report

B Victorian Declared Wholesale Gas Market Review: Terms of Reference

Background

The Victorian Government recognises that improvements may be made to the operation and efficiency of the eastern Australian gas market, to better facilitate market transparency and transmission capability, and increasing gas supply to meet rising demand at competitive prices.

The Victorian Declared Wholesale Gas Market (DWGM) is a single integrated market that provides participants with the ability to trade imbalances and purchase wholesale gas. The market was established by the Victorian Government in March 1999 to support full retail contestability and encourage diversity of supply and upstream competition.

The DWGM is operated by the Australian Energy Market Operator (AEMO). Between 1999 and 2007, the gas price was determined on a daily ex-post basis. From 2007, the market moved to ex-ante intra-day trading following a review by VENCorp in 2003-04, which found that the existing design did not provide participants with the ability to respond to changing market conditions throughout the day.

The DWGM facilitates trading and balancing arrangements for gas market participants, including retailers, gas-fired generators, large industrial users and producers. Since the inception of the DWGM, the market design has stimulated a competitive retail gas market and safeguarded the security of gas supply for Victorian customers. Currently, there are eight gas retailers competing in the retail market and six gas-fired generators connected to the Victorian Declared Transmission System (DTS). Notwithstanding this, substantial developments are set to impact the market over the next few years.

In response to the establishment of a liquefied natural gas (LNG) export industry, the east coast gas market will experience a structural change to demand and supply. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect Pipeline or Eastern Gas Pipeline. With exports set to begin from late-2014, the domestic market is already feeling the effects of greater competition for gas. These developments are expected to put upward pressure on gas prices and have resulted in a renewed focus on the efficiency of the gas supply chain.

Given the uncertainty around market outcomes for participants, gas market arrangements need to be flexible enough to support a range of potential scenarios out past 2020. It will be important for end users, such as industrial and commercial customers, as well as retailers, to have the ability to effectively manage risk in the DWGM. To minimise inefficient congestion on the DTS, investment to expand the DTS needs to occur in a timely and efficient manner. Interaction between the DWGM and adjacent gas markets should also be as seamless as possible, as this will reduce transaction costs and unnecessary volatility for market participants, minimising costs for end users of natural gas.

It is critical that a review of the Victorian DWGM be undertaken to examine whether the significant structural changes underway in the eastern gas market require reforms to enhance the liquidity, transparency and flexibility of the current arrangements.

In this context, the Victorian Government has requested that the Australian Energy Market Commission undertake, in consultation with AEMO, a thorough review of pipeline capacity, investment, planning and risk management mechanisms in the Victorian DWGM. The objective of this undertaking is to ensure arrangements for access to the pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.

The AEMC will undertake the review in accordance with this Terms of Reference and provide a report with recommendations to the Victorian Government for consideration. The Victorian Government notes that the COAG Energy Council has separately tasked the AEMC with reviewing the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast. The two reviews are related in scope and similar in timing and it is expected that the relevant findings and recommendations to be reflected in both reviews (where appropriate).

Purpose

The review is to consider whether the DWGM provides appropriate signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates the efficient trade of gas to and from adjacent markets. More broadly, the review is to consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long term interest of consumers.

These Terms of Reference are intended to guide the AEMC's review of the Victorian DWGM.

Scope

The AEMC is required to undertake a review of the Victorian DWGM that considers:

1. Effective risk management in the DWGM: the ability of market participants to manage price and volume risk in the DWGM and options to increase the effectiveness of risk management activities.

The Victorian Government is concerned that an inability for market participants to effectively hedge risk in the DWGM is limiting the potential of the market to achieve greater transparency and efficiency of trade in natural gas.

The ASX Victorian Wholesale Gas Futures Product is available but not widely traded as it can only be used to hedge against the ex-ante market price and not uplift charges. Further, while Authorised Maximum Daily Quantity (AMDQ) and AMDQ credit certificates provide participants with some protection against uplift charges, they cannot be used as a hedge against surprise or common uplift charges.

The AEMC is to investigate the underlying issues that are preventing greater use of derivatives and other risk management tools in the DWGM, outline the features of an efficient financial derivative market for gas and the changes that would need to be made in the DWGM to facilitate this.

2. Signals and incentives for efficient investment in and use of pipeline capacity: whether market signals and incentives are providing for efficient use of, and efficient and timely investment in, pipeline capacity on the DTS.

Investment decisions to augment the DTS are currently largely made in response to a five year regulatory determination process. While the DWGM arrangements provide a form of tradeable pipeline capacity rights, through AMDQ and AMDQ credits, these rights have limitations in terms of providing certainty of access when the pipeline is constrained, and in allowing “free-rider” access when spare capacity is available. Consequently, they have been of limited effect in supporting private pipeline investment in the DTS. Investment guided by regulatory processes may be less efficient and timely than relying on market driven incentives. If firm, tradeable access rights to pipeline capacity were available, in a form that addressed these current limitations, this may enhance private investment, as prices for the access rights would signal the need for future investment.

The AEMC is to investigate whether investment in the DTS is expected to continue to occur in a timely and efficient manner. This investigation should also consider the interaction between regulated and private investment and whether the costs of pipeline investment and usage are allocated to users on an equitable basis. If appropriate, the AEMC is to recommend changes to strengthen the signals and incentives for efficient investment, and enhance access to, and short term trading of, pipeline capacity.

3. Trading between the DWGM and interconnected pipelines: To maximise the efficiency of trade in natural gas and facilitate competition in upstream and downstream markets, producers and shippers should be able to effectively operate across the different gas trading hubs on the east coast without incurring substantial transaction costs.

The AEMC is to examine if, and to what extent, the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines. Elements like transparent, adaptable pricing between the DWGM and interconnected pipelines, combined with ready access to pipeline capacity, may be required to enable shippers to better manage risk and facilitate the efficient trade of gas between interconnected hubs and pipelines.

In considering items 1 and 2 above, the AEMC should examine alternative pricing, risk management and pipeline access mechanisms for the DWGM that would also enhance efficient trading of gas with interconnected pipelines and facilities.

4. Promoting competition in upstream and downstream markets: whether the DWGM arrangements continue to facilitate market entry and promote competition in upstream and downstream markets and how this could be improved.

Taking into account the analysis and any recommendations from the areas of review above, the AEMC should assess whether the DWGM continues to effectively encourage the introduction of new gas supplies to the market and promote competition among retailers in the sale of gas. The AEMC should also comment on the extent to which the design of the DWGM may be a deterrent to large users of gas from participating in the market where it may otherwise be commercially practical for them to do so, and the extent to which this may have an adverse impact on gas usage, trading and market liquidity.

If the AEMC proposes recommendations for market reform, it should clearly demonstrate to the Victorian Government and Council of Australian Government's (COAG) Energy Council how the recommendations address the issues identified, that they continue to safeguard the security of gas supplies to Victorian customers, are proportionate to the problem being addressed and how they promote the national gas objective.

Considerations

In undertaking the review and forming its recommendations, the AEMC is to consider:

- the physical characteristics, size, maturity and interconnectedness of the Victorian gas market;
- the nature of the commercial arrangements underpinning the supply and transportation of gas;
- developments in other eastern Australian gas markets; and
- relevant international experience.

The AEMC is also to consider and incorporate (where appropriate) the findings and recommendations from its concurrent review of Australia's facilitated gas markets.

More broadly, the AEMC is also to consider.

- the National Gas Objective; and
- the COAG Energy Council's Gas Market Development Plan.

Consultation

The Victorian Government requires that the AEMC undertake a formal stakeholder consultation process, including the release of an issues paper, options paper and a draft report for consultation at minimum. If considered appropriate, the AEMC should also hold public forums and/or workshops.

The AEMC is required to establish a stakeholder reference group that will meet periodically throughout the review and prior to the completion of each of the review milestones, and comprise membership of AEMO, representatives of pipelines, consumers, retailers, producers, large users and any other party the AEMC deems appropriate. This stakeholder reference group will also be used for the AEMC's review of facilitated gas markets on the east coast and additional Victorian-specific representatives may be invited.

The AEMC is to utilise the experience of the Australian Energy Regulator as appropriate.

Timeframes and deliverables

The AEMC is to undertake the review over a maximum period of 18 months, taking into consideration the indicative timeframes set out below. This will allow the AEMC to undertake extensive engagement with stakeholders and propose well developed recommendations to the Victorian Government.

The Victorian Government notes that these timeframes represent an upper bound and the AEMC should use its best endeavours to complete each stage of the review promptly and ahead of schedule. Public consultation should be for a minimum of four weeks for each report and a copy of the draft and final reports must be provided to Victorian Government officials and the COAG Energy Council officials one week before publication.

Milestone	Timing
Public forum (in conjunction with the Review of Facilitated Markets)	February 2015
Issues Paper	April 2015
Options Paper	August 2015
Publish Draft Report, including request for Victorian Government response on any significant initiatives identified by the AEMC	December 2015
Final Report	The final report will be published following receipt of the Victorian Government's response to findings and recommendations in the draft report

Before finalising a detailed implementation plan for its proposals in the final report, the AEMC will seek a formal response from the Victorian Government and the COAG Energy Council to some of its recommendations in the draft report.[453]

453 For example, if the AEMC proposes significant changes to the National Gas Rules, the AEMC will seek a response from the COAG Energy Council at the draft report stage before finalising the review.

C Summary of previous reviews of the east coast gas markets

Table C.1 Relevant recommendations from previous east coast gas market reviews and actions

Recommendation	Action
Gas Market Scoping Study[454]	
High Priority Undertake a strategic review that considers both: • the directions that the eastern Australian gas market should take over the next 10-15 years, if it is to make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports: the efficient allocation of gas in the short, medium and longer-term; the efficient trade and movement of gas between jurisdictions; efficient and timely investments in upstream production and transportation capacity; the efficient allocation of risks; and the development of financial markets that can be used by participants to hedge risks. As part of this assessment, consideration would ideally be given to whether the existing facilitated markets (ie the DWGM and STTM) are meeting their stated objectives in the most efficient manner; and if not, how this could be addressed; and • the principles that should guide the development and design of facilitated markets in the future. SCER (now the COAG Energy Council) to sponsor review; AEMC to carry out review.	At its December 2014 meeting, the COAG Energy Council reaffirmed its commitment to the NGO and outlined its Vision for the east coast gas market. In order to assist the Council realise its Vision, it tasked the AEMC to review the design, function and roles of the facilitated gas markets and gas transportation arrangements. The first stage of this Review will be provided to the Council by mid-2015. The second stage of this review will more fully develop the any necessary medium and long term adjustments required to implement the Energy Council's Vision, including the transition path required.
High Priority Undertake a detailed review of the design of the STTM and particular design elements of the DWGM and determine whether improvements can be made to the existing design that would better promote the NGO. AEMC and SCER to jointly draft terms of reference; SCER to determine whether AEMC and/or AEMO should carry out the review once scope of work defined.	

454 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, pp. iii-iv.

Recommendation	Action
Medium Priority Investigate ways of reducing the time taken to develop and implement STTM and DWGM rule changes and streamline the consultation process (AEMO and AEMC).	The AEMC can expedite non-controversial rule changes under section 304 of the NGL, subject to requests not to do so, and assessed the Removal of the Gas Bulletin Board Emergency Information Page Proposal rule change on an expedited basis. The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL (which restricts parties other than AEMO and Ministers of adoptive jurisdictions from submitting DWGM rule changes). For more information, see Chapter 5.
Medium Priority Two review options that could be taken to promote investment outcomes in the Victorian Declared Transmission System (DTS) are: • Option 1: undertake a holistic review of the regulatory investment process and application of this process in Victoria; and/or • Option 2: undertake a preliminary internal review of the prospects for introducing tradeable transmission rights and proceed to a more detailed public review if tradeable transmission rights are considered likely to provide improved investment signals in the DTS. SCER to sponsor the review; AEMC to carry out the review.	The COAG Energy Council, at the request of the Victorian Government, has tasked the AEMC to undertake a review of pipeline capacity, investment and risk management mechanisms in the Victorian DWGM. This report forms part of Stage 1 of the review.
Medium Priority Consideration to be given to how to reduce search, transaction and co-ordination costs associated with spot or very short term capacity trades (ie capacity trades for periods less than 1 month) to facilitate the form of capacity trading by shippers (Industry led).	There are now four websites listing capacity trading opportunities: AEMO's Bulletin Board and Gas Supply Hub websites, as well as capacity trading websites managed by APA and Jemena for their respective pipelines.[455] See Chapter 4 for more information on capacity trading. Further opportunities to facilitate short term capacity trades will be considered in the second stage of this review.

455 For more information refer to AEMO's Gas Market Bulletin Board at http://www.gasbb.com.au/Transmission%20Capacity%20Listing.aspx

Recommendation	Action
Low priority Assessment of whether greater consistency between market parameters in the NEM and imbalance markets to be carried out as part of the STTM and DWGM design review (AEMC and/or AEMO).	Opportunities to improve consistency between market parameters and interactions between the NEM and imbalance markets are discussed in Chapters 5 and 6, and will be considered further in the review.
Low priority If there is a significant change in climate change policies and/or conditions in the NEM that support gas fired generation, then a more detailed review could be undertaken to get a better understanding of the interactions between the two markets and to ensure existing arrangements are fit for purpose. SCER to sponsor review; AEMC to carry out review.	
Low priority Be cognisant of the potential for higher wholesale gas prices to prompt jurisdictions to implement a cap on retail prices that is lower than the efficient cost of supply. If there is any indication this may occur, liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition (AEMC).	
Low priority Consider whether any additional operators should be designated Bulletin Board facility operators; and consider whether improvements can be made to the quality and accessibility of existing STTM, DWGM and Bulletin Board data (AEMO).	In December 2014, AEMO completed a major upgrade to the Gas Market Bulletin Board. The upgrade was implemented to improve the "useability, availability and reliability of gas data for all participants in the south-east and east coast gas markets".[456] Further opportunities to improve information quality and accessibility are set out in Chapter 8 and will be considered further in the second stage of this Review.
Other Refer stakeholder comments on the effect of the restriction set out in section 295(3) of the NGL on DWGM related rule changes to the Victorian Government and allow it to consider whether there is still a rationale for having this restriction and, if so, whether any improvements could be made to the current process (AEMC to refer to Victorian Government).	The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL. For more information on the DWGM, see Chapter 5.

456 http://www.aemo.com.au/News-and-Events/News/2014-Media-Releases/AEMO-Launches-New-National-Gas-Market-Bulletin-Board

Recommendation	Action
Other Refer stakeholder comments on emergency arrangements and our high level observations about the need: to improve the transparency and accessibility of these arrangements; formalise the obligations industry have to provide information in emergencies; review jurisdictional curtailment tables; and consider whether such tables should be publicly available (AEMC to refer to SCER).	The Australian Government's Energy White Paper notes the Energy Council will review the National Gas Emergency Response Protocol Memorandum of Understanding to ensure that natural gas supply interruptions are managed in a nationally consistent manner in 2015-16.[457] The AEMC will seek to gain further understanding on emergency arrangements and future work plans throughout the review to inform consideration of any potential improvements or gaps.
Gas Market Taskforce[458]	
Recommendation 13 Eastern market governments, through SCER [now the COAG Energy Council], accelerate and enhance the implementation of existing reforms under the National Gas Market Development Plan: • pursuing ways of making the voluntary markets for transmission capacity more transparent, flexible, efficient and liquid; • investigating options for developing uniform transmission capacity rights and pursue ways of facilitating more transparent and liquid trade in transmission capacity; • identifying and removing barriers to trading in gas across different downstream markets in order to move towards more consistency and, as far as practicable, a single market design; • drawing on relevant experience from gas markets in other countries, such as the United States, the United Kingdom and continental Europe; and • establishing key performance measures in gas market reform, assessing responsibility for delivering them, and annually commission a review of success and consider further facilitation of market development.	At its December 2014 meeting, the COAG Energy Council updated the National Gas Market Development Plan.[459] Progress toward existing reforms is summarised below: • the Wallumbilla Gas Supply Hub commenced in March 2014 and; • on 30 March 2015, the Energy Council submitted a rule change request to the AEMC to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board. Opportunities to further facilitate trade in transmission capacity and to improve market design, information quality and accessibility are discussed in this report and will be considered further in Stage 2 of this Review. Further, in order to inform this Review, the AEMC has commissioned a study on international gas markets and transmission pipeline frameworks, including in the United States, United Kingdom and some European markets. The study is expected to be published with the AEMC's final Stage 1 report in June 2015.

457 Australian Government, Energy White Paper, 2015, p. 30.

458 Victorian Government, *Gas Market Taskforce*, Final Report and Recommendations, October 2013, pp. 7-8.

459 http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

Recommendation	Action
Recommendation 16 The Victorian Government immediately request the AEMC undertakes, in consultation with AEMO, a thorough review of pipeline capacity, investment, planning and risk management mechanisms in the DWGM with the objective of ensuring arrangements for access to pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.	The COAG Energy Council, at the request of the Victorian Government, has separately tasked the AEMC to undertake a review of pipeline capacity, investment, planning and risk management mechanisms in the DWGM. This report forms part of Stage 1 of the review.
Recommendation 17 The Victorian Government to consider whether arrangements for rule-making in the DWGM are adequately responsive to the gas industry given the challenges it is facing.	The AEMC is recommending that the Energy Council consider the appropriateness of section 295(3) of the NGL. For more information on the DWGM, see Chapter 5
Eastern Australian Domestic Gas Market Study[460]	
Gas Market Reform Agenda 1. Consider commissioning a review of gas market competition to focus on matters driving wholesale market outcomes; 2. Complete current SCER [COAG Energy Council] reforms (especially commence Wallumbilla hub and support pipeline capacity trading); and 3. Agree a forward gas market reform agenda in consultation with stakeholders: (a) develop principles to guide policy on commodity, transportation and financial markets; and (b) conduct specific reviews on the direction and structure of the existing trading and related financial markets.	At its December 2014 meeting, the Council reaffirmed its commitment to the NGO, updated the National Gas Market Development Plan and set out its vision for Australia's Future Gas Market.[461] In order to assist the Council achieve the vision, it request the AEMC review the design, function and roles of the facilitated gas markets and gas transportation arrangements. The Wallumbilla Gas Supply Hub commenced in March 2014. On 30 March 2015, the Energy Council submitted a rule change request to the AEMC to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board

460 Department of Industry (Australian Government), *Eastern Australian Domestic Gas Market Study*, January 2014, p. 90.

461 COAG Energy Council, Communique, December 2014 https://scer.govspace.gov.au/files/2014/05/COAG-Energy-Council-Communique-11-Dec-2014-FINAL2.pdf

Recommendation	Action
Improve the commercial and regulatory environment for infrastructure 1. Improve information to markets and regulators on pricing and utilisation of infrastructure; 2. Review suitability of carriage models for pipeline regulation; 3. Consider support for infrastructure feasibility studies; and 4. Enhanced pipeline capacity trading and develop a roadmap and evaluation process around future development of pipeline capacity trading.	The suitability of pipeline carriage models and options to enhance pipeline information and capacity trading are discussed in Chapters 4 and 8 of this report. and will be considered further in the second stage of this Review.
Market data and transparency 1. Improve planning on transparency mechanisms such as the Gas Statement of Opportunities and Bulletin Board and industry initiatives (eg price indices, pipeline information).	Options to improve gas market information are discussed in Chapter 8 and will be considered further in the second stage of this Review.

D Third party access regime applying to transmission pipelines

D.1 Introduction

The third party access regime applying to pipelines is set out in the National Gas Law (NGL) and the National Gas Rules (NGR), both of which came into effect on 1 July 2008. Prior to 1 July 2008, covered pipelines were subject to the access regime and regulatory framework set out in the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), which were enacted in late 1997.

While there are some parallels between the access regime applying to gas pipelines and electricity networks, there are also some important points of distinction. For example:

- The gas access regime is more akin to the negotiate-arbitrate model in Part IIIA of the *Competition and Consumer Act 2010* (CCA) than the model used in electricity;[462]
- The economic regulatory provisions in the NGR only apply to covered pipelines;
- A covered pipeline may be subject to either full or light regulation;[463]
- Provision has been made in the NGL for a pipeline's coverage status and/or the form of regulation to be altered over time if conditions change and certain criteria are met;
- Provision has also been made in the NGL for:
  - a greenfields pipeline to be exempt from coverage for 15 years; and
  - a new international pipeline to be exempt from price regulation, or coverage, for 15 years.[464]

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462 This point can be seen in section 322 of the NGL, which states that subject to section 135, nothing in the NGL is to be taken as preventing a service provider from entering into an agreement with a user or a prospective user about access to a scheme pipeline that is different from an applicable access arrangement.

463 The only exception to this is if the scheme pipeline has been deemed a "designated pipeline." A designated pipeline is a pipeline classified by the Regulations, or designated in the application Act of a participating jurisdiction, that cannot be subject to light regulation. The pipelines that are currently designated include AGNL's SA Distribution Network, ATCO's Western Australian gas distribution system, the three Victorian gas distribution systems and the DTS. See National Gas (South Australia) Regulations 2009, National Gas Access (WA) (Part 3) Regulations 2009, Schedule 1 and Victorian Government Gazette No. S222m, 30 June 2009.

464 An international pipeline is defined as a pipeline for the haulage of gas from a foreign source.

The remainder of this appendix provides further detail on the third party access regime and form of regulation provisions in the NGL and NGR, with particular emphasis placed on:

- the background to the development of the these aspects of the regulatory framework;
- how coverage, revocation of coverage and 15 year no-coverage decisions are made; and
- the alternative forms of regulation provided for under the NGL and NGR.

D.2 Background to the development of the current regulatory framework

The third party access regime and regulatory framework currently applying to gas pipelines was developed through two distinct phases of reform. The first phase, which extended from 1991 to 2002, focused on:

- the removal of government imposed constraints on the free and fair trade of gas;
- the development of a framework for third party access to transmission and distribution pipelines on non-discriminatory terms and conditions; and
- the structural reform of the vertically integrated government owned transmission and distribution assets and the privatisation of government owned pipelines and retailing.

In the second phase of reforms, which commenced in 2002 and culminated in the enactment of the NGR and NGL in 2008, the reform agenda shifted focus from structural reforms and access provision, to addressing some of the perceived deficiencies in the regulatory and governance frameworks.

D.2.1 First phase of reforms (1991–2002)

The pre-cursor for the first phase of reforms was a report prepared by the Industry Commission in 1991 entitled, "Energy Generation and Distribution," which contained a number of recommendations on how to remove impediments to the efficient allocation of gas.[465] Between 1992 and 1994, COAG agreed to implement many of the Industry Commission's recommendations including:[466]

- the removal of legislative and regulatory barriers to inter and intra-jurisdictional trade and the use of gas for certain activities to facilitate the free and fair trade of gas;
- the introduction of complementary legislation to enable a national framework for third party access to gas transmission pipelines to be introduced;
- increased commercialisation of the operation of public owned gas pipeline assets; and

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465 Industry Commission, *Energy Generation and Distribution*, 17 May 1991.

466 National Competition Council, *Compendium of National Competition Policy Agreements*, 2nd ed., 1998, pp. 70-71.

- the vertical separation of publicly owned transmission and distribution assets.

At the same time that these reforms were being progressed by COAG, the Independent Committee of Inquiry (Hilmer Review) was considering the reforms that would be required to develop a national competition policy.[467] In April 1995, the recommendations flowing from the Hilmer Review were adopted by COAG and implemented through the Competition Principles Agreement (CPA). A key element of the CPA was the decision to allow third party access to services provided by significant infrastructure facilities, through the development of a national access regime that was introduced into Part IIIA of the *Trade Practices Act 1974* (now the *Competition and Consumer Act 2010* (CCA)) (see Box D.1).

Box D.1 Part IIIA of the CCA

Under Part IIIA there are three avenues through which access to an infrastructure service can occur:

1. Through a declaration by the relevant Minister that the services satisfy all of the following criteria.
   - (a) access (or increased access) to the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service;
   - (b) it would be uneconomical for anyone to develop another facility to provide the service;
   - (c) the facility is of national significance, having regard to:
     - (i) the size of the facility; or
     - (ii) the importance of the facility to constitutional trade or commerce; or
     - (iii) the importance of the facility to the national economy.
   - (d) [repealed]
   - (e) access to the service is not already the subject to an effective access regime; and
   - (f) access (or increased access) to the service would not be contrary to the public interest.

If a service is declared then the parties must negotiate the terms and conditions of access to the service. If an agreement can’t be reached then the access dispute provisions can be triggered.

2. Through a legally enforceable access undertaking (a document setting out the terms and conditions on which access will be provided, including the price of access), which is voluntarily submitted by the asset owner to the Australian Competition and Consumer Commission (ACCC) for its approval;
3. Through a state or territory access regime that has been certified as an effective regime by the Commonwealth Minister because it complies with the Competition Principles Agreement.

467 Independent Committee of Inquiry, National Competition Policy, August 1993, p. xvii.

While access to gas pipelines could have been facilitated by the generic national access regime in Part IIIA, COAG decided that an industry specific access regime should be developed to enhance certainty, uniformity and consistency outcomes that were expected to assist with the expansion of the market for gas and encourage investment in pipelines. Elaborating further on this decision, COAG noted that the access regime "involves a balance between flexibility, required to deal with the individual circumstances of pipelines and customers, and a level of prescription to ensure consistency of treatment." [468]

Some of the principles that COAG agreed should underpin this access regime are reproduced below:[469]

- pipeline owners and/or operators should provide access to spare pipeline capacity for all market participants on individually negotiated non-discriminatory terms and conditions;
- information on haulage charges, and underlying terms and conditions, to be available to all prospective market participants on demand;
- if negotiations for pipeline access fail, provision be made for the owner/operator to participate in compulsory arbitration with the arbitration based upon a clear and agreed set of principles;
- pipeline owners and/or operators maintain separate accounting and management control of transmission of gas;
- provision be made for access by a relevant authority to financial statements and other information necessary to monitor gas haulage charges; and
- contracts, between producers and consumers for the supply of gas, entered into prior to the enactment of gas reform legislation would not be overturned by that legislation.

The industry specific regime was set out in the Gas Code, which was given legislative effect in each jurisdiction through the GPAL. The overarching objective of the Gas Code, as stated in its introduction, was to establish a nationally consistent framework for third party access to "covered" pipelines that would:

- facilitate the efficient development and operation of a national natural gas market and integrated pipeline network;
- promote a competitive market for gas, in which customers are able to choose the supplier they want to trade with;
- provide rights of access on fair and reasonable terms to users and service providers and prevent the abuse of market power by service providers; and
- provide a mechanism for the resolution of disputes in circumstances where a prospective user and the service provider were unable to reach commercial agreement.

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468 House of Representatives, Australia 1998, Gas Pipelines Access (Commonwealth) Bill 1997, Explanatory Memorandum, paras 32-33.

469 NCC, Compendium of National Competition Policy Agreements, January 1997, p. 67. These principles were agreed to on 25 February 1994.

Box D.2 provides an overview of the key elements of the Gas Code.

Box D.2 Key elements of the Gas Code

The key elements of the Gas Code were:

- Schedule A, which contained a list of transmission and distribution pipelines that would be covered from the commencement of the Gas Code. This list included most of the pipelines that had been built before the Gas Code came into effect.
- The coverage provisions, which largely mirrored the declaration and access undertaking provisions in the Part IIIA of the CCA and allowed:
  - a pipeline to become covered if it satisfied all of the coverage criteria (or for coverage to be revoked if one or more criteria were not satisfied);
  - a service provider to voluntarily become covered by submitting a proposed access arrangement (AA) to the regulator for approval; and
  - a pipeline to become covered if it was developed through a competitive tender process that was approved by the relevant regulator.
- The access regulation provisions, which required service providers of covered pipelines to prepare an AA and have the terms and conditions upon which it would provide reference services to third parties and the reference tariff payable for each reference service approved by the relevant regulator. While reference tariffs had to be approved by the regulator, the Gas Code allowed service providers and access seekers to agree to terms and conditions (including the tariff) that differed from those set out in the AA. The reference tariff was therefore seen as a benchmark for access negotiations on contract carriage pipeline.[470]
- The dispute resolution mechanism, which could be accessed by shippers and the service provider if a dispute about access, or the terms and conditions of access arose. While the Gas Code explicitly recognised that users and service providers could agree to alternative terms and conditions (including tariffs) to those specified in the AA, the dispute resolution provisions required the arbitrator to apply the provisions of the AA in the event of a dispute.
- The information disclosure requirements.
- The ring fencing provisions, which were designed to prevent a service provider from: carrying on a related business (ie production, purchase or sale of natural gas); and conferring an unfair advantage on an associate that takes part in a related business.
- The merits review provisions, which could be triggered for coverage and regulatory decisions.

470 In the DTS it is not possible to negotiate an alternative transportation service because it is operated on a simple injection/withdrawal basis. All users of the DTS therefore pay the reference tariff.

D.2.2 Second phase of regulatory reforms (2002–2008)

Following a series of reviews, including the independent review of the strategic direction for energy market reform that was chaired by Warwick R. Parer,[471] the Productivity Commission's 2003-04 review of the gas access regime,[472] and the 2006 Expert Panel report on energy access pricing,[473] COAG decided to implement a new legal, governance and regulatory framework. This new framework commenced on 1 July 2008 and was given effect through the NGL and NGR.[474]

The NGR and NGL are founded on the same negotiate/arbitrate principles as those underpinning the Gas Code and contain broadly similar provisions on coverage,[475] ring fencing, access arrangements, price and revenue regulation, and dispute resolution as those adopted in the Gas Code and GPAL. There were, however, a number of important refinements made to the regulatory framework, including:

- the implementation of an overarching objects clause, the National Gas Objective, and revenue and pricing principles in the NGL;
- introducing the phrase "material increase in competition" into criterion (a) of the coverage criteria to bring it into line with amendments to the declaration criteria that had been recommended by the Productivity Commission;
- the establishment of the Bulletin Board, which imposed obligations on both regulated and unregulated market participants to provide information to AEMO;
- the inclusion of a 15 year no-coverage option for greenfields pipelines;[476] and
- the introduction of a lighter handed form of regulation.

The last of these refinements was made in response to recommendations by both the Productivity Commission and the Expert Panel (see Box D.3) that:[477]

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471 Parer, Warwick R, Towards a Truly National and Efficient Energy Market, 20 December 2002.

472 In 2003, the Productivity Commission was asked to conduct a review into the gas access regime. In its final report to the Commonwealth Treasurer in 2004, the Productivity Commission raised a number of concerns about the potential for regulation to lead to inefficient investment because of the potential for regulatory error, regulatory risk and asymmetric truncation. The Productivity Commission also recommended a number of changes to the gas access regime, including, amongst others: • introducing an overarching objects clause and clear pricing principles; • ensuring consistency between the coverage criteria and recent amendments to the declaration criteria in Part IIIA of the CCA; • introducing a light handed regulatory option; and • allowing binding 15 year no-coverage ruling to be sought by greenfield pipelines to "reduce the potential chilling effect of regulation on greenfield investments." Productivity Commission, Review of the Gas Access Regime, 11 June 2004.

473 Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy, April 2006.

474 Unlike the GPAL and Gas Code, the NGL/NGR has not been subject to a formal review by the NCC to determine whether it constitutes an effective access regime for the purposes of Part IIIA of the CCA. This issue was recently considered by the Productivity Commission as part of its review into the National Access Regime and it concluded that, on balance, the costs of certifying the gas and electricity regimes may outweigh the benefits. See Productivity Commission, National Access Regime, 25 October 2013, p. 23.

475 In the NGR reference is made to "Scheme Pipelines" which include covered pipelines

476 This provision was included in the GPAL in 2006.

- the degree of regulatory intervention should be commensurate with the degree of market power possessed by the service provider; and
- a less intrusive form of regulation should be applied when a service provider is unable to exercise a substantial degree of market power, because the gap between the price it charges and the "efficient price" is likely to be small and, as a consequence, the costs of full regulation are likely to outweigh the benefits.

Box D.3 The rationale for light regulation

The Productivity Commission recommended the inclusion of a lighter-handed form of regulation in the gas access regime as an alternative to full regulation where the costs of full regulation are likely to exceed the benefits. Elaborating further on this recommendation, the Productivity Commission noted:[478]

> "Regulation with access arrangements with reference tariffs should be applied only where the net benefits of access arrangements with reference tariffs are markedly greater than the net benefits of the monitoring option. Where the difference in net benefits are marginal or the net benefits of the monitoring option are greater than the net benefits of access arrangements with reference tariffs, then the monitoring option [light regulation] should be applied."

The Productivity Commission went on to add that:[479]

> "...the marginal benefit of intervening [through full regulation] decreases as the gap between the 'efficient price' and the 'monopoly price' narrows. Thus, for pipelines that are not exerting substantial market power (that is, where the price gap is narrow), the marginal benefit of intervening is lower."

The Productivity Commission's recommendation to allow a lighter handed form of regulation to be applied when the market power of a pipeline is constrained was echoed by the Expert Panel in its 2006 report to the MCE:[480]

> "The Panel's overall conclusion is that direct price or revenue controls should be applied principally to services supplied under conditions of natural monopoly and substantial market power. These conditions can be identified by having regard to the presence of economies of scale and scope, network externalities and other market characteristics which give rise to the presence of high barriers to entry by potential rivals. Less intrusive forms of regulation or no regulation at all are warranted where there is evidence of potential or actual competition sufficient to discipline the conduct of incumbent service providers and the barriers to entry are modest or low."

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477 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. 228 and Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 51.

478 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p. 228.

479 Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004, p.332.

480 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p.51.

Further detail on the alternative forms of regulation that are provided for under the NGL and NGR is contained in Chapter 4.

D.3 Coverage, revocation and 15 year no-coverage decisions

A pipeline may become covered in one of four ways under the NGL:

- the pipeline was listed in Schedule A of the Gas Code as a covered pipeline;
- the relevant Minister is satisfied the pipeline meets **all** the coverage criteria in section 15 of the NGL (see Figure D.1);
- an unregulated pipeline voluntarily submits an access arrangement to the AER; or
- the pipeline is developed through a tender process approved by the AER.

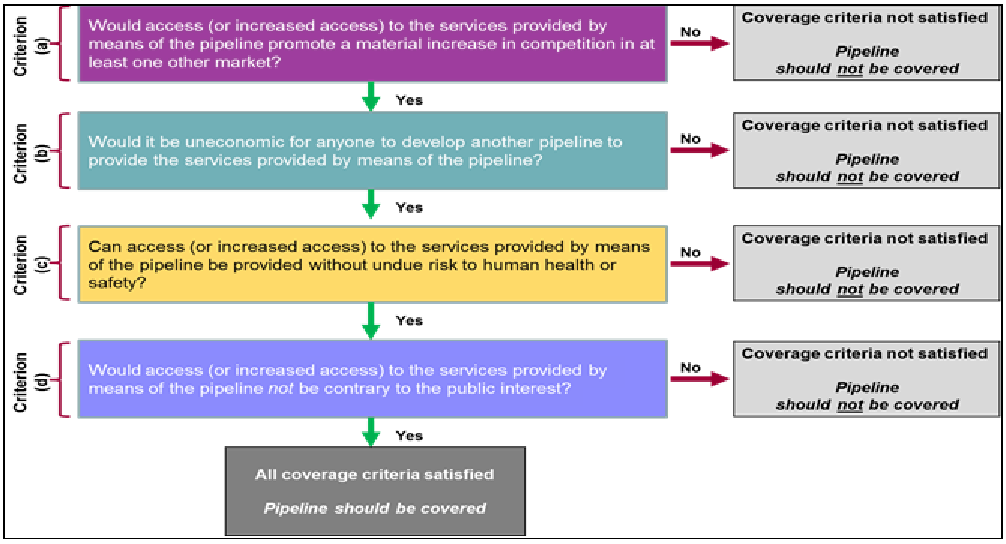
The NGL also provides for:

- coverage to be revoked if the relevant Minister finds that one or more of the coverage criteria are not satisfied; and
- a greenfields pipeline to become exempt from coverage for 15 years if the relevant Minister finds that one or more of the coverage criteria are not satisfied.

The remainder of this section provides further detail on the matters that the relevant Minister must consider when making a coverage, revocation of coverage or 15 year no-coverage decision.

It is worth noting that the NGL allows the coverage status of a pipeline and the form of regulation to change over time, because policy makers have recognised that circumstances can change over time.

Figure D.1 Coverage Criteria



D.3.1 Coverage and revocation of coverage decisions

An application for a coverage (or a revocation of coverage) determination can be made by any person to the NCC under section 92 of the NGL (or section 102 for revocation of coverage applications). Once such an application is received, the NCC is required to assess the application and make a recommendation to the relevant Minister.[481] In making its recommendation, the NCC is required to give effect to the following criteria set out in section 15 of the NGL:

- access (or increased access) to the services provided by means of the pipeline would promote a material increase in competition in at least one other market (criterion (a));
- it would be uneconomic to develop another pipeline to provide the services provided by means of the pipeline (criterion (b));
- access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety (criterion (c)); and
- access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest (criterion (d)).

In deciding whether or not these coverage criteria are satisfied, the NCC is required to have regard to the NGO.[482]

The decision-making framework in section 97(2) (or section 105(2) for revocation of coverage applications) of the NGL requires the NCC to recommend:

- coverage (or the continuation of coverage) if it is satisfied **all** the criteria are met; and
- against coverage (or the revocation of coverage) if it finds that one or more of the criteria is not satisfied.

A decision as to whether a pipeline should be covered (or coverage revoked) must ultimately be made by the relevant Minister having regard to the coverage criteria, the NGO, the NCC's recommendation and any submissions it receives. Like the NCC, the Minister can only determine the pipeline be covered if it is satisfied that **all** the coverage criteria are met.

With the exception of criterion (c), the coverage criteria in the NGL largely mirror the declaration criteria in sections Part IIIA of the CCA. The manner in which the declaration criteria have been interpreted by the NCC, the Tribunal, Federal Court and High Court have therefore had a strong influence on the way in which the coverage criteria have been applied in gas. Further detail on how the coverage criteria and equivalent criteria in Part IIIA of the CCA have been interpreted and applied by these bodies is provided in Box D.4.

481 The identity of the 'relevant Minister' will depend on whether the pipeline is a transmission or distribution pipeline and if the pipeline crosses jurisdictions. For example, if the pipeline is a cross boundary transmission pipeline, the relevant Minister is the Commonwealth Minister but if the transmission pipeline is situated wholly within a jurisdiction, the relevant Minister will typically be the State or Territory Minister (the one exception is Queensland where the relevant Minister is the Commonwealth Minister). See definitions section of NGL.

482 Sections 97 and 105 of the NGL.

Box D.4 Interpretation of coverage and declaration criteria

Criterion (a)

Criterion (a) requires consideration to be given to whether access (or increased access) to services provided by means of the pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the pipeline. The application of this criterion has been described by the NCC and Tribunal as involving the following two stage assessment process:[483]

Stage 1: Identify economically separable dependent (upstream or downstream) markets; and

Stage 2: Assess whether access[484] (or increased access) is likely to promote a material increase in competition in the dependent market(s) identified in Stage 1.

In *Sydney Airport Corporation Limited v Australian Competition Tribunal* [2006], the Full Federal Court held that the second stage of this assessment process requires consideration to be given to whether the future state of competition in a dependent market(s) "with access" is likely to differ materially from the future state of competition "without access."[485] Whether or not competition in a dependent market is likely to be materially different in these two states of the world will depend on a range of factors, including:

- the current state of competition in the dependent market(s), for example:
  - if the upstream or downstream market is already effectively competitive then access will not promote a material increase in competition in that market;[486] and
  - if there are other barriers to entry (unrelated to access) to the upstream or downstream market and these are prohibitive, then access is unlikely to promote a material increase in competition.[487]
- the ability and incentive the service provider has to exercise market power to adversely affect competition in the dependent market(s), by engaging in the following conduct:
  - preventing or hindering access;

483 NCC, Gas Guide – A guide to the functions and powers of the National Competition Council under the National Gas Law (Gas Guide), October 2013, pp. 28-39.

484 The term "access" has been defined by the NCC, in its Gas Guide as a "regulated right" to access the relevant services, rather than access that may be available under individual commercial arrangements.

485 *Sydney Airport Corporation Limited v Australian Competition Tribunal* [2006] FCAFC 146 [83].

486 *In the matter of Fortescue Metals Group Limited* [2010] ACompT 2 NCC, Gas Guide, October 2013, p. 34.

487 NCC, Final Recommendation – Application for the revocation of coverage of the GGP under the National Gas Access Regime, November 2003, p. 98.

— raising prices above what would prevail in an effectively competitive market;

— restricting throughput; and/or

— reducing service quality.

If it is established that a service provider has no incentive and/or ability to exercise market power in the dependent markets, then access is unlikely to promote a material increase in competition.[488]

Some insight into the importance the NCC and the Tribunal have placed on the latter of these matters can be seen in the extracts below:

NCC Gas Guide[489]

> "The ability and incentive for a service provider to exercise market power to adversely affect competition in a dependent market is a necessary (although not sufficient) condition for access to promote competition. Prima facie, regulation of the terms and conditions of the provision of the service by the service provider in these circumstances is likely to promote competition.
>
> In addition, a finding that the service provider has the ability and incentive to exercise market power to adversely affect competition in a dependent market is likely to mean that the barriers to entry in that market result from the natural monopoly characteristics of the facility and its bottleneck position. In the usual case, this finding would mean that access would reduce barriers to entry and promote competition in that dependent market.
>
> By contrast, the service provider may not have the ability or incentive to exercise market power to adversely affect competition in the dependent market(s) where:
>
> (a) the facility does not occupy a bottleneck position in the supply chain for the service
>
> (b) the service provider is constrained from exercising market power in the dependent market(s), perhaps by competitive conditions in the dependent market(s) and/or the market power of other participants in the market(s), or
>
> (c) the incentives faced by the service provider are such that its optimal strategy is to maximise competition in the dependent market(s). It may be profit maximising, for example, for a service provider to promote increased competition in the dependent market(s) and maximise demand for the services provided by its facility.

488 NCC, *Gas Guide*, October 2013, p .35.

489 NCC, *Gas Guide*, October 2013, p. 36.

Access is unlikely to materially promote competition in the dependent market(s) if the service provider does not have the ability and incentive to exercise market power to adversely affect competition in the dependent market(s)."

Tribunal in *Re Duke Eastern Gas Pipeline Pty Ltd [2001]* ACompT2 [116-124]

"Whether competition will be promoted by coverage is critically dependent on whether EGP has power in the market for gas transmission which could be used to adversely affect competition in the upstream or downstream markets. There is no simple formula or mechanism for determining whether a market participant will have sufficient power to hinder competition. What is required is consideration of industry and market structure followed by a judgment on their effects on the promotion of competition.

There are strong commercial incentives for Duke to increase the throughput of the EGP, given its high capital cost, low operating costs and spare capacity. There are three pipelines which can supply gas to the market in Sydney, although lesser numbers to the ACT and other places in NSW. The three pipeline operators all stated that it was in their own financial interests to increase market share, and that this may involve undercutting the prices of other pipelines where that was financially justified. Gas producers have significant power in dealing with pipeline operators, as does AGL as the major gas purchaser in the Sydney and Canberra markets. There are alternatives to the use of the EGP for producers and for purchasers of gas which provide a countervailing influence on any attempted exertion of market power by EGP in the transport market. For example, in the case of the Gippsland Basin, gas can be transported to Sydney via the Interconnect or sold into the Victorian market, and in the case of purchasers of gas in Sydney, the Interconnect or the Cooper Basin/MSP can be used as alternatives to the EGP.

The existence of spare pipeline capacity over the next 10 to 15 years is a further factor which militates against EGP being able to exert market power to the detriment of competition in the upstream or downstream markets. If transmission prices were increased above competitive levels by EGP, the spare capacity could be used to defeat a price rise, particularly in the first half of the decade when the MSP and the Interconnect could supply all of the forecast increase in NSW/ACT demand with increases in pipeline capacity at relatively low cost. If there were constraints on gas supplies from Moomba, then the spare pipeline capacity may be ineffective in restraining EGP from increasing prices, but we have already concluded that this is not likely over the next 10 to 15 years.

...

The Tribunal concludes that EGP will not have sufficient market power to hinder competition based on the commercial imperatives it

> faces, the countervailing power of other market participants, the existence of spare pipeline capacity and the competition it faces from the MSP and the Interconnect. As EGP does not have market power, the Tribunal cannot be satisfied that coverage would promote competition in either the upstream or downstream markets."

Criterion (b)

Criterion (b) requires consideration to be given to whether it would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline.

In 2012, the High Court in *Pilbara Infrastructure Pty Ltd v Australian Competition Tribunal*[490] held that the test to apply in considering whether it was uneconomic to duplicate particular infrastructure is a "privately profitable test" and that the term "uneconomic" should be interpreted as "unprofitable". The High Court went on to note the profitability of developing another facility will depend on whether a "person could reasonably expect to obtain a sufficient return on capital that would be employed in developing the facility". It also observed that if someone could develop an alternative facility as part of a larger project (e.g. as part of a mining project), "it would be necessary to consider the whole project in deciding whether the development of the alternative facility…would provide a sufficient rate of return".

The High Court's decision in this case overturned previous interpretations of this criterion, which had focused on whether the infrastructure exhibited natural monopoly characteristics. The practical effect of this interpretation is that if it can be established that it would be privately profitable for existing or future possible market participants to duplicate the asset, then criterion (b) would not be satisfied, even though duplication of the asset may not be economically efficient.

Although the High Court's decision related to Part IIIA of the CCA, it has been applied by the NCC when considering coverage decisions in gas. For pipelines that are used by mining companies or other shippers that generate substantial profits, the High Court's interpretation has, in effect, raised the threshold for this criterion to be satisfied and, in so doing, made it more difficult for these pipelines to become covered.

Criterion (c)

Criterion (c) requires consideration to be given as to whether access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety. When applying this criterion, the NCC has stated it will generally presume that provisions within the regulatory regime will provide "effective mechanisms to preserve human health and safety."[491]

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490 Pilbara Infrastructure Case (2012) 246 CLR 379, 413, [83 and 104].

491 NCC, Gas Guide, October 2013, p. 46.

Criterion (d)

Criterion (d) requires consideration to be given to whether access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest.

In the Pilbara Infrastructure Case, the High Court found the matters the NCC and Minister may have regard to is "very wide indeed" and may include consideration of "matters of broad judgment of a generally political kind" as distinct from the other criteria, which are of a "more technical kind."[492]

Following this decision, the NCC has stated that its role under criterion (d) is not to conduct a detailed examination of the costs and benefits of access to be undertaken. Rather, its task is to "identify any matter that could mean access (or increased access) might be contrary to the public interest and then assess whether the likelihood and consequences of that matter lead to a conclusion that access is contrary to the public interest."[493] Elaborating further on this, NCC has noted the following:[494]

> "This criterion does not allow for coverage of a pipeline on 'public interest grounds' when any other coverage criterion is not satisfied; it can only operate to override coverage being available in situations where all other coverage criteria are satisfied."

D.3.2 15 year no-coverage decisions

Under section 151 of the NGL, a service provider of a greenfield pipeline that is yet to be commissioned can apply to the NCC for a determination that exempts the pipeline from coverage for 15 years.

In a similar manner to the coverage provisions, the NCC is required to assess an application for a 15 year no-coverage decision having regard to the coverage criteria and the NGO and to make a recommendation to the relevant Minister.[495] If the NCC is satisfied that all the coverage criteria are met, the recommendation must be against a 15 year no-coverage decision. If, on the other hand, one or more criteria are not satisfied, the NCC's recommendation must be in favour of a 15 year no-coverage decision.[496]

Once the Minister has received the NCC's recommendation, it must decide itself whether to make a 15 year no-coverage determination, having regard to the coverage criteria, the NGO, the NCC's recommendation and any submissions it receives. Like the NCC, the Minister can only grant a 15 year no-coverage determination if it is satisfied that one or more coverage criteria are **not** met.[497]

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492 Pilbara Infrastructure Case (2012) 246 CLR 379, 413, [42 and 44].

493 NCC, Gas Guide, October 2013, p. 48.

494 NCC, Final Recommendation – Application for the revocation of coverage of the Wagga Wagga Distribution Network, 8 August 2013, p. 25.

495 Section 154 of the NGL.

496 Section 154(2) of the NGL.

497 Section 157 of the NGL.

D.3.3 Coverage related decisions

Table D.1 provides a summary of the key findings from some of the more significant coverage decisions that have been made over the last 15 years. As this table highlights, the decision as to whether a pipeline should be covered will depend on the specific facts surrounding the pipeline, its users and the markets it is used to supply, which, as the Dawson Valley Pipeline (DVP) example highlights, can change over time.

Some other interesting points to note from this table about the application of the coverage criteria are set out below:

- Criterion (a): In all but one of the cases where coverage has been revoked or a 15 year no-coverage determination has been granted, criterion (a) has **not** been satisfied;
- Criterion (b): Prior to the High Court's decision in the Pilbara Infrastructure case, this criterion was found to be satisfied in **all** determinations, but in the wake of this decision, the NCC and Commonwealth Minister have found it would be privately profitable to duplicate a number of pipelines (ie the LNG pipelines and DVP);
- Criterion (c): This criterion has been satisfied in all cases;
- Criterion (d): This criterion has been found to be satisfied in some cases but not in others. In most cases the finding on criterion (d) has been linked to the finding on criterion (a) (ie, if there are no competition related benefits then the costs of coverage are likely to outweigh the benefits, which is contrary to the public interest).

Another important point to note from this table is that while it has been suggested that the Tribunal's decision not to cover the Eastern Gas Pipeline (EGP) resulted in access regulation being removed on other pipelines, the reasons cited by Tribunal in this case have not been repeated in any other coverage or revocation of coverage decisions. Each decision has instead been made by the relevant Minister on its merits having regard to the specific circumstances surrounding that pipeline. The fact that coverage has been revoked on so many pipelines reflects a more general trend under Part IIIA of the CCA for declaration (equivalent to coverage) to be used in a sparing manner. The reason for this is explored in further detail in the following section.

Table D.1 Findings in significant coverage, revocation of coverage and 15 year no-coverage determinations in eastern Australia

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria	
Eastern Gas Pipeline	2001	Tribunal (the Duke Decision)	Not to cover	Criterion (a) **not** satisfied.	Criteria (b)-(d) satisfied.
				Both the Minister and NCC were of the view that the EGP, which had recently been constructed should be covered. The Tribunal, on the other hand, found that criterion (a) was not satisfied because as a new entrant the EGP did not have sufficient market power to hinder competition in an upstream or downstream market and had a strong incentive to encourage use of the pipeline.	
Moomba to Sydney Pipeline	2003	Commonwealth Minister	Revoke coverage between Moomba and Marsden (72 per cent of pipeline length), retain coverage on remainder.	From Moomba to Marsden criterion (b) **not** satisfied, but all other criteria satisfied.	From Marsden to Sydney criteria (a)-(d) satisfied.
				The Minister did not follow the NCC's recommendation, which was to retain coverage. The Minister instead found that criterion (b) was not satisfied between Moomba and Marsden and that coverage should be revoked on this part of the pipeline.	
Moomba to Adelaide Pipeline System	2007	SA Minister	Revoke coverage	Criteria (a) and (d) **not** satisfied.	Criteria (b) and (c) satisfied.
				The NCC and Minister found that criterion (a) was not satisfied because access was unlikely to promote competition in any of the identified markets (ie, the upstream production market, the Adelaide gas sales market or the market for gas sales north of Adelaide). The NCC and Minster were also not satisfied that the overall benefit of regulated access would outweigh the costs and therefore found that criterion (d) was not satisfied.	

<table>
<tr><th>Pipeline</th><th>Year of Decision</th><th>Decision Maker</th><th>Decision</th><th colspan="2">Findings on Coverage Criteria</th></tr>
<tr><td rowspan="2">QCLNG</td><td rowspan="2">2010</td><td rowspan="2">Commonwealth Minister</td><td rowspan="2">15 year no-coverage determination</td><td>Criteria (a) and (d) not satisfied.</td><td>Criterion (b) and (c) satisfied.</td></tr>
<tr><td colspan="2">The NCC and Minister found that access would not promote a material increase in competition in: the downstream LNG market because it was already competitive; the upstream gas production market because producers in the area could access other pipelines; or downstream gas sales markets in the Gladstone, Rockhampton and Wide Bay areas because users in this area have other supply options. Criterion (a) was therefore found not to be satisfied. In relation to criterion (d), the NCC noted that because access would not promote a material increase in competition in any market the costs of coverage were likely to outweigh the benefits and therefore be contrary to the public interest.</td></tr>
<tr><td rowspan="2">APLNG</td><td rowspan="2">2012</td><td rowspan="2">Commonwealth Minister</td><td rowspan="2">15 year no-coverage determination</td><td>Criteria (a), (b) and (d) not satisfied.</td><td>Criterion (c) satisfied.</td></tr>
<tr><td colspan="2">The NCC and Minister’s reasons for finding that criteria (a) and (d) were not satisfied were essentially the same as those cited in the QCLNG case. Criterion (b) was also found not to be satisfied in this case. In forming this view, the NCC and Minister pointed to the fact that there were three LNG pipelines being developed in the region and noted that this indicated it was economically feasible to develop an alternative pipeline. Note that the decision on criterion (b) followed the High Court’s decision on this criterion.</td></tr>
<tr><td rowspan="2">GLNG</td><td rowspan="2">2013</td><td rowspan="2">Commonwealth Minister</td><td rowspan="2">15 year no-coverage determination</td><td>Criteria (a), (b) and (d) not satisfied</td><td>Criterion (c) satisfied.</td></tr>
<tr><td colspan="2">The NCC’s and Minister’s reasoning in this case is essentially the same as it was in the APLNG case.</td></tr>
</table>

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria	
South East Pipeline System	2013	SA Minister	Not to cover	Criteria (a) and (d) **not** satisfied	Criterion (b) and (c) satisfied.
				The NCC and Minister were not satisfied that access would promote a material increase in competition in any of the dependent markets identified (the Australian and global markets for paper tissue products, upstream gas supply/production in the Katnook area and other shippers delivering gas to Katnook via the SEA Gas and SESA pipelines, a downstream market for industrial, commercial and domestic purposes in the South East region of SA). In relation to criterion (d), the NCC noted that because access would not promote a material increase in competition in any market the costs of coverage were likely to outweigh the benefits and therefore be contrary to the public interest.	
Wagga Wagga Distribution System	2014	NSW Minister	Revoke coverage	Criterion (a) **not** satisfied if retail price regulation retained	Criterion (b), (c) and (d) satisfied
				The NCC found that access would not promote a material increase in competition in the eastern Australian wholesale gas market or the market for transmission services, but that it may promote a material increase in competition in the downstream gas sales market if retail price regulation was removed (note that the NCC found that limited competition had emerged in the downstream gas sales market because of the presence of retail price regulation, which was limiting available margins). The NCC went on to note however that if retail price regulation was not removed, then competition in this market was likely to remain stagnant irrespective of whether the pipeline was covered or not and criterion (a) was unlikely therefore to be satisfied under this scenario. Following a decision by the NSW Government in early 2014 not to remove retail price regulation on gas sales to small customers, the NSW Minister concluded that criterion (a) was not satisfied and that coverage should be revoked.	

Pipeline	Year of Decision	Decision Maker	Decision	Findings on Coverage Criteria	
Dawson Valley Pipeline (DVP)	2014	Commonwealth Minister	Revoke coverage	Criteria (a) and (b) **not** satisfied.	Criteria (c) and (d) satisfied
				The NCC and Minister found that: • Criterion (a) was not satisfied because there would only be a small amount of capacity available to third parties from 2015, so access would not promote a material increase in competition in any market. • Criterion (b) was not satisfied because there was evidence that one of the users of the pipeline was intending to develop its own pipeline to supply its plant. This was the fourth time that the coverage status of the DVP has changed over the last 17 years, ie: • the DVP was originally identified as a covered pipeline in Schedule A of the Gas Code; • in mid-2000 coverage was revoked because criterion (a) was found not to be satisfied; and • in 2006 coverage was reinstated because all the coverage criteria were found to be satisfied.	

D.3.4 Recent reviews of Part IIIA and potential implications for the coverage criteria

Following the High Court's decision in the Pilbara Infrastructure case a number of parties questioned whether the declaration criteria in Part IIIA, and by extension the coverage criteria in the NGL, were operating as they were intended to.

This question was considered in some detail by the Productivity Commission in its 2013 review of the National Access Regime. In short, the Productivity Commission found that while the declaration has been rare, this was consistent with Hilmer Committee's intention that the regime be used sparingly. The Productivity Commission went on to note that the rarity of declaration did not mean the regime had been unsuccessful, because it could be the case that:[498]

> "...parties are resolving access disputes without recourse to Part IIIA, or that Part IIIA is an effective threat that encourages parties to reach private settlement."

Some of the other key findings and observations from this review are outlined below:

- The National Access Regime should be retained and used to address "an enduring lack of effective competition, due to natural monopoly, in markets for infrastructure services where access is required for third parties to compete effectively in dependent markets" and the service provider has an ability and incentive to exercise market power. The Productivity Commission went on to note that this is the only economic problem that access regulation should address and that it should not be viewed as a vehicle to avoid the duplication of infrastructure, or wider social and economic issues;[499]
- The scope of the National Access Regime should be "confined to ensure its use is limited to the exceptional cases where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third party access to infrastructure services;"[500]
- Competition between service providers will generally be preferable to access regulation where two or more service providers are able to provide the same service (or an effective substitute service). Even if an infrastructure service provider has a monopoly position in a particular market, its market power might be constrained by the existence of substitutes, countervailing market power or the threat of entry;[501]
- The declaration criteria should be amended in the following ways to ensure that they target the relevant economic problem;[502]

498 Productivity Commission, *National Access Regime*, 25 October 2013, p. 14.

499 Productivity Commission, *National Access Regime*, 25 October 2013, p. 2.

500 Productivity Commission, *National Access Regime*, 25 October 2013, p. 2.

501 Productivity Commission, *National Access Regime*, 25 October 2013, p. 8.

502 Productivity Commission, *National Access Regime*, 25 October 2013, pp. 16-20.

— Criterion (a) should be amended so that it will only be satisfied where access on reasonable terms and conditions through *declaration* (rather than access per se) would promote a material increase in competition in a dependent market;[503]

— Criterion (b) should be amended so that it can be used to identify facilities that give rise to an enduring lack of effective competition.

— Criterion (f) (or criterion (d) in the coverage criteria) should be amended so that the test is expressed in the affirmative (ie access would need to promote the public interest rather than being "not contrary to" the public interest).

The Productivity Commission's observation that the third-party access regime should be confined to exceptional cases was endorsed by the Competition Policy Review Panel as highlighted in the following extract:[504]

> "The bottleneck infrastructure identified by the Hilmer Review included electricity wires, gas pipelines, telecommunication lines, freight rail networks, airports and ports. Distinct access regimes have emerged for these different types of infrastructure, reflecting their distinct physical, technical and economic characteristics. Those regimes appear to be achieving the original policy goals identified by the Hilmer Review. Part IIIA has played an important role in developing these access regimes.
>
> ...
>
> Part IIIA should continue to provide a back stop to the current industry-specific access regimes...
>
> The Panel agrees with the conclusion of the recent PC inquiry that the National Access Regime is likely to generate net benefits to the community, but its scope should be confined to ensure its use is limited to the exceptional cases where the benefits arising from increased competition in dependent markets are likely to outweigh the costs of regulated third-party access."

The Competition Policy Review Panel also suggested that the declaration criteria be amended as follows:[505]

- Criterion (a) should require that access on reasonable terms and conditions through declaration promote a substantial increase in competition in a dependent

503 The Productivity Commission noted that this criterion would not be satisfied where: there is already effective competition in dependent markets (ie, because it would not promote a material increase in competition in this market; or access is already granted to all third parties on reasonable terms and conditions (ie, because declaration would not be expected to change the terms and conditions of access).

504 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review Final Report*, March 2015, p. 431.

505 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review Final Report*, March 2015, p. 74.

market that is nationally significant. Elaborating further on this proposed change, the Panel stated:[506]

> "The burdens of access regulation should not be imposed on the operations of a facility unless access is expected to produce efficiency gains from competition that are significant. This requires that competition be increased in a market that is significant and that the increase in competition be substantial."

- Criterion (b) should require that it be uneconomic for anyone (other than the service provider) to develop another facility to provide the service. The Panel in this case endorsed the use of the privately profitable test adopted by the High Court.
- Criterion (f) should require that access on reasonable terms and conditions through declaration promote the public interest.

The Competition Policy Review Panel also made the following observations about the circumstances in which access regulation should be applied:[507]

> "The Regime facilitates intrusive economic regulation of infrastructure assets. It overrides private property rights, mandating that the operator of an infrastructure facility make that facility available for use by a third-party on terms and conditions (including price) determined by a regulatory body (the ACCC). By that process, the economic return that the operator of the facility is able to earn on its investment in the facility will be subject to regulation.
>
> Economic regulation of privately owned assets is likely to impose costs on the economy. In recommending the introduction of the Regime, the Hilmer Review was conscious of the economic costs that might be imposed:
>
> *The Committee is conscious of the need to carefully limit the circumstances in which one business is required by law to make its facilities available to another. Failure to provide appropriate protection to the owners of such facilities has the potential to undermine incentives for investment. Nevertheless, there are some industries where there is a strong public interest in ensuring that effective competition can take place ...*
>
> The Productivity Commission also noted the costs that are created by economic regulation:
>
> *Access regulation also imposes costs, in particular where it adversely affects incentives for investment in markets for infrastructure services. There are costs associated with errors in setting access prices. For example, when prices are set too low, this can lead to delayed investment in infrastructure, or the non-provision of some infrastructure services.*

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506 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., *Competition Policy Review Final Report*, March 2015, p. 73.

507 Harper, I., Anderson, P., McCluskey, S. and O'Bryan, M., Competition Policy Review, Draft Report, September 2014, pp. 264-265.

> Regulated third party access can also impose costs on infrastructure service providers from coordinating multiple users of their facilities.
>
> Given the economic costs that are likely to be caused by this form of regulation, it is important to examine carefully the benefits of the Regime and to ask whether those benefits can be achieved by a less intrusive form of regulation."

The findings of both the Productivity Commission and the Competition Policy Review Panel suggest that while some amendments may be made to the coverage criteria to bring them into line with any changes that are made to the declaration criteria, the threshold for coverage will still be high (if not higher if criterion (a) is amended to require a substantial increase in competition) and will continue to be applied in a sparing manner.

D.4 Alternative forms of regulation under the NGL and NGR

A covered pipeline may be subject to either full or light regulation, depending on the degree of market power it possesses. The circumstances in which policy makers expected light regulation to be applied can be found in the following extract taken from the Second Reading Speech:[508]

> "Determining how covered pipeline services are to be regulated requires an assessment of the potential for market power to be exploited by a service provider. …where light regulation can reduce the costs of regulation while still providing an effective check on a pipeline's market power, the light regulation option should be available..."

Further insight into the circumstances in which light regulation is intended to apply can be found in the following extract taken from the NCC's Light Regulation Guide:[509]

> "The intention in introducing this lighter form of regulation is that, through its use in appropriate circumstances, the administrative costs to the pipeline services provider and the regulator will be lower. This less intrusive form of regulation is considered to be appropriate where the market power exercised by the provider is less substantial and there is the potential for contestability for the services to emerge. It may also be appropriate where the number of access seekers is relatively small and these parties can themselves exercise some countervailing market power in the course of commercial negotiations. Further, light regulation may be an appropriate option for regulation where particular assets are in a transition towards effective competition."

A snapshot of the obligations that service providers of full and light regulation pipelines are subject to under the NGL and NGR is provided in the table below. This

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508 South Australian Hansard 2008, '*National Gas (South Australia) Bill 2008*', Legislative Assembly, p. 2701, 9 April 2008.

509 NCC, Light regulation of covered pipeline services – A guide to the function and powers of the NCC under the NGL Part C, July 2011, p. 14.

table also sets out the obligations that unregulated pipelines are subject to under the NGL and NGR.

Table D.2 Economic regulatory and information obligations for full, light and unregulated pipelines

		Full Regulation	Light Regulation	Unregulated
Application of the Economic Regulatory Provisions in the NGR and NGL				
Obligation for pipeline service provider to:	• obtain AER approval for proposed reference tariffs and other conditions of access[510]	✓	×	×
	• publish prices and other terms and conditions of access[511]	Access arrangement must be made available	Must be published on the service provider's website	×
	• report to the AER on the status of access negotiations[512]	×	✓	×
	• comply with facilitation of, and request for, access rules[513]	✓	✓	×
	• not engage in price discrimination unless it is efficient to do so	×	✓	×
	• comply with other NGL provisions that are designed to prevent service providers from engaging in conduct that may adversely affect 3rd party access or competition.[514]	✓	✓	×
Access to dispute resolution mechanism in NGL[515]		✓	✓	×
Bulletin Board and STTM Provisions in the NGR and NGL				
Obligation to provide AEMO with information for the BB[516]		Yes if the service provider is designated by AEMO as a BB facility operator.		
Obligation to provide AEMO with any information it requires for the operation and administration of a STTM.[517]		✓	✓	✓

510 Rule 48 of the NGR.

511 Rule 36 of the NGR for light regulation and rule 44 for full regulation.

512 Rule 37 of the NGR.

513 Part 11 of the NGR.

514 Section 133 of the NGL.

515 Chapter 6, Part 1 of the NGL and Part 12 of the NGR.

516 Section 223 of the NGL.

Further detail on these obligations is provided below, along with an overview of the matters the NCC is required to consider when making a decision on the form of regulation is provided below.

D.4.1 Full regulation

The service provider of a pipeline that is subject to full regulation is required by the NGR to periodically submit a “full access arrangement” (AA) to the AER (or the Economic Regulatory Authority (ERA) in Western Australia) and obtain its approval for the proposed terms and conditions of access to the reference service(s). In accordance with rule 48 of the NGR, the full AA must set out:

- the reference service(s) to be provided by the pipeline and the reference tariff payable for each reference service (a “reference service” is defined in the NGR as a service that is likely to be sought by a significant portion of the market);
- the terms and conditions upon which the reference service(s) will be provided; and
- the pipeline’s queuing policy,[518] capacity trading policy,[519] extensions and expansions policy[520] and the terms on which receipt/delivery points may be changed by the shipper.

When assessing a proposed access arrangement, the AER is required to have regard to:

- the price and revenue regulation related provisions set out in Part 9 of the NGR;
- the national gas objective (NGO) set out in section 23 of the NGL; and
- the revenue and pricing principles set out in section 24 of the NGL.

To ensure that users (existing or prospective users) have some degree of protection if they decide to negotiate access to an alternative service or different terms and conditions (including tariffs), provision has been made in the NGL for a user or a service provider to trigger the dispute resolution mechanism if a dispute about access

517 Section 91FEA of the NGL.

518 This policy is used to determine the order of priority for access to spare and developable capacity.

519 The capacity trading policy must enable users to transfer capacity and comply with the following: a user may transfer any portion of its contracted capacity to a third party through a sub-contractual arrangement without the service provider’s consent but must inform the service provider of the sub-contract and the likely duration, the identity of the third party and the amount of capacity transferred; and a user may transfer any portion of its contracted capacity to a third party with the service provider’s consent. The service provider must not withhold consent unless it has reasonable grounds for doing so.

520 The extensions and expansions policy must set out whether the applicable access arrangement will apply to incremental services to be provided as a result of a particular extension to, or expansion of, the pipeline or may allow for later resolution of that question on a basis stated in the requirements.

arises.[521] The dispute resolution body in eastern Australia and the Northern Territory is the AER, while in WA it is the ERA.[522]

Some other important safeguards that have been included in the NGL and NGR to facilitate access and to prevent service providers from engaging in conduct that may adversely affect third party access or competition in upstream or downstream markets include:

- The facilitation of, and request for, access rules set out in Part 11 of the NGR. Amongst other things, these provisions require service providers to:
  - make available information that a prospective user reasonably requires to decide whether to seek access to a pipeline service; and
  - respond to any access request made by a prospective user within a defined period and provide information on the tariff that would apply, if it is commercially and technically feasible to provide the service.
- Section 133 of the NGL, which states that a service provider must not engage in conduct that prevents or hinders a person's access to the services provided by the pipeline.
- Sections 137-148, which set out the ring-fencing requirements that a service provider must comply with and are designed to prevent a service provider from:
  - carrying on a related business (ie production, purchase or sale of natural gas); and
  - conferring an unfair advantage on an associate that takes part in a related business.

These safeguards apply equally to pipelines that are subject to full and light regulation.

D.4.2 Light regulation

In contrast to full regulation, light regulation places greater emphasis on commercial negotiation and information disclosure. Users and prospective users are also provided with some degree of protection in these negotiations through the following safeguards:

- the dispute resolution mechanism in Chapter 6 of the NGL and Chapter 12 of the NGR;
- section 136 of the NGL, which prohibits a service provider of light regulation services from engaging in price discrimination, unless it is efficient to do so; and
- sections 133 and 137-148 of the NGL, which are designed to prevent service providers from engaging in conduct that may adversely affect third party access or competition in other markets.

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521 If such a dispute arises, the prospective user or service provider may notify the dispute resolution body in writing. The dispute resolution body may then require the parties to mediate, conciliate or engage in other alternative dispute resolution processes to resolve the dispute.

522 The dispute resolution mechanism has not yet been triggered on any light or full regulation pipelines.

Commercial negotiation and information disclosure are encouraged through a number of provisions in the NGR, which require a service provider to:

- publish the price and non-price terms and conditions of access to light regulation services on its website (rule 36);
- comply with the facilitation of, and request for, access rules (Part 11 of the NGR); and
- report to the AER on access negotiations (at least annually) and, in doing so, set out the results of the negotiations and provide any other information that the AER requires (rule 37).

The service provider of a light regulation pipeline also has the option under section 116 of the NGL to develop a "limited" AA for approval by the AER. The key difference between a limited and full AA is that the limited AA does not need to include reference tariffs.

The AER's (ERA's) role under this form of regulation is to monitor the progress of access negotiations and arbitrate any access disputes that may arise.

D.4.3 Unregulated pipelines

Unregulated pipelines are not subject to any form of economic regulation under the NGL or the NGR. Nor are they required by the NGL to provide access to third parties on fair and reasonable terms, or in a non-discriminatory manner. They may, however, still be required to provide AEMO with:

- certain information for publication on the Bulletin Board if they have been deemed a Bulletin Board facility operator;[523] and
- any information it requires for the operation and administration of a STTM, if it is in control of such information.[524] [525]

The obligation to provide this information has been established through the NGL. Provision has also been made in the NGR for the costs incurred in the provision of aggregation and information services to be invoiced to AEMO and for the AER to assess the reasonableness of these costs before the invoice is paid.[526]

523 Section 223 of the NGL.

524 Section 91FEA of the NGL

525 This obligation is more relevant to pipelines that are connected directly to a STTM.

526 Rules 197-198.

D.4.4 Form of regulation decisions by the NCC

For pipelines that are covered and are not "designated,"[527] an application may be made to the NCC seeking a change in the form of regulation to apply to that pipeline. Unlike a decision on coverage, which must be made by the relevant Minister, a decision as to whether full or light regulation should be applied can be made by the NCC.

In making such a decision, the NCC is required by section 122 of the NGL to have regard to:

(a) the likely effectiveness of full and light regulation in promoting access to the services provided by the pipeline that is the subject of the application; and

(b) the effect of full and light regulation on the costs that may be incurred by an efficient service provider, efficient users and prospective users, and end-users.

In doing so, the NCC is required to have regard to the NGO, the form of regulation factors in section 16 of the NGL and any other matters the NCC considers relevant.

In simple terms, the form of regulation factors require consideration to be given to the extent to which:

- the service provider is likely to possess market power, either as a result of barriers to entry or network externalities;
- any market power possessed by the service provider may be constrained by:
  - countervailing power held by users or prospective users; or
  - the ability of users or prospective users to switch to an alternative provider of pipeline services or another energy source; and
- users or prospective users will have access to adequate information to negotiate on an informed basis under light regulation.

527 A designated pipeline is a pipeline classified by the Regulations, or designated in the application Act of a participating jurisdiction, that cannot be subject to light regulation. The pipelines that are currently designated include AGNL's SA Distribution Network, ATCO's Western Australian gas distribution system, the three Victorian gas distribution systems and the DTS. See National Gas (South Australia) Regulations 2009, National Gas Access (WA) (Part 3) Regulations 2009, Schedule 1 and Victorian Government Gazette No. S222m, 30 June 2009.

E Operation of the STTM

This appendix provides a detailed overview of the STTM design and operation. It draws on AEMO's Industry Guide to the STTM v3.5 and sets out:

- history and policy objectives of the STTM;
- design and structure of the market;
- rule changes carried out by the AEMC to date; and
- current market participants at each of the STTM hubs.

E.1 History and policy objectives

The STTM was implemented in Adelaide and Sydney in September 2010 and in Brisbane in December 2011. It was part of a package of reforms by the Council of Australian Governments' (COAG) Ministerial Council on Energy (MCE), which also included the National Gas Bulletin Board, Gas Statement of Opportunities and the establishment of a national gas market operator.[528]

At its November 2005 meeting, the MCE agreed to an industry-led approach to gas market development and established the Gas Market Leaders Group. This group, which comprised members from all aspects of the natural gas supply chain, was required to further develop options identified in a 2005 report by the Allen Consulting Group prepared for the MCE.[529]

Recommendations put forward by the Gas Market Leaders Group were required to be consistent with the following MCE principles:[530]

- Information on market and system operations and capabilities at all stages of the gas supply chain (subject to recognition of existing contractual confidentialities) should be publicly available and frequently updated.
- Gas market structure should facilitate a competitive market in all sectors.
- Gas market participants should be able to freely trade between pipelines, regions and basins.
- There should be regulatory certainty and consistency across all jurisdictions.
- Market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

The Gas Market Leaders Group presented its report to the MCE for consideration in June 2006. Among other things, the group recommended that the "detailed design of a Short-Term Trading Market be progressed for all states, except Victoria."[531]

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528 The national gas market operator became AEMO who assumed the functions of the state-based Gas Market Company, Retail Energy Market Company and gas functions of the Victorian Energy Networks Corporation.

529 The Allen Consulting Group, *Options for the development of the Australian Wholesale Gas Market*, Final Report, June 2005.

530 Gas Market Leaders Group, *National Gas Market Development Plan – Gas Market Leaders Group report to the Ministerial Council on Energy*, June 2006, p. 1.

In recommending the establishment of the STTM, the Gas Market Leaders Group set out the following objectives for the market:[532]

- Establish a mandatory price-based balancing mechanism for gas delivered and withdrawn from defined market hubs, replacing existing gas balancing arrangements at delivery points within hubs.
- Facilitate gas trading on a daily basis at market driven short-term prices.
- Provide pricing signals and facilitate secondary trading between shippers and users, for gas-fired generators, for trading over interconnecting pipelines between hubs, and to facilitate greater demand side response.

STTM costs and benefits were assessed by consultants MMA on behalf of the Gas Market Leaders Group. In 2006, MMA estimated the set up costs for hubs in Sydney and Adelaide would be $9 million, with ongoing operating costs of around $1.6 million annually. The net benefit of the STTM over the first 10 years of operation was estimated at $31 million due to:[533]

- more efficient pricing: through transparency around the short term price of gas;
- value of short term trading: enabling mutually beneficial trading to occur more regularly;
- improved gas allocation during a shortfall: ensuring scarce gas is allocated to the highest value users;
- improved capacity utilisation: through more efficient investment in pipeline capacity; and
- other benefits: including improved risk management allocation, provision of additional investment signals and greater flexibility for gas-fired generators.

Since the inception of the STTM in 2010, the AEMC has considered 11 changes to the relevant NGR, all of which have been submitted by AEMO. A summary of these are set out in section E.3.

The following section provides an overview of the design and operation of the STTM, including number and type of participants.

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531 Gas Market Leaders Group, *National Gas Market Development Plan – Gas Market Leaders Group report to the Ministerial Council on Energy*, June 2006, p. 2.

532 Gas Market Leaders Group, *National Gas Market Development Plan – Gas Market Leaders Group report to the Ministerial Council on Energy*, June 2006, p. 23.

533 Gas Market Leaders Group, *National Gas Market Development Plan – Gas Market Leaders Group report to the Ministerial Council on Energy*, June 2006, pp. 38-39.

E.2 Design and structure of the STTM

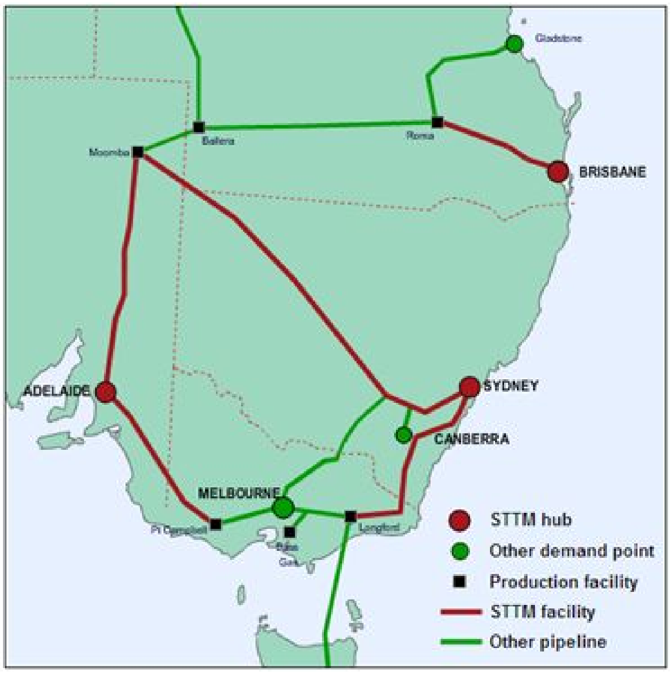
STTM hubs are day-ahead or ex ante markets for the trading at a wholesale level between facilities and distribution pipelines in Brisbane, Sydney and Adelaide.[534] They are used for:

1. providing a competitive service for participants to manage their daily gas imbalances; and
2. commodity trading.

Prior to the implementation of the STTM, commodity trading occurred bilaterally between participants and balancing was generally undertaken through contractual arrangements with pipeline operators or organised 'Swing Service' markets, such as what used to occur in Adelaide and under the current arrangements in south-west Western Australia.[535]

STTM hubs in Adelaide and Sydney are each supplied by two transmission pipelines, while the Brisbane STTM hub is supplied by one transmission pipeline, as shown in Figure E.1.

Figure E.1 STTM hubs are located at Adelaide, Brisbane and Sydney



Source: AEMO.

A range of participants, such as retailers, gas-fired generators and large industrial customers, use the STTM. All participants all use the market to physically sell or procure gas and there are no financial organisations registered. Section E.4 sets out the number and type of participants currently registered at each hub.

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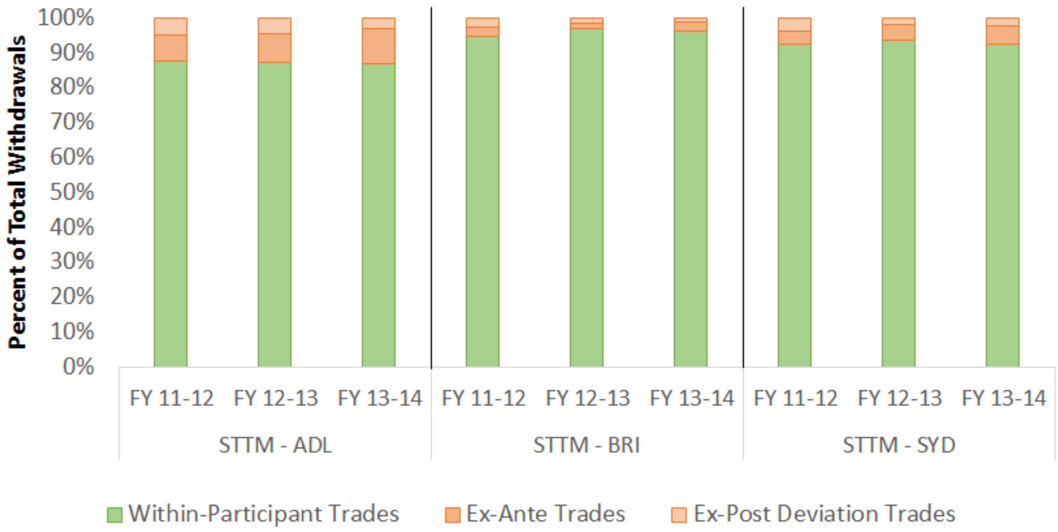
534 Ex ante refers to transactions that occur the day before a commodity is traded.

535 AEMO and REMCo, *Business case for a Short Term Trading Market in Western Australia*, available at: http://www.remco.net.au/attachments/article/60/WA%20STTM%20Assessment%20-%20Final%20%2826-06-13%29%20v6.pdf.

As the majority of gas bought and sold on the east coast is through long term bilateral contracts outside of the STTM, many participants are generally both shippers and users.[536] This is because all gas delivered to the hub is required to be transacted through the STTM, which results in an entity selling gas into the STTM and purchasing it back each day.

Figure E.2 categorises STTM transactions into three types: within-participant trades, ex ante trades and ex post deviation trades. The graph shows that at least 85 per cent of transactions across all STTM hubs are within-participant, while for Brisbane the number is over 95 per cent. Most ex ante trades have occurred in Adelaide, with the least occurring in Brisbane. A fee of $0.082/GJ of gas that is transacted through the hub is currently required to be paid to AEMO, irrespective of whether two related entities are trading between themselves.[537]

Figure E.2 Vast majority of STTM trades are within-participant



Source: AEMO data provided to the AEMC. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities at the start of the gas day; ex post deviation trades is deviations during the gas day.

Due to the physical characteristics of natural gas and the time it takes to flow through transmission pipelines, nominations by gas users are made to producers and pipeline operators a day ahead.[538] Accordingly, the STTM design consists of two broad elements:

- **the ex ante or commodity market** – where supply and demand is matched for the following day and an ex ante price determined by the market operator; and

536 STTM shippers deliver gas to be sold into the market and STTM users buy gas for consumption.

537 AEMO, *Consolidated Draft Budget and Fees: 2015-16*, March 2015, p. 15.

538 In Victoria, gas is typically produced and delivered within 6 – 8 hours due to the close proximity of the gas fields to demand centres. In contrast, gas delivered from the Cooper Basin into Sydney can take 2-3 days.

- **on-the-day balancing mechanism** – to account for differences during the gas day between the supply and demand schedules determined in the ex ante market and to ensure system security is maintained.[539]

Each of these elements is discussed below in sections E.2.2 and E.2.3. Before this, we briefly describe how the STTM design accounts for the contractual arrangements that underpin the contract carriage pipeline framework.

E.2.1 STTM overlay on the contract carriage pipeline framework

The underlying contractual arrangements between transmission pipeline operators and shippers, and between distribution networks and users, must be registered in the STTM with AEMO.[540] Preservation of these arrangements was a key design feature of the market and, while AEMO operates the market, it has no role in how transmission pipelines, storage facilities, production facilities or distribution networks are operated and scheduled.

Every bid to buy gas and every offer to sell gas through the STTM must be associated with a trading right. AEMO requires shippers and users to hold trading rights with sufficient pipeline capacity for the quantities of gas they are scheduled to flow.

When pipelines are scheduled, the terms of haulage contracts usually give shippers with firm gas haulage rights priority over shippers with lesser priority haulage rights, such as contracts with a non-firm or as-available capacity. However, the STTM scheduling process does not take account of these priorities when scheduling offers other than to resolve tied offer prices.[541]

If a pipeline's capacity is constrained, an as-available shipper can theoretically displace a firm capacity shipper in the STTM by offering gas at a lower price. This prevents the firm capacity shipper from using the pipeline capacity that it has funded.[542]

On a constrained pipeline, if an as-available shipper has been scheduled by the pipeline operator to flow gas to the hub, and, in doing so, has prevented a shipper with firm pipeline haulage rights from shipping gas on the same pipeline, then the as-available shipper pays a capacity charge based on the actual quantity of gas flowed.[543]

The firm-capacity shipper who is displaced on that pipeline receives a capacity payment based on the amount of gas it offered into the ex ante market but did not flow.

539 In this context, system security refers to transmission and distribution pipelines operating within their pressure tolerances.

540 The STTM design preserves the fundamental contract carriage arrangements on which the industry is based. Detail on the contract carriage arrangements can be found in chapter 4.

541 AEMO, *Industry Guide to the STTM*, December 2014, p. 27.

542 Ibid.

543 Ibid, 28.

E.2.2 Ex ante (commodity) market

The ex ante or commodity market is where shippers offer to supply gas and users bid to purchase gas that will flow the following day. Offers and bids can be submitted to AEMO up until 12.00pm the day before gas day in Adelaide and Sydney, and up until 1.30pm in Brisbane.[544]

Transactions in the ex ante market can be separated into two categories. The first and most common relates to the same entity selling and purchasing gas through the hub. As all gas that flows through the distribution network within the hub must be transacted in the STTM, participants with underlying long term contracts that do not need to trade at the hub on an ex ante basis must still participate. This generally results in a retailer offering gas into the STTM and bidding to withdraw the same amount.

In this instance, as a participant is on both sides of the transaction, there is no price risk in the ex ante market. For instance, if the retailer's underlying gas contract price is $3/GJ but the STTM clears at $7/GJ, the retailer will effectively be selling and buying the gas to itself at $7/GJ in the STTM. Price risks emerge through the on-the-day balancing mechanism if a retailer deviates from its ex ante schedules on the gas day, as discussed in section E.2.4.

The second category of transaction is where two different entities buy and sell gas in the ex ante market. A retailer who has expected demand at the hub of 100 TJ, but has an underlying gas contract for 80 TJ, will offer to supply 80 TJ in the ex ante market and bid to withdrawal 100 TJ. In this example, the retailer will be exposed to ex ante price risk on 20 TJ, which is the volume of gas not supplied through the long term contract.

STTM bids and offers can include up to 10 price-quantity steps. Offers to supply are given in increasing price order with increasing cumulative quantities. Bids to buy are given in decreasing price order with increasing cumulative quantities, as illustrated in Table E.1.[545]

Prices in the STTM must be within $0/GJ to $400/GJ, although users can submit price taker bids that represent a quantity of gas the user will accept at any price.[546] If the cumulative price over seven consecutive days reaches $440/GJ,[547] AEMO applies the administered price cap of $40/GJ for the whole of the gas day it is determined.[548] This mechanism is designed to protect participants from uncontrollable risks due to sustained high prices.

544 The variation in timing is due to differences in gas day start times at the hubs. The Brisbane hub operates from 8am EST while Sydney and Adelaide operate from 6.30am EST.

545 AEMO, *Industry Guide to the STTM*, December 2014, p. 30.

546 A price taker bid quantity is represented by a blank price cell in a price-quantity pair.

547 NGR, rule 364, CPT horizon.

548 NGR, rule 428(6)(a).

Table E.1 STTM offers and bids are in increasing and decreasing price order, respectively

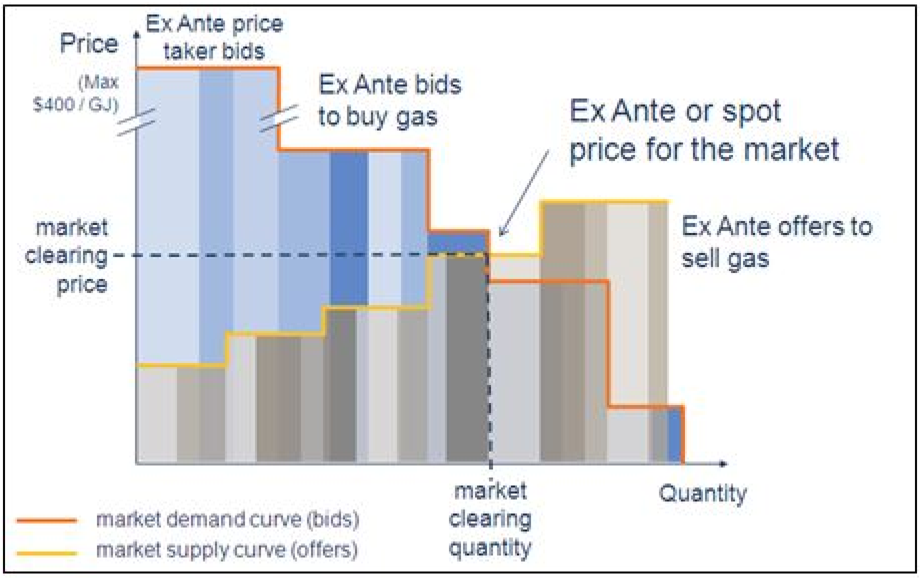
Price steps	Offers to ship gas to the hub		Bids to withdraw gas from the hub	
	Price ($)	**Quantity (GJ)**	**Price ($)**	**Quantity (GJ)**
1	0	5,000	[price taker]	10,000
2	1	20,000	8	1,000
3	1.5	10,000	5	5,000
4	2	5,000	3.5	2,000
5	3	20,000	1	1,000

Source: AEMC, based on AEMO STTM training material.

AEMO produces the market schedules and prices using an algorithm on the day before the gas day. The ex ante price is determined by stacking offers from lowest to highest price against bids to purchase gas from highest to lowest price, as shown in Figure E.3.

The point where demand intersects supply represents the marginal cost at which demand from all distribution systems is met by supply from shippers on STTM transmission pipelines and other hub facilities. All of the gas that flows in accordance with the ex ante market schedule on the gas day is settled at the ex ante price.

Figure E.3 The ex ante market price is set where demand meets supply



Source: AEMO, *An Overview of the Short-Term Trading Market (STTM)*, Section 4, p. 15.

In situations where bids (including price-taker withdrawals) or offers have the same price and the total quantity bid or offered cannot be scheduled, then tie-breaking rules are applied to determine the schedule.

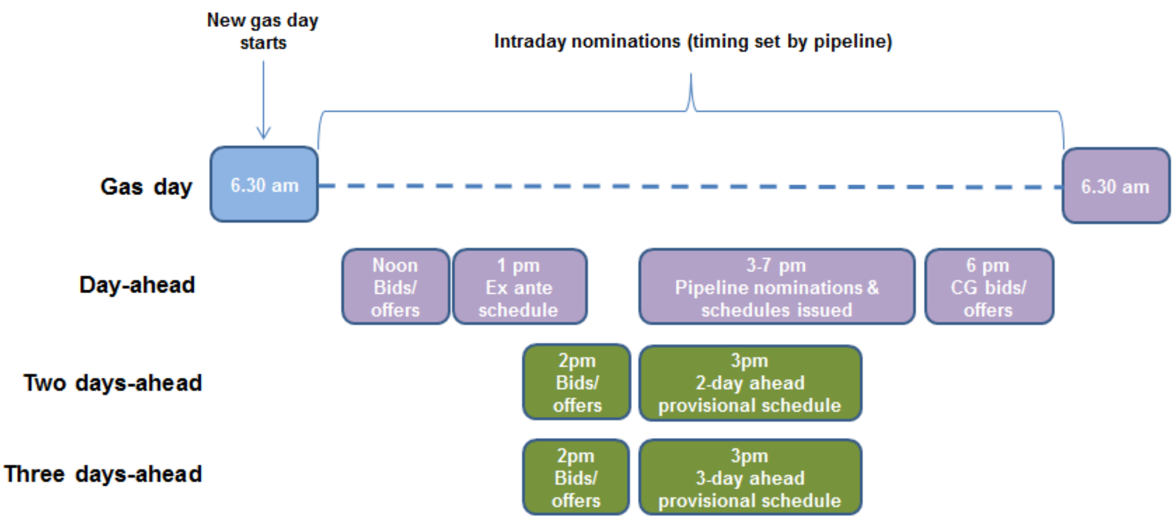
During this scheduling process, one or more pipelines might reach their hub capacity—the pipeline is then said to be capacity constrained. If demand at the hub has not been met when a pipeline becomes constrained, the scheduling process continues as before, but offers are only considered from unconstrained facilities. Demand can be satisfied from any STTM transmission pipeline or other facility subject to its physical capacity on the gas day.[549]

After the ex ante market schedules are published, shippers make nominations to pipeline operators in accordance with their relevant contracts. This process is not part of the STTM and there is no requirement for pipeline nominations to match the quantities scheduled in the market. Similarly, the STTM has no involvement in any distribution network processes for managing the scheduling of withdrawals from a hub. If nominations differ from the STTM ex ante schedules, this is dealt with through the on-the-day balancing mechanism, which is discussed below.

Figure E.4 shows the timeline for a typical STTM day in Adelaide and Sydney in Eastern Standard Time.[550] Two and three days before the gas day, AEMO publishes provisional schedules, giving participants a three-day outlook for estimated supply and demand at each hub. The day before gas is to flow, shippers and users must submit their bids and offers to AEMO by 12.00pm. At 1.00pm AEMO issues the ex ante market schedule for the following day.

Between 3.00pm and 7.00pm participants submit their nominations to the pipeline operators for the next day and the schedules are issued by the pipeline operator.[551] The gas day starts at 6.30am the following morning. During the gas day, and in accordance with renomination processes, shippers and users are able to request intraday nominations to the pipeline operator.

Figure E.4 Adelaide and Sydney STTM timeline



Source: AEMC, based on AEMO Industry Guide to the STTM v3.5 and AEMO STTM training material.

549 AEMO, Industry Guide to the STTM, December 2014, p. 33.

550 Timings for the Brisbane STTM are 1.5 hours after Adelaide and Sydney.

551 AEMO, Industry Guide to the STTM, December 2014, p. 13.

E.2.3 On-the-day balancing mechanism

The on-the-day balancing mechanism is the second design element of the STTM and the primary role of the market in the broader east coast framework. Without the STTM or other form of balancing market, pipeline operators would balance the system under a service negotiated as part of long term bilateral contracts with their customers (as was done prior to the introduction of the STTM).

On-the-day balancing is a common feature of wholesale gas market designs due to the physical properties of natural gas. Unlike electricity, gas does not flow to its destination almost instantaneously. This requires users to provide producers and pipeline operators with forecasts of their demand the day before gas is required. On-the-day balancing is required to resolve the variations in ex ante schedules and actual flows on the gas day.

Unlike the Victorian DWGM, there is no opportunity for STTM participants to adjust their positions during the gas day. In order to manage imbalances that occur at the hub between the ex ante market schedule and actual physical flows, AEMO operates the following mechanisms throughout the gas day:

- Market Operator Service (MOS);
- Market Schedule Variations (MSVs); and
- Contingency gas.

Each of these mechanisms are discussed below, along with an overview of how the ex ante commodity market and on-the-day balancing mechanism are financially settled.

Market Operator Service

MOS balances the difference between the scheduled pipeline flows and what is actually delivered or consumed at the hub, and is the primary on-the-day balancing mechanism. It is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges, which are discussed in section E.2.4 below.

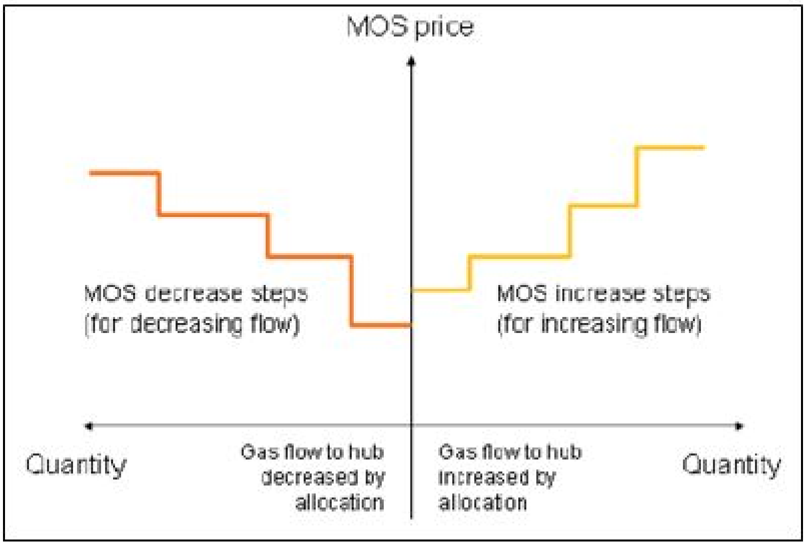
MOS is currently procured each month by AEMO from shippers with contracts on STTM-connected transmission pipelines. Shippers provide MOS increase offers for increased flows to the hub and MOS decrease offers for decreased flows to the hub, which are comprised of price-quantity steps.

On a gas day where deviations from the ex ante schedules occur, MOS is allocated to shippers by pipeline operators in accordance with MOS stacks provided for each pipeline by AEMO. If demand at an STTM hub is higher than expected, and as a result pipeline pressures decrease below operational levels, the pipeline operator flows additional gas from linepack in accordance with the increase MOS stack. Similarly, if hub demand is less than expected, the pipeline operator decreases the flow of gas to the hub by storing gas in the pipeline in accordance with the decrease MOS stack.

After the gas day, the pipeline operators notify AEMO of all MOS allocations for settlement purposes. This information also feeds into setting the ex post imbalance price, which is discussed further in section E.2.4.

Figure E.5 shows a MOS decrease stack on the left, where price increases as more gas is required to be stored in linepack, and a MOS increase curve on the right, where price increases for the more gas that is required to be supplied into the hub from linepack. A MOS cost cap of $40/GJ is the maximum amount that AEMO will pay for MOS. This is designed to protect the market from having to fund high costs for MOS where there is a lack of competition in the provision of MOS.

Figure E.5 MOS increase and decrease price stacks



Source: AEMO.

The price offered by a shipper to provide MOS reflects the cost of the pipeline park-and-loan service, and associated haulage charged by the pipeline operator, but not the cost of replacing the gas supplied.[552] When the market is short and MOS gas is required, the shipper is paid according to their MOS step price on a pay-as-bid basis. There is no cost to the market in accepting a MOS offer until MOS gas is actually allocated on a gas day.[553]

AEMO pays the MOS provider for the additional gas, or charges it for taking gas from the hub, at the ex ante market price two days after the gas day. This D + 2 ex ante price is used to price the cost of replacing MOS inventory as it allows the MOS provider to protect itself from price risks. An example of how this mechanism works is set out in Box E.1.

552 Ibid, p. 37.

553 Ibid.

Box E.1 Replacing MOS gas supplied to the STTM

If a MOS provider supplies MOS on gas day 'D' due to a shortage at the STTM hub, AEMO will pay the MOS provider at the ex ante price two days later, or D+2, for that gas.

Paying the shipper at the D+2 price allows the shipper to bid to purchase gas to resupply its MOS inventory at the same price that AEMO has paid it for supplying the MOS gas. As such, the MOS provider is able to replenish its gas inventory without the risk of receiving a lower price that than paid by AEMO for supplying MOS gas to the STTM.

For instance:

- MOS provider supplies 5 TJ of MOS gas on gas day D.
- At D+2 AEMO pays the MOS provider $3/GJ for supplying MOS gas.
- On the same day the MOS provider has the opportunity to bid to purchase gas to resupply its MOS inventory at $3/GJ.

In the Sydney STTM, MOS is provided on the Moomba to Sydney Pipeline and the Eastern Gas Pipeline. In Adelaide, MOS is provided by SEAgas and the Moomba to Adelaide Pipeline. In Brisbane, MOS is provided on the Roma to Brisbane Pipeline.

At the Sydney and Adelaide hubs, one of the transmission pipelines supplying the hub operates as a pressure control pipeline and the other operates as a flow control pipeline.[554] Pressure control pipelines generally provide the bulk of MOS gas.[555]

Market schedule variations

During the gas day, users' gas requirements become clearer and shippers are generally able to submit renominations to pipeline operators to adjust the flow of gas to the hubs. AEMO is able to account for intraday nominations, and shippers avoid deviation payments and charges, if shippers submit a market schedule variation (MSV) to AEMO to account for the changes.

MSVs are bilateral agreements negotiated between participants outside of the STTM that allow the quantity of gas by which a shipper varies from the market schedule to be matched by a receiving shipper or user. The receiving participant must confirm acceptance of an MSV before the variation can be applied in the STTM settlement process.[556]

If the MSV results in a change in demand at the hub, the variation will attract a variation charge, which is designed to encourage more accurate day-ahead forecasting. Variation charges are calculated on a sliding scale on a quantity and percentage basis such that the larger the variation, the larger the charge. MSVs that do not change the net flow at the hub are not penalised.

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554 Flow control pipelines provide gas at a constant flow rate throughout the day while pressure control pipelines deliver gas to meet changes in the pressure at the hub.

555 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p 14.

556 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 47.

The framework around variation payments and charges is designed to provide an incentive for shippers and users to forecast their expected volumes accurately, while acknowledging that some changes are inevitable under the day-ahead market design. Variation charges are lower than deviation penalties (see section E.2.4) to encourage shippers to re-nominate expected changes in gas required to the pipeline operator.

Box E.2 illustrates how MSVs can be used in the STTM by participants.

Box E.2 MSVs are used by participants to avoid penalties[557]

If, say, a retailer has been scheduled to flow 10 TJ in the ex ante scheduling process and, as the gas day unfolds, it has become clear that 12 TJ will be required. During the gas day the retailer may be able to ask the pipeline operator to flow an additional 2 TJ of gas.

If the retailer fails to inform AEMO that it has scheduled a further 2 TJ, AEMO will assume that the retailer, who in this case is a shipper and user, has over-supplied the market by 2 TJ and over-consumed by 2 TJ. A deviation payment and charge will be subsequently applied.

To avoid the deviation payment and charge associated with not following the ex ante schedules, the retailer can submit an MSV instructing AEMO to modify its shipper schedule by 2 TJ and its user schedule by 2 TJ. As the net impact at the hub is zero, the modified market schedule ensure no deviations payments or charges are applied.

Contingency gas

Contingency gas is a mechanism for balancing supply and withdrawals at a hub when the ex ante market and on-the-day pipeline flow variations are unable to match supply and demand within or over a gas day. Contingency gas provides pipeline operators and distributors with a means of avoiding, or at least minimising, the need to involuntarily curtail shippers supplying the hub or users at the hub.

AEMO procures contingency gas, but its use is determined in consultation with transmission pipeline and distribution network operators. Shippers able to increase supply to a hub and users and shippers able to reduce consumption will offer contingency gas to meet under-supply situations. Shippers able to decrease supply and users and shippers able to increase consumption at a hub will bid contingency gas to meet over-supply situations.

Trading participants can submit bids and offers for contingency gas at any time up to 6.00pm the day before gas day. Contingency gas bids and offers are priced between the minimum and maximum market price caps. AEMO determines a price for contingency gas after the gas day, when all contingency gas called is known.[558]

A high contingency gas price is paid to providers whose contingency gas increases supply and/or reduces withdrawals. This price is set at the contingency gas offer price of the most expensive contingency gas provider who is called.

557 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 47.

558 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 41.

A low contingency gas price is paid by contingency gas providers whose contingency gas decreases supply or increases consumption. This price is set at the contingency gas bid price of the least expensive contingency gas provider called.[559]

Contingency gas has not yet been required at any of the STTM hubs to-date.

E.2.4 After the gas day

After the gas day the following aspects of the market are required to be determined for settlement to take place:

- actual gas flows;
- ex-post imbalance price;
- deviation payments and charges; and
- market settlement shortfall and surplus.

Determining actual gas flows

After the gas day, transmission pipeline operators for each STTM facility measure actual pipeline flows and allocate these quantities to each shipper on that pipeline. Where the pipeline allocations at a hub deviate from the ex ante schedule, the pipeline operator allocates these deviations to MOS providers in accordance with the MOS stacks provided by AEMO.

Distribution meter data is collected over a range of time frames and requires that non-interval meter customers are profiled. The quality of meter data available improves over time, so the meter data provided for the first settlement run is generally inferior to that of subsequent settlement runs produced over a period of months. These are functions that AEMO carries out in its capacity as retail market operator and are not part of the STTM.[560]

Settlement occurs monthly, but is recalculated after nine months due to the time it takes for meter data to be finalised. The STTM provides for further revisions for a period of 18 months if there is material impact on participants due to mistakes in the process or if faulty meters are discovered.[561]

Ex post imbalance price[562]

The ex post imbalance price is calculated after the gas day to determine a price that reflects the changes that actual flows to the hub would have had on the ex ante market. It is determined using the same data as the ex ante market schedules, but includes a dummy bid or offer that simulates the effect of the deviations, such as through MOS, if they had been scheduled in the ex ante market.

If more gas was scheduled than consumed on the gas day, the market supply curve is moved right by the quantity by which the market is long. If more gas was consumed

559 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 43.

560 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 46.

561 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 53.

562 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 49-50.

than scheduled, the market demand curve is moved right by the quantity by which the market is short.

The ex post imbalance price is published after the gas day and can be used in settlement to calculate deviation payments and charges.

Deviation payments and charges[563]

Deviations are the difference between the quantity of gas that the STTM is expecting to flow—as modified by MSVs, MOS and contingency gas—and the actual quantity of gas that flowed. As discussed above, actual quantities of gas that flow to and from the hub will not exactly match the ex ante market schedule for any given gas day.

Where a shipper has supplied more gas than was required in the market schedule, or a user consumed less gas than was expected in the market schedule, it will receive a deviation payment from AEMO. The deviation payment is calculated by multiplying the deviation quantity by the minimum of the ex ante price, ex post price, the decrease MOS price (if any) and the low contingency gas price (if any).

Where a shipper or a user is "short" at the hub, it must pay a deviation charge to AEMO. Deviation payments and charges are used to offset the cost of MOS gas. The deviation charge is calculated by multiplying the deviation quantity by the maximum of the ex ante price, ex post price, the increase MOS price (if any) and the high contingency gas price (if any).

Deviation payments and charges reflect the impact the deviation had on the STTM and will vary for each participant. However, because deviations and MOS are calculated on a different basis, there is usually a shortfall or surplus, which is dealt with through the settlement process described below.

Market settlement shortfall and surplus[564]

Settlement occurs monthly and is net of all ex ante sales and purchases, deviations charges, variation charges, capacity charges, settlement revisions and any payments for MOS and contingency gas. The settlement payments to trading participants do not usually match the settlement charges paid by trading participants, with the various components above all contributing to the market being in surplus or shortfall.

For each month, the market must end up in balance with respect to trading income and outgoings. If there is a shortfall, any deviating parties are charged their share of the shortfall, pro-rated based on the absolute value of their deviations over the course of the month.

If there is a surplus, then the excess money is returned to the deviating parties based upon their share of monthly deviations up to a cap of 0.14 $/GJ, with the residual amount being returned pro-rata based on withdrawals over the course of the month.

E.3 STTM rule changes

The following table sets out the STTM rule changes considered by the AEMC since market start.

563 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 49.

564 AEMO, *STTM operational review and demand hubs review final report*, 30 March 2012, p. 53-57.

Table E.2 STTM rule changes

Determination date	Proponent	Rule change	Brief Description
12 February 2015 (Draft Rule Determination)	AEMO	Contingency Gas Evidentiary Changes	Improve incentives for trading participants to efficiently supply and price contingency gas in the STTM.
3 April 2014	AEMO	STTM settlement surplus and shortfall	Provides guidance to AEMO to develop STTM Procedures for the allocation of any settlement surplus or shortfall to STTM participants.
20 June 2013	AEMO	STTM deviations and the settlement surplus and shortfall	Reduce the financial risks of market participation and improve price signals and certainty regarding the costs to trading participants of deviating from their daily schedules.
23 May 2013	AEMO	Market operator service - timing and eligibility	Facilitate greater competition in the provision of MOS in the STTM.
28 February 2013	AEMO	STTM Brisbane participant compensation fund	Increase the size of the STTM Brisbane compensation fund as the existing arrangements did not reflect the size of the Brisbane market.
28 August 2012	AEMO	STTM Market Schedule Variation Transactions	Enables users in the STTM to submit MSVs to AEMO.
13 October 2011	AEMO	Short Term Trading Market - Market Schedule Variation	Removal of the timing provision for the submission of MSV transactions from the NGR.
15 September 2011	AEMO	Brisbane Hub	Implement the Brisbane STTM.
5 May 2011	AEMO	STTM Data Validation and Price Setting Process	Provide the market operator with more time to review and confirm the accuracy of STTM information.

Determination date	Proponent	Rule change	Brief Description
17 March 2011	AEMO	Calculation of STTM Participant Compensation Fund Contributions	Clarify the process of calculating the STTM Participant Compensation Fund.
9 December 2010	AEMO	Timetable for Prescribed Gas STTM Reviews	Consolidate the first three prescribed STTM reviews to be completed by 31 March 2012.
4 November 2010	AEMO	Calculation of interest rate for gas markets	Provides for the calculation of interest in the NGR to use a simple interest methodology.

E.4 STTM participants

The following tables list the registered participants in each of the STTM hubs.

Table E.3 Adelaide STTM

Adelaide STTM	
Shippers AGL, Adelaide Brighton Cement, Alinta, EnergyAustralia, Lumo, OneSteel, Origin, Pelican Point Power, Santos, Simply Energy, South Australian Water Corporation	**Users** AGL, Adelaide Brighton Cement, Alinta, EnergyAustralia, Lumo, Origin, Simply Energy, South Australian Water Corporation
Pipeline owners Australian Gas Networks (Envestra), Epic Energy, SEA Gas	**Other** Logica GRMS

Table E.4 Brisbane STTM

Brisbane STTM	
Shippers AGL, Alinta, BP Australia, ERM Business Energy, Incitec Pivot, Origin, Santos, Stanwell	**Users** AGL, Alinta, BP Australia, Incitec Pivot, Origin, Stanwell, Visy Paper
Pipeline owners APT Petroleum Pipelines (RBP - APA Group), Allgas Energy, Australian Gas Networks (Envestra)	**Other** AEMO (allocation agent)

Table E.5 Sydney STTM

Sydney STTM	
Shippers AGL, BHP Billiton Petroleum, BlueScope Steel, Covau, EnergyAustralia, Esso Australia, Lumo, OneSteel, Origin Energy, Qenos, Santos	**Users** AGL, BlueScope, Covau, EnergyAustralia, GOEnergy, Lumo, OneSteel, Origin, Qenos, Red Energy, Santos, Snowy Hydro, Visy Paper
Pipeline owners East Australian Pipeline (MSP - APA Group), Jemena Eastern Gas Pipeline, Jemena Gas Networks	**Other** Logica GRMBS

Source: AEMO data.

F Operation of the Declared Wholesale Gas Market

This appendix provides a detailed overview of the DWGM design and operation. It sets out the:

- history and policy objectives of the DWGM;
- design and structure of the DWGM;
- rule changes carried out by the AEMC to-date; and
- current market participants in the DWGM.

F.1 History and policy objectives of the DWGM

Market-start

The DWGM was established by the Victorian Government in March 1999 and as part of this process, the following occurred:[565]

- the ownership and operational functions of the pipeline transmission system were separated and a decision was made to operate the DTS on a market carriage basis;
- the DWGM was developed to enable participants to trade imbalances; and
- an independent system operator, VENCorp (later AEMO), was given responsibility for operating both the DWGM and the DTS, balancing gas supply and demand and transportation capacity through a centrally co-ordinated scheduling process.[566]

The rationale for adopting the market carriage model[567] and the DWGM in Victoria can be summarised as follows:[568]

1. It reflects the physical characteristics exhibited by the DTS:
    - The DTS is highly a meshed network.
    - The amount of gas that can be stored in the DTS is also quite small and cannot be relied upon to manage significant deviations between demand and contracted supply.[569]

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565 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 53.

566 VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 22.

567 Under a market carriage framework, capacity on a pipeline system is available to all users. A shipper does not have rights in relation to being able to use capacity nor would it face penalties for exceeding a certain capacity. Market carriage in Victoria (and its difference to contract carriage elsewhere) is covered in detail in chapter 4.

568 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11; and VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, pp. 21-24.

569 A 2002 report by VENCorp states that total linepack in the DTS varies between about 450 TJ and 600 TJ over each day as the system demand is satisfied and that on peak days over 1,100 TJ is shipped through the network, or approximately twice the entire linepack in the system. By way of comparison, the then peak demand on the Moomba pipeline was stated to be approximately 25 per cent of the daily transported volume. See: VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 23.

- The physical characteristics of the DTS, coupled with the fact that the demand for gas in Victoria exhibits a significant degree of seasonal and daily variability (high residential heating load), mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained.
- The physical characteristics exhibited by the DTS also mean that it can be very difficult to determine how to define firm capacity rights to shippers.[570]

2. It was expected to support full retail contestability – The market carriage model and the DWGM were seen as a way of encouraging new entry by retailers because they would not need to enter into long term gas transportation agreements and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.
3. It was designed to encourage diversity of supply and upstream competition – The transparency of pricing provided by the DWGM and the operation of the market carriage model were expected to encourage the development of new sources of supply and upstream competition.

Move to ex ante intra-day trading

Between 1999 and 2007, the DWGM market price was determined on a daily ex-post basis. However, on 1 February 2007, the market moved to ex ante intra-day trading following a review in 2003-04 by VENCorp. The 2003–04 review, also known as the Pricing and Balancing Review (PBR), aimed to:[571]

- provide more efficient and transparent pricing signals;
- improve market interaction and response to pricing signals;
- provide adequate incentives and flexibility for demand-side response; and
- facilitate investment in pipeline infrastructure.

VENCorp recommended a three stage approach to reforming the DWGM, namely:[572]

1. stage 1: introduction of ex ante intra-day pricing;
2. stage 2: introduction of transmission rights; and
3. stage 3: development of a number of hubs and introduction of capacity rights.

To date, the only changes that have been made to the DWGM are those that were recommended to occur in stage 1. VENCorp found that the existing ex post design did not provide participants with either the ability or the incentive (ie the price signal) to respond to changing market conditions during the day, which was a driver behind switching to a system of ex ante pricing in 2007.[573]

570 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11.

571 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013, pp. 11-12.

572 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 55.

573 VENCorp, *Victorian Gas Market Pricing and Balancing Review – Recommendations to Government*, 30 June 2004.

Authorised Maximum Daily Quantity

Shippers utilising the DTS cannot reserve firm capacity (unlike contract carriage pipelines). They may, however, have an Authorised Maximum Daily Quantity (AMDQ) allocation or an AMDQ credit certificate (AMDQ cc).[574] This section presents the history of AMDQ and AMDQ cc. A detailed discussion of the benefits to holders of these two products is provided in section F.2.2 below.

AMDQ was first allocated at market start and was (and has remained) commensurate with the capacity of the Longford-Melbourne pipeline at that time when it was the primary sole source of gas supply for the DWGM. The rights to the existing 990 TJ of capacity were allocated to customers in two tranches (recognising that the DTS was comprised of pre-existing assets that had at least partially been paid for by existing customers of the Victorian Gas and Fuel Corporation):

1. large industrial and commercial (Tariff D) sites were allocated AMDQ to match their maximum daily quantity under contracts with the Victorian Gas and Fuel Corporation at the time; and
2. the balance of 990 TJ, after Tariff D allocations, was allocated as Tariff V block AMDQ to all small commercial and residential customers.[575]

The rationale for allocating the original AMDQ to customers rather than market participants, retailers or shippers was to not create a barrier to retail competition.[576]

The DTS has expanded and extended since 2008 and the new pipeline capacity has been allocated as AMDQ credit certificates (AMDQ cc).[577]

As new pipeline capacity has become available, AMDQ cc have been created to provide similar benefits to those arising from AMDQ on the Longford pipeline.[578] The increase in pipeline capacity resulting from an extension or expansion project is agreed between APA (as the DTS owner) and AEMO (the operator of the DTS and the DWGM). Once agreement is reached and the new capacity becomes operational, new certificates are created.

AEMO allocates the AMDQ cc to market participants for quantities and periods as directed by APA (which reflect the outcome of a competitive tender process APA

574 Unless otherwise stated, the information in this sub-section references: AEMC, *National Gas Amendment (Portfolio Rights Trading) Rule 2014*, Final Rule Determination, 27 November 2014.

575 Market participants supplying Tariff V customers were allocated a share of the Tariff V block AMDQ proportionately to their portfolio Tariff V demand on system peak demand days.

576 For example, if AMDQ were held by retailers, there was a concern that those retailers who won customers from rival retail businesses would then be forced into a position of either trying to negotiate with that rival retailer to sell them AMDQ, or take on additional risk

577 Maximum system capacity of the DTS is currently approximately 1,350 TJ per day. See: AEMO website, available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-DTS-Capacity

578 Since the commencement of the DWGM, the capacity of the DTS has increased as a result of numerous augmentations, including the Interconnect, the South West Pipeline, the connection of the former Western Transmission System, the Brooklyn Lara Loop and the BassGas project.

manages). In this process, interested market participants are able to tender for an amount of AMDQ cc for a specified period.[579]

Figure F.1 illustrates the expansion of the DTS since 1998, which has resulted in a total of 508 TJ of AMDQ cc made available for injections into the DWGM.

Figure F.1 Allocation of AMDQ and AMDQ cc as at 2014

Source: AEMC, *National Gas Amendment (Portfolio Rights Trading) Rule 2014*, Final Rule Determination, 27 November 2014, p. 32.

AMDQ cc is not differentiated by final customer (Tariff V or D) and is not allocated directly to customers. Rather, market participants with AMDQ cc must advise AEMO whether the allocated AMDQ cc are to be nominated to either:

- specific customer sites; or
- the nominal reference hub.[580]

Rule changes

Section 295(3) of the NGL currently provides that applications for rule changes relating to the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[581] Since commencement of the DWGM in 1999, AEMO has submitted six rule changes to the AEMC for consideration since it assumed responsibility for rule changes from VENCorp in 2009. These are summarised in Table F.1.

F.2 Design and structure of the DWGM

It is compulsory for market participants in Victoria to trade through the DWGM. In particular, any retailers, large customers or gas traders that want to either supply gas into Victoria, or export gas via the DTS, must use the DWGM. A range of participants,

579 However, the AEMC note there are no requirements for this process to occur.

580 The reference hub is a notional site within the DTS established for the purpose of valuing AMDQ and AMDQ cc. When a market participant does not nominate its entire AMDQ to actual sites, it has to nominate its residual AMDQ somewhere

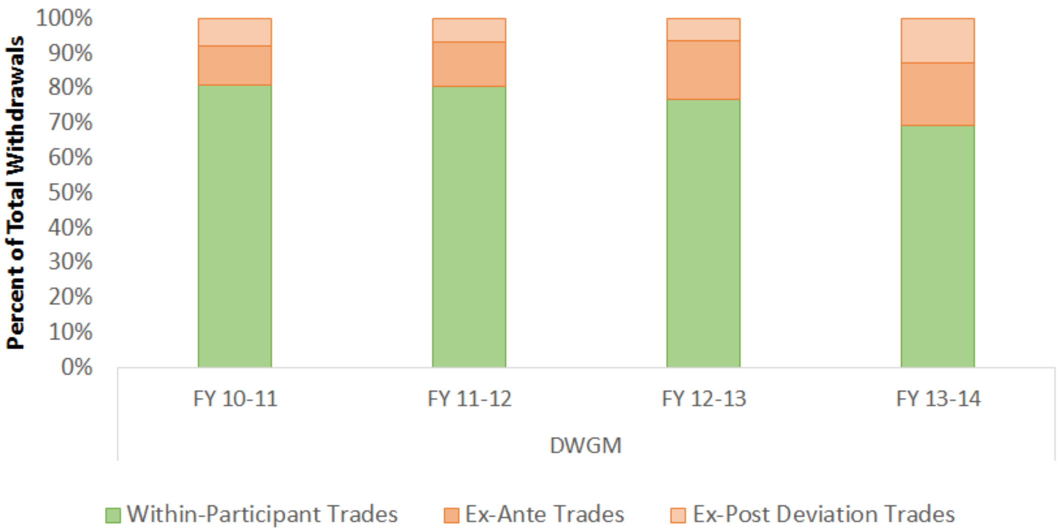
581 Victoria is currently the only adoptive jurisdiction.

such as retailers, gas-fired generators and large industrial customers, currently use the DWGM. Participants all use the market to physically sell or procure gas. Table F.2 sets out the number and type of participants currently registered in the DWGM.

An important feature of the arrangements in Victoria is an independent market and system operator (AEMO) that operates the pipeline separately from the pipeline owner. It manages the receipt, transport and delivery of gas as part of the gas market. APA makes the Victorian DTS available to AEMO under a Service Envelope Agreement (SEA) and makes available a single reference service comprising a Tariff Transmission Service.[582]

Figure F.2 categorises DWGM transactions into three types: within-participant trades, ex ante trades and ex-post deviation trades. The chart shows that at least 80 per cent of transactions in the DWGM are within-participant. A fee of $0.082/GJ of gas that is withdrawn from the DTS is currently required to be paid to AEMO, irrespective of whether two related entities are trading between themselves.

Figure F.2 Vast majority of trades on the DWGM are within-participant



Source: AEMO data provided to the AEMC. Within-participant trades is the quantity of gas transacted between the same entity; ex ante trades is the quantity of gas traded between different entities at the start of the gas day; ex post deviation trades is deviations during the gas day.

The key features of the current DWGM market are as follows:

- the market sets the ex ante prices for gas trades at a publicly available price at the beginning of each scheduling period, enabling participants to respond to prices;
- the market is a net market allowing settlement on the difference between a market participant's injections and withdrawals (imbalance);
- market participants submit injection and/or withdrawal bids and their own demand forecasts; AEMO uses these to produce the overall system forecasts;
- there are five scheduling times (6.00am, 10.00am, 2.00pm, 6.00pm and 10.00pm) where schedules covering the remainder of the gas day can change;

582 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 11.

- settlement payments are determined for each scheduling time based on traded quantities and prices; and
- mechanism of ancillary payments and uplift cost allocations are used to manage the cost and impact of transmission constraints.

A more detailed overview of the key design features of the DWGM and how they work in practice are provided below.[583]

F.2.1 DWGM overlay with market carriage pipeline framework

To ship gas through the DTS, shippers must register with AEMO as a participant in the DWGM. In doing so, shippers must enter into a Transmission Payment Deed with APA, which states that shippers agree to pay regulated transmission tariffs directly to APA as owner of the DTS. Tariffs for use of the DTS are known as Transmission Use of System (TUoS) charges and reflect the cost to deliver gas from the seven injection points to the 27 withdrawal zones and points on the DTS.[584]

Shippers proposing to withdraw gas from the market must also enter into a connection agreement with either a gas distribution company or APA, or have arrangements to transport the gas to a connected transmission pipeline.

F.2.2 Authorised Maximum Daily Quantity

Collectively, AMDQ and AMDQ cc are commonly known as "AMDQ."[585] Broadly, there are two different types of right (or benefits) that are created by holding AMDQ, namely:

1. Financial rights: Market participants can use part or all of their AMDQ to hedge against congestion uplift charges.[586]
2. Physical access rights:
   (a) Curtailment 'protection' rights - unauthorised customers, where operationally practicable, will have their gas supply curtailed ahead of customer sites with AMDQ in the event of transmission constraints resulting in supply shortfalls.[587]
   (b) Injection tie-breaking rights (also known as priority in scheduled injections) – when there are equally priced injection bids, participants with AMDQ are scheduled first.

583 Unless otherwise stated, the information in this sections below reference: AEMO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

584 APA group website, available at: http://www.apa.com.au/our-business/economic-regulation/vic/victorian-transmission-system.aspx

585 Unless otherwise stated, the information in this sub-section references: AEMC, National Gas Amendment (Portfolio Rights Trading) Rule 2014, Final Rule Determination, 27 November 2014.

586 We note that AMDQ only offer a limited hedge against congestion uplift and no hedge against surprise or common uplift. This is discussed further in section F.2.9.

587 In practice, we understand this is limited.

(c) Withdrawal tie-breaking rights (also known as priority in scheduled withdrawals) – when there are equally priced controllable withdrawal bids, participants with AMDQ are scheduled first.

In 2014 the procedures pertaining to AMDQ were modified to incorporate a proposal by APA to enhance interoperability between the DTS market carriage system and adjacent contract carriage markets. Specifically, the procedures were modified so that AMDQ was only assigned to a system withdrawal point at an interconnected facility (eg at Culcairn) if a market participant was entitled to sufficient firm capacity on that interconnected facility to cover the quantity being assigned and any existing holdings (ie, that the market participant holds sufficient firm haulage contracts for the AMDQ allocation to occur).[588]

AMDQ can be acquired in a number of ways, including by:

- entering into an agreement with existing holders of AMDQ to transfer an agreed quantity from one site to another or to the reference hub;
- entering into an agreement with existing holders of AMDQ cc to transfer an agreed quantity at the reference hub;
- apply and negotiate with the DTS service provider for AMDQ cc when they expand the capacity of the DTS or when existing AMDQ cc contracts that others hold expire;
- contract with the DTS service provider to privately expand the DTS capacity;[589] and
- bid for and purchase spare AMDQ at auctions conducted by AEMO from time to time.

Historically, limited quantities of AMDQ have been traded between participants. In its 2011 paper outlining transmission capacity issues in the DWGM, AEMO noted it had auctioned 12.5 TJ of unallocated AMDQ from defunct Tariff D customer sites and has transferred a further 75 TJ in 106 transactions since transfers commenced in 2001. Of the transfers, 43 per cent by volume and 65 per cent by number were internal transfers to related organisations.[590]

F.2.3 Bidding procedure

Before outlining the specific bidding procedures currently in the DWGM, it is first useful to outline the three concepts of supply and demand in the DWGM, ie:

1. Controllable withdrawals (demand):
    - Market participants can make offers to withdraw gas from the market with a defined gas quantity and price.

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588 See: AEMO, *AMDQ Procedure Proposal*, 28 February 2014; and AEMO, *Notice to Participants of AEMO's decision on making the Wholesale Market AMDQ Procedures (Victoria)*, 10 June 2014.

589 We understand that this has not happened yet to date.

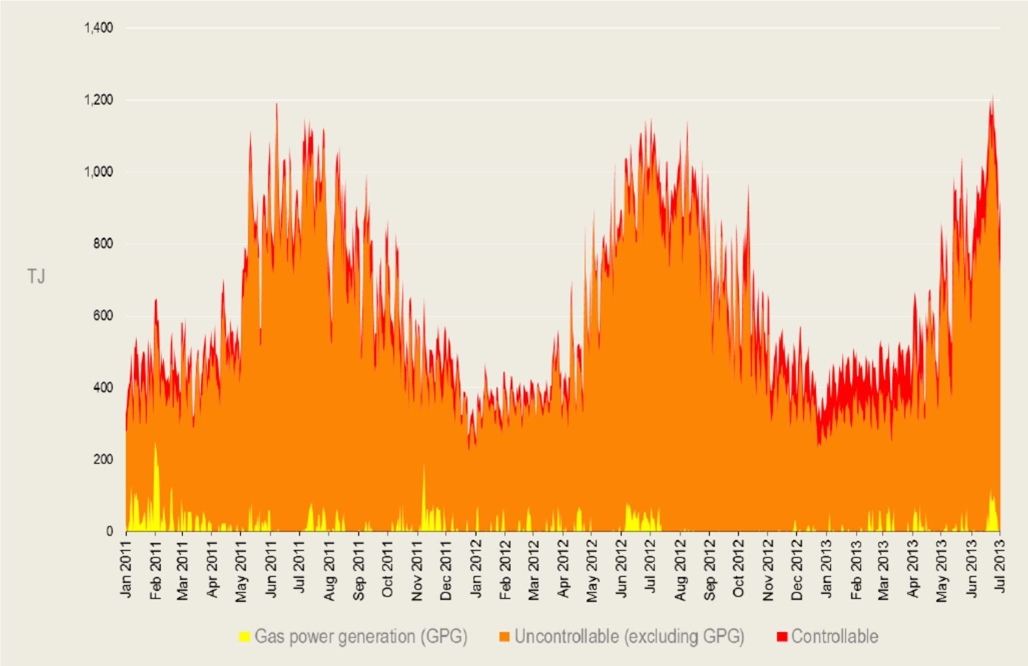
590 AEMO, *Transmission Capacity Issues in the DWGM*, 21 June 2011, p. 6.

- This type of withdrawal can respond to the wholesale price and follow schedules and so is termed "controllable withdrawal."

2. Uncontrollable withdrawals (demand):
   - Most of the gas demand in the DWGM varies with temperature, seasons, day of week, weather conditions, and various other external factors.
   - Generally, the highest gas loads occur during the winter. Typical examples of these types of withdrawals include gas demands from households (heaters, hot water), small and large business/industry, and Gas Fired Power (GFP) generators (many of them are "peaking" plants as they can respond to change in NEM demand and prices, unlike coal-fired power plant).
   - Since these withdrawals do not easily respond to the wholesale price and are not capable of following schedules, they are termed "uncontrollable withdrawals."
3. Injections (supply):
   - Market participants need to have contracts with producers, storage providers, or interconnecting transmission systems to be able to inject.
   - Similar to controllable withdrawals, market participants can make offers to inject gas to the market with a defined gas quantity and price.
   - Injections are termed "controllable," because they can respond to the wholesale price and follow schedules.

Figure F.3 below shows total withdrawals from the DWGM over the period 2011 - 2013, showing that in Victoria the vast majority of demand comes from uncontrollable sources such as households (heaters, hot water etc) as well as small and large business/industry.

Figure F.3 **Uncontrollable demand makes up the majority of DWGM demand, daily data 2011 - 2013**



Source: AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013, p. 15.

Market participants who intend to inject gas or withdraw gas as controllable withdrawals must submit bids to do so.

Market participants can specify up to ten steps of prices and daily quantities in each bid for each injection and controllable withdrawal point:

- for injection bids, bid steps are provided in increasing price order with increasing cumulative quantities; and
- for controllable withdrawal bids, bid steps are provided in decreasing price order with increasing cumulative quantities.

Bid prices can vary between $0/GJ and the market price cap (Value of Lost Load (VOLL)) which is currently set at $800/GJ.

Market participants may revise price and quantity bids at least nine times per day (the scheduling/re-scheduling process is outlined in more detail in section F.2.4 below). However, the revised total bid quantities must not be less than that already scheduled in any previous schedules on that gas day. All bid quantities, including rebids, are for the 24 hour gas day.

F.2.4 Gas scheduling

Gas scheduling is a process that AEMO conducts a number of times each gas day to provide hourly injection schedules for each market participant, and schedules for any controllable withdrawals, using market participants' submitted bids and demand forecast[591] as the primary inputs.[592]

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591 Market participants who supply uncontrollable withdrawals must submit hourly site- and non–site-specific demand forecasts to AEMO.

Specifically, AEMO uses this information to produce and publish pricing and operating schedules at each scheduling time. Namely:

- Operating schedules:
  - Determines individual market participant's scheduled hourly injections and withdrawals at each injection/withdrawal point.
  - Takes into account physical pipeline constraints, linepack distribution, system limits on pressure and gas flows and demand and supply applicable to each node.
  - The market clearing algorithm used in optimising each operating schedule minimises the cost of supplying the forecast gas demand within the pipeline system security limits.
  - Quantities from operating schedules direct the operation of the gas system and injections into the system over the gas day.
- Pricing schedules:
  - Determines the ex ante market prices based on the bids and demand forecasts (ie using a 'bid stack') for all locations on the network. This process is outlined in more detail in section F.2.5 below.

On any given gas day, AEMO prepares and issues at least nine pricing and operating schedules, ie:

- five standard schedules for the current gas day at four-hour intervals at 6.00am, 10.00am, 2.00pm, 6.00pm, and 10.00pm;
- three gas schedules for the next gas day at 8.00am, 4.00pm and 12.00am;
- one two-days-ahead schedule for gas day after the next day at 12.00pm; and
- ad-hoc schedule(s) between standard schedules on the current gas day, but only if there are impending or imminent threats to system security requiring urgent action.[593]

The 6.00am schedule, also known as the beginning-of-day (BoD) schedule, covers the 24 hours from 6.00am. Information used and issued in the BoD schedule is updated in subsequent re-schedules and the 10.00am, 2.00pm, 6.00pm and 10.00pm re-schedules provide for any changes for the remaining 20, 16, 12 and 8 hours of the current gas day, respectively.

The period between scheduling times is called the scheduling interval, and the period of time from any point in a day to end of gas day is called the scheduling horizon. The scheduled quantities are for the whole gas day (hour by hour) but only the part in the scheduling horizon can be changed.

The preparation of schedules by AEMO in any given day (and the timing of these schedules) is shown in Figure F.4.

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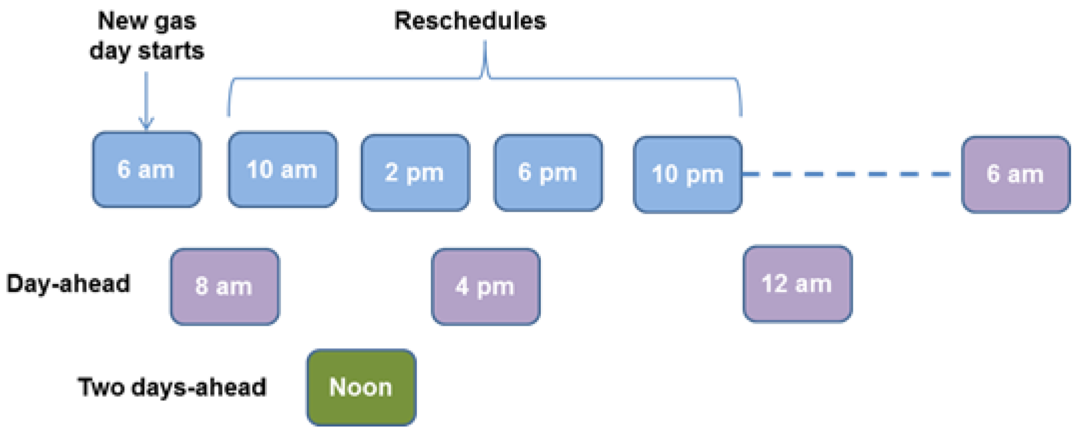
592 We note that the form that market participants enter market bids in is by schedule, while demand forecasts are entered by hour.

593 Ad hoc schedules do not alter the Market Price. They change operating schedule quantities only.

Figure F.4 The daily preparation of schedules by AEMO



Source: AEMC based on AEMO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

Market participants need to submit the required scheduling input data at least one hour prior to the schedule start time for all standard schedules.[594] This allows AEMO time to compile and assess the input data, run the algorithms, and confirm that the outputs are satisfactory before issuing the schedules.

After the scheduling process, each market participant receives the key output of the operating schedule – an individual Market Information Bulletin Board report detailing what quantity of gas and where they are committed to inject or withdraw for each hour of the gas day.

F.2.5 Determination of the ex ante market price

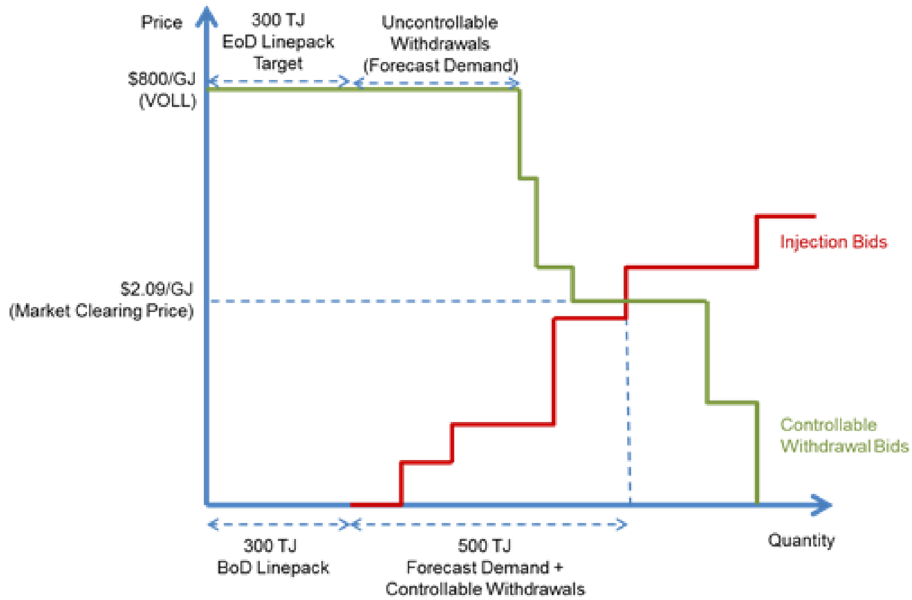
The key output in a pricing schedule is the ex ante market price. This market price is determined as follows:

- gas withdrawals (forecast demand plus controllable withdrawals) are met by the cheapest gas bids into the system, ie through a 'bid stack' process; and
- the market price is determined by the marginal price of the cumulative injection bid quantities that are required to meet the aggregate of all market participants' demand forecasts and controllable withdrawal bids.

Figure F.5 illustrates how the ex ante market price for a given schedule is determined in practice.

594 The exception is the last one-day ahead schedule where the data must be submitted by 10.00pm.

Figure F.5 Ex ante market price determination in the DWGM



Source: AEMC analysis.

In determining the pricing schedule, rule 221(3)(f) of the NGR requires AEMO to apply demand or supply point constraints to reflect limitations on pipelines or facilities that are external to the DTS. This is intended to ensure that external factors do not distort the market price.

However, in determining external demand or supply point constraints, rule 221(4) prohibits AEMO from taking into account operating conditions within the DTS. This is intended to ensure that any constraints on the DTS do not find their way into the pricing schedule. In this way, the pricing schedule remains "unconstrained."[595]

An administered price period may occur if the market has been suspended, a market price or pricing schedule is unable to be published by the required time or the cumulative price threshold has been reached. During this period the market price is capped at $40/GJ.

The cumulative price threshold is $1,800/GJ and is calculated as the marginal clearing price over the previous 34 scheduling intervals and the current scheduling interval.

595 In 2014, AEMO noticed that in practice, the pricing schedule does take into account operating conditions within the DTS when determining some supply or demand point constraints. The implications of the AEMO practice is that, in instances where injections to, or withdrawals from, the DTS are constrained, constraints are applied in both the pricing and operational schedules. We understand that this has the following effects: (1) The market price is increased (for constrained injections) or decreased (for constrained withdrawals) compared to an unconstrained pricing schedule; (2) The congestion pricing signals that would otherwise be provided through uplift payments are suppressed, potentially devaluing the benefits of AMDQ and AMDQ credits; and (3) Bids that are physically infeasible due to external constraints do not impact the market (this is in accordance with market design). We understand that AEMO proposes to implement a new operating practice whereby AEMO will apply all DTS constraints to the operating schedule only. This approach is compliant with the NGR and does not require a rule change. Further, we understand that AEMO intends to have the issue settled before winter 2015.

F.2.6 Imbalance payments

Imbalance payments are payments for the net difference between scheduled injections and withdrawals of gas by a market participant. Imbalance payments are determined on an ex ante basis.

In general, market participants endeavour to align their intended daily gas injections and withdrawals to avoid exposure to the spot market, unless the market participants are either sole injectors or withdrawers. However, intended daily gas injections and withdrawals may differ for a given day and market participants must pay the costs for the imbalance quantities in the form of daily imbalance payments, which can be positive or negative.

The imbalance payment for each market participant is calculated based on the imbalance quantities between their 6.00am scheduled daily injections and withdrawals at the 6.00am market price, plus the subsequent imbalance payment based on changes in the imbalance quantities at each reschedule priced at the reschedule price.

In summary, if a market participant:

- withdraws and injects the same quantity of gas over the course of the day the imbalance payment will be 0;
- withdraws more gas than it injects over the course of the day the imbalance payment will be positive (this implies that the given market participant has purchased gas from the gas market and must pay for the over-withdrawal to AEMO); and
- withdraws less gas than it injects over the course of the day the imbalance payment will be negative (this implies that the given market participant has sold gas to the gas market and is entitled to receive a payment from AEMO for the quantity of gas sold).

The Box 7.1 outlines how imbalance payments operate in practice.

Box F.1 Imbalance payments in the DWGM

Suppose a market participant has scheduled injection and scheduled withdrawal at the BoD schedule of 70 GJ and 40 GJ, respectively. Suppose also that as the day progresses, this market participant changes its injections and withdrawals at each reschedule as follows:

- 10.00am – scheduled injections remain at 70 GJ but scheduled withdrawals rises to 45 GJ;
- 2.00pm – scheduled injections remain at 70 GJ but scheduled withdrawals fall to 35 GJ;
- 6.00pm – scheduled injections fall to 50 GJ and scheduled withdrawals remain at 35 GJ; and
- 10.00pm – scheduled injections and withdrawals remain at 50 GJ and 35 GJ, respectively.

The calculation of the imbalances (in GJ), the change in imbalance (in GJ) and the associated imbalance payment is shown in the table below.

Schedule	Scheduled Injection (GJ)	Scheduled Withdrawal (GJ)	Market Price ($/GJ)	Imbalance (GJ)	Change in Imbalance (GJ)	Imbalance Payment ($)	Who Pays?
6:00 AM	70	40	$5.00	-30	NA	-$150	AEMO
10:00 AM	70	45	$6.00	-25	5	$30	MP
2:00 PM	70	35	$4.00	-35	-10	-$40	AEMO
6:00 PM	50	35	$4.00	-15	20	$80	MP
10:00 PM	50	35	$5.00	-15	0	$0	NA
Total Daily	-	-	-	-	15	-$80	AEMO

Source: AEMC analysis (based on AEMO training material).[596]

F.2.7 Deviation payments

Deviation payments are used to settle differences between market participants' scheduled and actual behaviour (ie market participants' actions compared to intentions). In contrast to imbalance payments therefore, deviation payments are calculated on an ex-post basis.

Market participants' deviations from their demand forecasts and scheduled quantities (injections and withdrawals) in a given schedule will have physical and financial impacts on the outcomes of the next schedule. For example, if a market participant under-forecasts their demand (or under-schedules injections) in the 6.00am schedule this will cause a decrease in linepack requiring more gas to be injected at the 10.00am schedule, and potentially an increase in gas market price. Likewise, deviations in the

596 AMEO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

10.00am scheduled quantities and demand forecasts will affect the 2.00pm market outcomes.

Deviation payments also provide market participants with a tool to trade linepack between schedules by managing their net positions in supply and demand.

The deviation quantity is calculated as the difference between the following for each market participant:

- actual withdrawals less scheduled withdrawals; and
- actual injections less scheduled injections.

Deviations are valued at the next schedule price because they can influence that price (eg, a deviation in 10.00am – 2.00pm interval is settled at the 2.00pm reschedule market price). Deviations in the last reschedule of the day are settled at the following 6.00am price.

Table F.1 outlines how deviation payments operate in practice, as well as the party responsible for paying the deviation payment.

Table F.1 Deviation payments in the DWGM

Schedule	Scheduled Injection (GJ)	Actual Injection (GJ)	Injection Deviation (GJ)	Scheduled Withdrawal (GJ)	Actual Withdrawal (GJ)	Withdrawal Deviation	Net Deviation (GJ)	Next scheduled market price ($/GJ)	Net deviation payment ($)	Who Pays ?
6:00 AM	30	28	-2	30	25	-5	-3	$5.00	-$15.00	AEMO
10:00 AM	35	36	1	30	30	0	-1	$6.00	-$6.00	AEMO
2:00 PM	35	50	15	30	31	1	-14	$4.00	-$56.00	AEMO
6:00 PM	20	22	2	25	18	-7	-9	$4.00	-$36.00	AEMO
10:00 PM	20	18	-2	15	16	1	3	$5.00	$15.00	MP
Total Daily	140	154	14	130	120	-10	-24		-$98.00	AEMO

Source: AEMC analysis (based on AEMO training material).[597]

F.2.8 Ancillary payments

It is not always possible to schedule the cheapest gas to meet the required demand for a given gas day. When the system is congested gas that is more expensive than the market price may be scheduled. Ancillary payments are compensatory payments to market participants who are affected by these events.

An example of when an ancillary payment would apply is on a high demand day in Melbourne. The gas used by customers during the gas day's peak period (evening) may exceed the amount of gas that can flow on the main pipelines into Melbourne In this case, LNG from the Dandenong LNG storage facility could be scheduled to be injected into the system to avoid breaching pressure limits on the pipeline, even if its price is well above the market price for that scheduling interval. Market participants supplying this LNG to the market would be paid the price they bid, rather than the lower market

597 AMEO, *An Overview of the Vic Gas Market (DWGM)*, workshop material, workshop given 23 January 2013 at the AEMC offices.

price.[598] The amount paid to these suppliers that is the difference between the bid price and the market price is known as an ancillary payment.

The Box F.2 outlines how ancillary payments operate in practice.

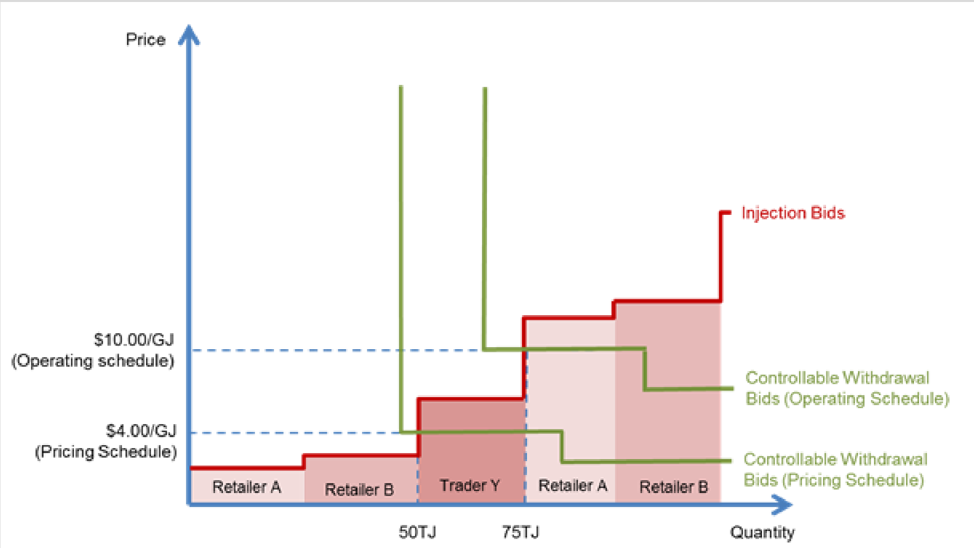
Box F.2 Ancillary payments in the DWGM

Suppose that AEMO has to call on an offer by a particular market participant's ('Trader Y') to inject 25 TJ of gas at $10/GJ in order to resolve a localised pressure constraint for a one hour period. At the same time, the market price is $4/GJ.

Trader Y will continue to receive the market price of $4/GJ for the 25 TJ they inject. However, they will be paid an ancillary payment for injecting the called upon 25 TJ at a price determined by the difference in the participant's offered price and the market price for that period, ie, $6/GJ (10-4). Trader Y will therefore receive the following:

- an injection imbalance payment of $100,000 (ie, 25,000 GJ x $4/GJ); and
- an ancillary payment of $150,000 (ie, 25,000 GJ x $6/GJ).

This is illustrated via the simplified depiction of the difference between the pricing and operating schedule below.



Source: AEMC analysis.

F.2.9 Uplift payments

Uplift payments are paid by market participants to fund ancillary payments, ie when payments are made to market participants who provide gas to (or withdraw gas from) the market at above the market price. To the extent possible, uplift is charged to market participants whose actions cause the ancillary payments.

There are four categories of uplift payments:

1. congestion uplift;

598 In other cases (albeit less likely), market participants may be scheduled to withdraw gas that is more expensive than their bid prices. This section will focus on injection ancillary payments.

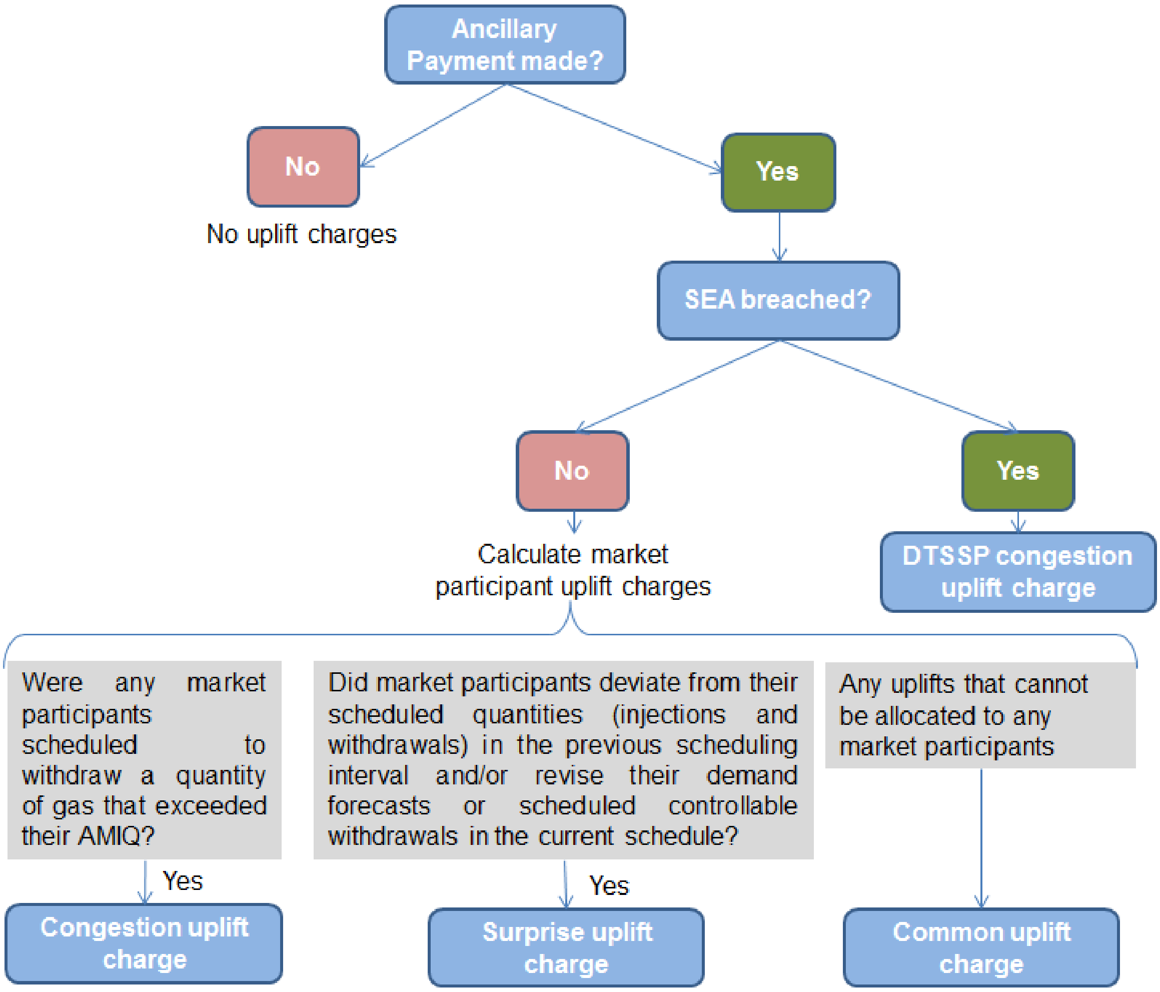
2. surprise uplift;

3. common uplift; and

4. Declared Transmission System Service Provider (DTSSP) congestion uplift.

The process for determining each of these uplift charges is outlined in Figure F.6 and discussed in more detail below the figure.

Figure F.6 Overview of the process for determining uplift charges



Source: AEMC analysis.

Congestion uplift charges are levied on a market participant if that market participant is scheduled to withdraw a quantity of gas that exceeds its Authorised Maximum Interval Quantity (AMIQ)[599] for that scheduling interval and the system is congested resulting in a positive ancillary payment. Allocations of congestion uplift payments are based on market participants' share of total congestion uplift quantity using detailed algorithms by AEMO.[600]

599 Each market participant's AMDQ uplift hedge is converted to schedule interval quantities using their nominated AMIQ profile (ie, how much AMDQ that participant expects to use in each schedule interval) to effectively create a hedge generated on an interval basis.

600 The AEMO algorithms for calculating a market participant's congestion uplift quantity are outlined at: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 92-94.

Surprise uplift charges are levied on market participants when they are considered to have taken actions to “surprise” the market in a way that increases costs. Specifically, a market participant is liable for surprise uplift if either or both of the following conditions are met during times ancillary payments had to be made:

- the market participant deviates from its scheduled quantities (injections and withdrawals) in the previous scheduling interval; and/or
- the market participant revises its demand forecasts or scheduled controllable withdrawals in the current schedule.

As with congestion uplift payments, allocations of surprise uplift payments are based on market participants’ share of total market surprise uplift quantity, calculated using detailed algorithms by AEMO.[601]

Common uplift payments include uplifts that cannot be allocated to any market participants via congestion or surprise uplift, for example costs associated with AEMO’s excessive demand forecast overrides.[602] Allocations of common uplift payments to market participants are based on their share of total system withdrawal quantities.

DTSSP congestion uplift payments are allocated to the DTSSP where it can be determined that the DTSSP has contributed to congestion by not making available the relevant plant and the associated pipeline capacity as required under the SEA (ie, the agreement it has with AEMO). For example, this could be due to additional congestion resulting from an unplanned outage of a critical plant where the outage can be attributed to lack of maintenance of the plant in accordance with the SEA.

F.3 DWGM rule changes

Section 295(3) of the NGL provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction. To-date all rule change requests have been made by AEMO and a summary of these is shown in Table F.2.

601 The AEMO algorithms for calculating a market participant's surprise uplift quantity are outlined at: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 90-92.

602 Prior to issuing the pricing and operating schedules, AEMO prepares hourly forecasts for uncontrollable withdrawals based on weather forecasts from the Bureau of Meteorology and compares these with the aggregate demand forecasts provided by all market participants. If they differ, AEMO determines whether to override the market participants' aggregate demand forecasts. See: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, p. 45

Table F.2 DWGM rule changes

Determination date	Rule change	Brief Description
11 December 2014	Removal of Force Majeure Provisions in the DWGM	Clarifies how the market is to operate in times of market stress, facilitating more accurate decisions and appropriate risk management practices.
27 November 2014	Portfolio Rights Trading[603]	The Commission determined not to make the proposed rule as a result of the following factors: revised cost of implementing Portfolio Rights Trading; revised estimate of the timeframe for implementing Portfolio Rights Trading; and the, then, forthcoming Victorian gas market review.
25 August 2011	Various Hedging Instruments in the Declared Wholesale Gas Market	• Allowed participants to renominate AMDQ and AMDQ cc between system injection points that are close proximity injection points during the gas day; • Allowed participants to renominate their AMIQ profiles during the gas day for future scheduling intervals in that gas day; • Provided participants ability to nominate injection hedges (IHNs) and agency injection hedges (AIHNs) collectively to close proximity injection points (CPPs) rather than to system injection points; and • Pushed back the timeframes for participants to submit IHNs, AIHNs and AMIQ profiles to AEMO so that they must be submitted by one hour before the start of the gas day.
4 November 2010	Calculation of Interest for Gas Markets	AEMO continue to calculate interest using a simple interest methodology.
16 December 2010	Dandenong Liquefied Natural Gas Storage Facility	Partially liberalised the operation of the Dandenong LNG storage facility.
20 May 2010	Prioritisation of Tied Controlled Withdrawal Bids	Changed the tie-breaking rules that AEMO uses to schedule gas so that, where multiple controllable withdrawal bids were considered to be "equally beneficial" to the market, controllable withdrawal bids would be prioritised over other bids if the bidder held AMDQ units. Previously, multiple controllable withdrawal bids considered to be "equally beneficial" to the market were scheduled on a pro-rated basis.

603 In short, a PRT mechanism was proposed to allow market participants to more readily carry out short term trades of the benefits attached to AMDQ and AMDQ cc, without changing the physical ownership of AMDQ and AMDQ cc or any curtailment rights associated with them.

F.4 DWGM Market Participants

Table F.3 lists the registered participants in the DWGM as at April 2015.

Table F.3 DWGM market participants

Shippers	Users
Adelaide Brighton Cement, AETV Power, AGL, Alinta, Aurora, Aus Gas Trading, Australian Pacific LNG, B P Australia, BHP, Boyne Smelters, Braemar Power Project, Coogee Energy, Covau, CS Energy, EnergyAustralia, ERM, Incitec Pivot, International Power, Lumo Energy, MMG Century, Momentum Energy, Mount Isa Mines, OneSteel, Orica, Origin Energy, Pelican Point, Qenos, QER, Queensland Alumina, Queensland Magnesia, Red Energy, Santos Direct, Simply Energy, South Australian Water Corporation, Southern Natural Gas Development, Stanwell Corporation, Synergen Power, Tas Gas, The Australian Steel Company, Visy Paper	ActewAGL, Adelaide Brighton Cement, AGL, Alinta Energy, Aurora Energy, B P Australia, BHP Billiton, BlueScope Steel, Bradmill, Click Energy, Commonwealth Steel, Covau, Delta Electricity, EDL CSM, Endeavour Coal, EnergyAustralia, Ergon Energy, ERM, GOEnergy, Lumo Energy, M2 Energy (T/As Commander Power), M2Energy (T/As Dodo Power & Gas), Momentum Energy, NovaPower, OneSteel, Orica, Origin Energy, Pentair Water Solutions, Qenos Pty Ltd, Red Energy, Santos, Simply Energy, Snowy Hydro, SOU Agent – TXU, Stanwell Corporation, Visy PaperPipee
Pipeline owners	**Producers**
Allgas Energy, Anglo Coal, APA, APT Petroleum, Ausnet, Australian Gas Networks, Bass Gas, Coastal Pipelines, East Australian Pipeline, Epic Energy, Gas Pipelines Victoria, Jemena, Multinet, SEA Gas, Tasmanian Gas Pipeline, The Albury Gas Co, Vic Gas	AGL, Australia Pacific LNG, BHP Billiton, Esso Australia Resources, Origin Energy, QGC, Santos, Woodside
Storage Providers	**Other**
AGL, APA, EnergyAustralia	Central Ranges Pipeline, Envestra, Australian Power and Gas, Newgen Power, CitiPower

Source: AEMO data.

G Operation of the Gas Supply Hub

G.1 History and policy objectives of the gas supply hub

In December 2012, SCER announced that a new voluntary brokerage hub would be established at Wallumbilla by March 2014.[604] SCER requested AEMO develop this hub to enhance transparency and reliability of gas supply by creating a voluntary market that offers a low-cost, flexible method to buy and sell gas at interconnecting transmission pipelines.[605]

Wallumbilla was selected as the location for the supply hub because it is located in close proximity to significant gas supply and demand and is a major transit point between Queensland and the gas markets on Australia's east coast. Wallumbilla marks the intersection of the Roma Brisbane Pipeline (RBP), the South West Queensland Pipeline (SWQP) and the Queensland Gas Pipeline (QGP).

The figure below illustrates how Wallumbilla acts as a transit point for major gas fields and a supply point for demand centres in Gladstone and Brisbane, and is located near gas storage facilities and gas-powered generation, making it a natural point of trade.

Figure G.1 Location of the Wallumbilla supply hub

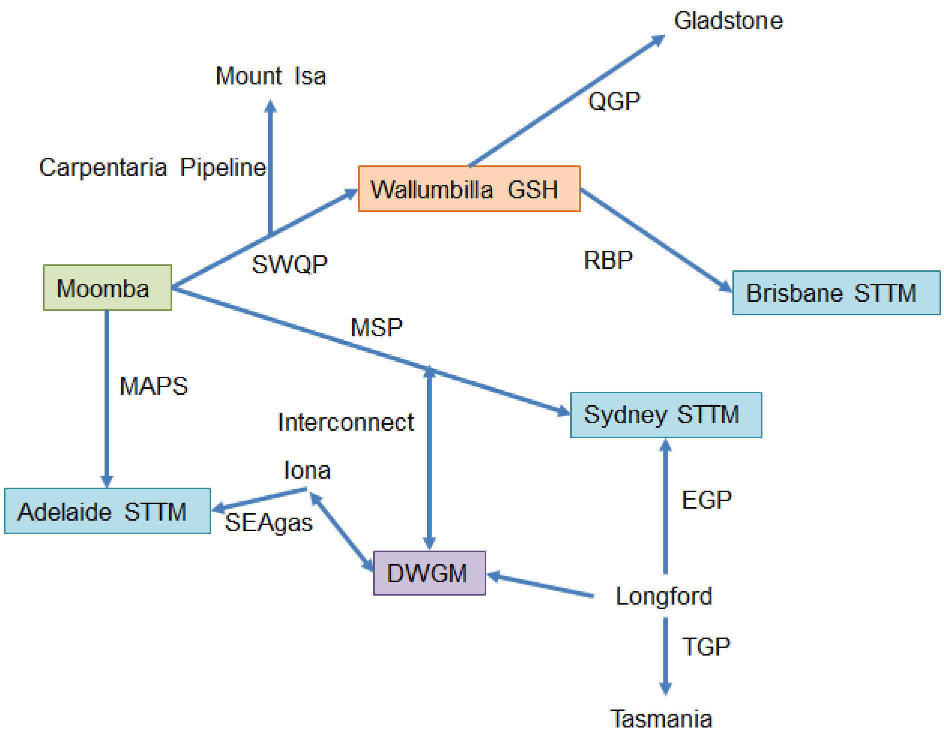
Source: AEMO, Gas Supply Hub Industry Guide, March 2014, p. 2.

An overview of how the three pipelines intersecting at Wallumbilla fit in with the east coast gas markets more broadly is shown in Figure G.2.

604 SCER Communiqué, 14 December 2012.

605 AEMO website, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub.

Figure G.2 Overview of the Wallumbilla supply hub and other east coast gas markets



Source: AEMC analysis.

AEMO was given the responsibility for the design of the hub and at the time of developing it stated that it expects the implementation of this hub to:[606]

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.

Overall, the supply hub was established to provide a reference price that would support a financial derivative market to manage risk, guide investment and transactions decisions, facilitate trading through standardisation of contracts, and promote secondary pipeline capacity trading.[607]

G.2 Design and structure of the gas supply hub

This section provides an overview of the design and structure of the Wallumbilla GSH. It covers how parties can participate in the GSH, the products currently on offer and the key design features.[608]

606 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p.4.

607 AEMO, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, p.4.

608 Unless otherwise stated, the information in this section references: AEMO, *Gas Supply Hub Industry Guide*, March 2014.

G.2.1 Participation in the market

To participate in the GSH an organisation must become a member of the exchange and register to as a participant in one, or more, of the following three categories:

1. Trading participant: authorised to place orders and form transactions through the exchange and can gain authorisation to enter into reallocations.[609]
2. Reallocation participant: authorised to enter into reallocations only. Can gain access to the exchange by registering in the category of viewing participant.
3. Viewing participant: authorised to view orders and transactional information through the trading exchange. Does not have any trading or financial involvement in the market.

Trading participants and viewing participants have access to the exchange and can view prices and quantities of active orders and recent transactions.

Participants must also provide sufficient bank guarantees to cover the market's exposure to their trading activities and a member's trading limit is equal to the bank guarantees provided. Participants are not permitted to share collateral between other markets that AEMO operates and a new bank guarantee is required for the GSH.[610]

G.2.2 Products

Products traded are for physically delivered gas, the terms of which include a warranty that the transacting parties have the necessary rights at the delivery point to give effect to the delivery and receipt of the gas.

Specifically, products listed on the exchange are for the sale and purchase of gas delivered at one of the three major connecting pipelines at Wallumbilla, ie the RBP, the QGP and the SWQP pipelines (as outlined in Figure G.2 above). A "trading location" has been established for each of these pipelines by grouping delivery points (either physical or virtual) to which gas is delivered and where title is transferred from a seller to a buyer.

The four trading products currently on offer are summarised in Table G.1. All products are currently available separately for each of these three trading locations.

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609 A reallocation is a financial arrangement between two market participants and AEMO to transfer settlement commitments between the market participants.

610 AEMO, Gas Supply Hub Frequently Asked Questions, available at: http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/FAQ

Table G.1 GSH trading products

Product	Trading Window	Gas Delivery
Balance-of-day (today)	Available for trading on the gas day. Delivery of gas occurs from the hour after the time of the transaction through to the end of the gas day.	Each individual transaction must be delivered
Day-ahead (tomorrow)	A gas day product that is available for trading on the day prior to the delivery gas day.	
Daily (two to seven days ahead)	A gas day product that is available for trading between 2 and 7 days prior to the delivery gas day. All other specifications for the product are same as the day-ahead product except that netting is applicable (as described in G.2.3 below).	Delivery obligations are netted.
Weekly (next four weeks)	Trading commences on a Saturday four weeks prior to the commencement of the weekly delivery period. Trading closes on the Friday (2 days) prior to the prior to the commencement of the weekly delivery period.	

Source: AEMO, *Gas Supply Hub Exchange Agreement*, Version No. 2.0, 13 April 2015.

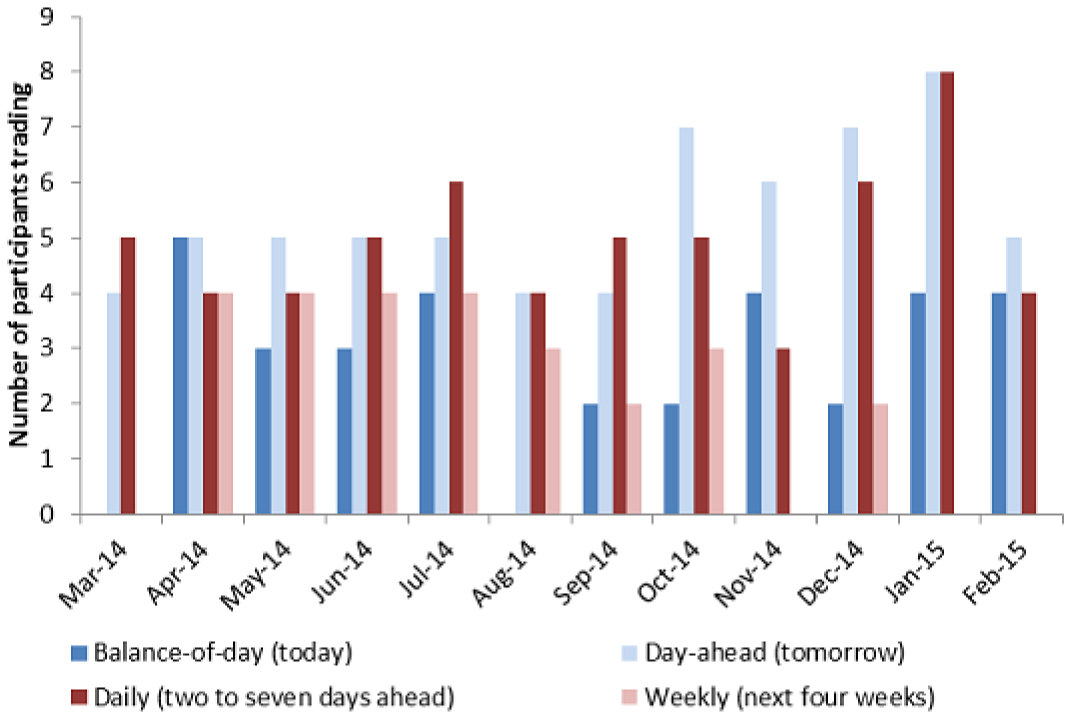
Note: We understand from AEMO it is also intending to list a monthly forward dated product later in 2015.

These products are available on a short-term basis and provide trading participants with an option for balancing their gas portfolio requirements around long-term agreements. The transaction quantity for all products, including balance-of-day and weekly, is measured as a quantity per gas day (GJ/day). Minimum quantities for the product are detailed in the product specifications contained in the exchange agreement. Unless otherwise agreed between the parties, gas delivery is at a constant hourly flow rate for the period of a transaction.

Trading participants also have the opportunity to trade capacity, which is facilitated by the exchange. Specifically, the exchange includes a capacity listing service but actual capacity-related transactions must be bilaterally negotiated and settled.

Figure G.3 illustrates the monthly trade activity on the Wallumbilla supply hub by product, since market start.

Figure G.3 **Monthly trade on the Wallumbilla supply hub by product, March 2014 – February 2015**



Source: AEMC analysis on AER, Wholesale Statistics.

G.2.3 Key design features of the Wallumbilla supply hub[611]

This section details the key design features of the Wallumbilla GSH. It covers: the exchange agreement; how gas is traded; the concept of delivery netting; settlement; delivery variances; the lack of physical connection at the hub; and market fees and participant costs.

Exchange agreement

In accordance with the NGR, the supply hub has an "exchange agreement" that sets out the standardised terms of participation in the supply hub and the terms governing transactions entered into through the exchange. The exchange agreement contains the trading, delivery and settlement obligations common to all products. It also outlines the product specifications, which are schedules to the exchange agreement that contain details unique to each product.

The NGR itself contains relatively little detail on the GSH, compared to the STTM and DWGM. The NGR covers: the fees recoverable by AEMO; the appointment of an operator by AEMO; how payments are determined; membership and participation; the exchange agreement; and the market conduct rules.

611 Unless otherwise stated, the information in this section references: AEMO, Gas Supply Hub Industry Guide, March 2014.

Trading of gas

Participation in the supply hub is voluntary and designed to complement existing bilateral gas supply arrangements and gas transportation agreements. Trades are matched anonymously, although there is also a facility for participants to agree bilaterally to a transaction on standard product terms and then register the transaction for delivery and settlement. This allows participants a lower transaction costs option for trading gas and also allows the counterparty risk to be lowered.

In transacting on the exchange the seller commits to supply gas at the trading location and the buyer agrees to take receipt of that gas at the trading location.

Trading hours are between 9.00am to 5.00pm on the Wallumbilla GSH and the gas day start time on the Wallumbilla GSH is consistent with the Brisbane STTM hub (8.00am).

Within a trading location, there may be multiple delivery points.[612] Once transacted, the delivery points specified in the trade will be the location for gas delivery. Participants are responsible for arranging the delivery of gas at the hub using existing contractual supply and transportation agreements. The pipeline operator schedules the delivery of gas at the trading location based on nominations submitted by participants.

Delivery netting

As noted in section G.2, a delivery netting service is provided for all products traded more than one day from delivery. Rather than deliver gas against each individual transaction, delivery netting produces a single net gas delivery obligation for each trading participant across their relevant transactions. Netting applies to gas delivery obligations only and all transactions must be financially settled.

Delivery netting involves AEMO determining the net delivery position for each participant at the end of trading. AEMO then matches participants with offsetting delivery positions based on an algorithm that minimises the number of transactions that need to be delivered.[613]

A simplified overview of how the concept of delivery netting operates in practice is outlined in Box G.1.

612 Delivery points are virtual points or at a junction on the QGP, RBP and SWQP.

613 AEMO, *Detailed design for a Gas Supply Hub at Wallumbilla*, 19 October 2012, p. 21.

Box G.1 Delivery netting

Suppose there are three market participants that conduct the following trades with one another:

- Trade 1: Participant A buys 5 TJ from Participant C;
- Trade 2: Participant C buys 15 TJ from Participant B; and
- Trade 3: Participant B buys 5 TJ from Participant A.

AEMO would then offset buy and sell exchange transactions to determine a net delivery position for each participant as follows:

Trade	Participant A	Participant B	Participant C
1	5 TJ	-	-5 TJ
2	-	-15 TJ	15 TJ
3	-5 TJ	5 TJ	-
Net delivery	Zero	Sell 10 TJ	Buy 10 TJ

AEMO determines each trading participant's net delivery position by aggregating buy and sell transactions across all netted products for each trading location and gas day.[614] AEMO matches net buy and net sell positions to form a gas delivery schedule. Trading parties remain anonymous until the gas delivery schedule is issued by AEMO to participants.

The netting of gas delivery obligations eliminates the requirement to deliver offsetting delivery obligations (delivery and receipt) that could act as a hurdle to efficient portfolio management. Delivery netting also reduces the administration associated with nominations, measurement and communication of actual gas deliveries.

Settlements

The Wallumbilla GSH features a centralised settlement model to settle transactions with AEMO facilitating payments from buyers to sellers. This involves collating transactional information from the trading system, collating delivery information from trading participants, calculating settlement amounts, and issuing statements.

As noted earlier, market participants must maintain credit support to cover the exposure associated with their transactions.

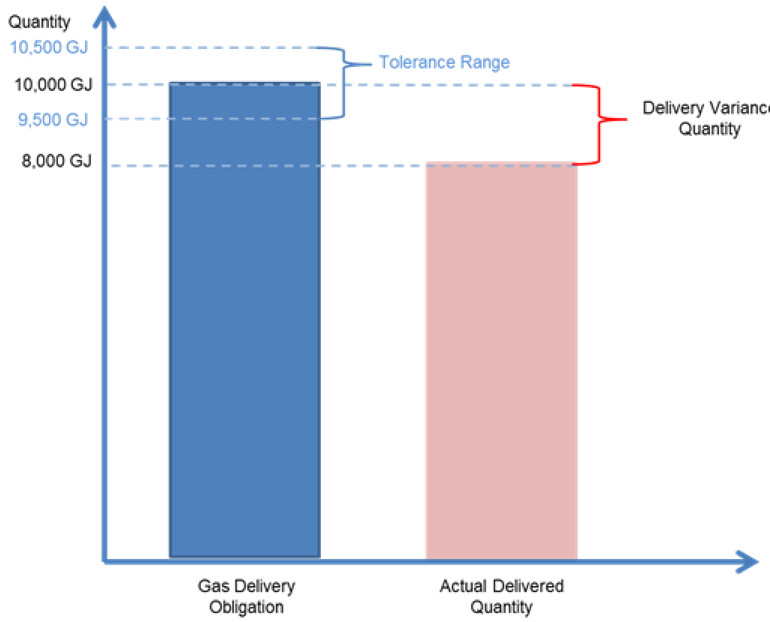
614 The delivery netting process runs every day after the end of trading. Transactions covering the gas day two days in the future are retrieved for the calculation of the net delivery position. AEMO will determine each trading participant's net delivery position and then match those net delivery positions amongst participants to form a delivery schedule. AEMO will then issue a gas delivery schedule to trading participants so that they can carry out their gas delivery obligations.

Settlement of delivery variance

'Delivery variance settlement' is a procedure that AEMO administers to facilitate the transfer of compensation between the buyer and seller for a variation between the gas delivery obligation and the actual delivery.

AEMO defines a tolerance for variations in actual delivered quantity of 5 per cent of the gas delivery obligation (for both the over- and under-delivery of gas). Figure G.4 illustrates this using an example where the seller (delivering participant) is not able to deliver the contract quantity and the delivery variance quantity is outside the permitted tolerance.

Figure G.4 Delivery variance



Source: AEMC analysis.

Regardless of whether the delivery variance quantity is outside of the tolerance, the delivery variance quantity is settled at the delivery price. The delivery price is dependent on the whether netting is applicable to the gas delivery obligation:

- average price for netted products (as outlined above), or
- transaction price if product is not netted.

Additionally, if the delivery variance quantity is outside the tolerance then the settlement is adjusted so that the defaulting party compensates their counterpart. The party at fault compensates their counterpart for 25 per cent of the value of the variation quantity.[615]

In determining the party at fault, AEMO considers the reason for the variation, eg:

- a gas producer (delivering participant) may have failed to inject gas into the pipeline in accordance with their gas delivery obligation – the delivering participant was responsible for the delivery variation; or

615 No adjustment is processed if force majeure (pipeline issue only) applies to the delivery failure.

- a shipper (receipting participant) may have failed to make nominations to the relevant pipeline operator in accordance with their gas delivery obligation – the receipting participant is responsible for the delivery variation.

An example of how this compensatory mechanism works for delivery variance quantities outside of the tolerance range is illustrated in Box G.2.

Box G.2 Delivery variance quantities - compensatory mechanism

Suppose that Figure G.4 above represents a situation where Trader A has agreed to sell 10,000 GJ of gas to Retailer X at a price of $6/GJ. Under this hub transaction, Trader A will receive a transaction payment of $60,000 from Retailer X.

However, suppose that Trader A (ie the seller) is not able to deliver the entire contract quantity to Retailer X (ie buyer). Specifically, receipt point allocation for Retailer X is 2,000 GJ lower than its nomination and so Trader A must pay back for the gas it did not deliver to the hub. This delivery variance charge is calculated as:

- $12,000 (ie 2,000 GJ x $6/GJ).

Further, given the delivery variance of 2,000 GJ is outside of the 5 per cent tolerance (ie 500 GJ), Trader A must make pay delivery variance charge to Retailer X. This is calculated as:

- $3,000 (ie 2,000 GJ x $6/GJ x 25 per cent).

Overall, Trader A is paid a total of $45,000 by Retailer X for the 8,000 GJ it delivered to the hub (or, equivalently $5.625/GJ). This is calculated as:

- Hub transaction payment less delivery variance charge less delivery variance compensation, ie $60,000 - $12,000 - $3,000.

The delivery payment and charge settlement mechanism is the only remedy available for a breach of a participant's delivery obligations. The fixed compensation mechanism may under or over compensate a participant for their actual direct costs associated with the delivery default. However, the fixed compensation mechanism provides certainty of the trading risks to participants prior to entering into a hub transaction and is simpler to administer than the determination of damages on a transaction by transaction basis.

Lack of physical interconnection

As noted above, the Wallumbilla supply hub has three physical trading locations which are the RBP, SWQP and the QGP. While these pipelines are connected, they operate under different pressures and contractual arrangements by two pipeline owners (ie Jemena for QGP and APA Group for RBP and SWQP). As such, there is no single physical location that allows shippers to trade across the Wallumbilla hub.[616]

The fact that not all of the pipelines servicing Wallumbilla are physically connected was a reason why AEMO developed three separate trading nodes at Wallumbilla.[617]

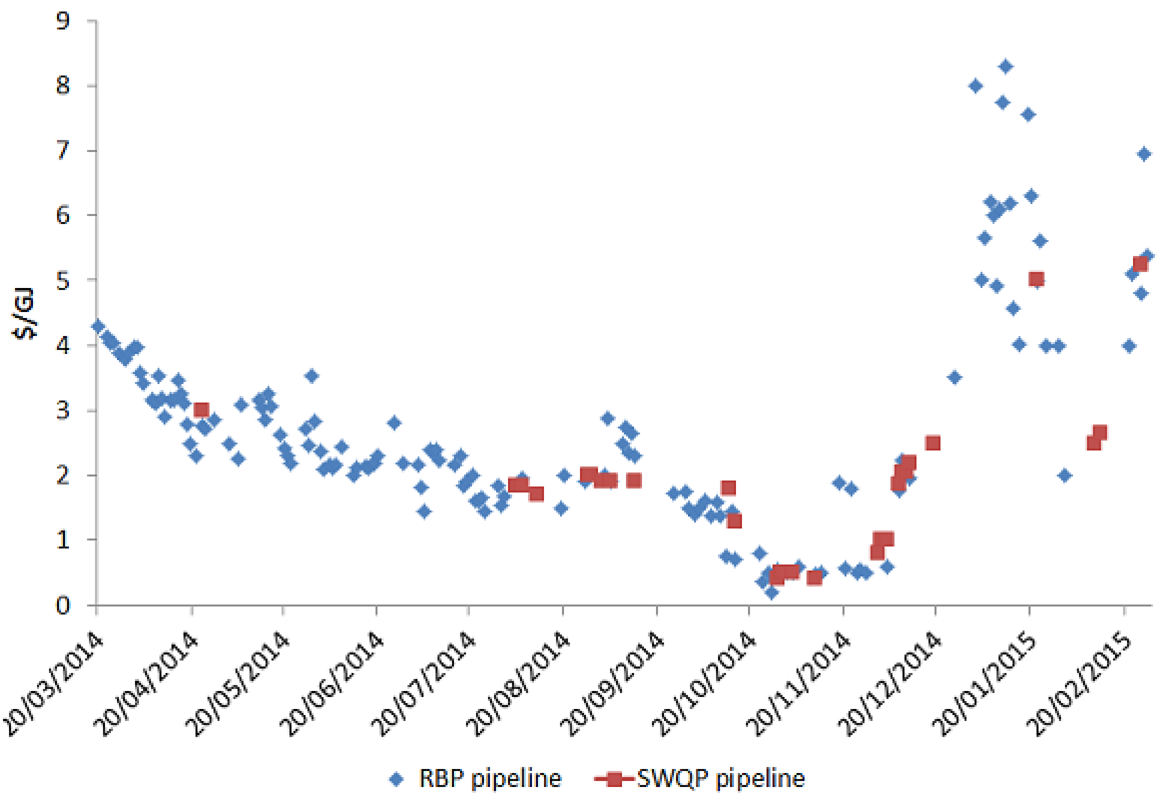
616 AEMO, *Gas Supply Hub: Cost and Scoping Report,* May 2012, p. 18.

617 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, p. 62.

The lack of physical interconnection, coupled with the fact that only a few participants are currently in a position to transport gas between the trading nodes (ie because they have the necessary transportation and ancillary services contracts in place), means that the pool of potential buyers and sellers is divided across the three trading nodes. The division of what is already a relatively small group of buyers and sellers limits the degree of liquidity that can be achieved in the market and could also give rise to significant price variations across the three trading nodes.[618]

While we note that the vast majority of trades to date have occurred at the RBP node,[619] as can be seen in Figure G.5 those trades occurring at the SWQP node do not appear to be significantly different to those at the RBP node. However, this is not to say this will continue to be the case, particularly as trades emerge at the QGP pipeline. Further, the pattern of prices in the period following the first exports of LNG from Queensland in late 2014[620] differs notably from the period preceding these exports.

Figure G.5 Majority of trades have occurred to date at the RBP node



Source: AEMC analysis on AER, Wholesale Statistics.

AEMO is aware of this potential limitation and has noted it could, to some extent, be addressed if the brokerage model was extended to include a new range of hub services that would enable parties that do not currently have the contractual rights to transport

618 K Lowe Consulting, *Gas Market Scoping Study*, a report for the AEMC, July 2013, pp. 62-63.

619 We understand that most trades have occurred at the RBP delivery point with trading between participants who have excess gas from gas-fired generation selling to opportunistic buyers who have the capacity to transport and store this excess gas.

620 BG Group began loading its first LNG cargo from QCLNG on 28 December 2014. See: QGC website, available at: http://www.qgc.com.au/news-media/NewsDetails.aspx?Id=5630.

gas across the hub to do so. The two hub services that AEMO has identified as being of particular importance in the initial stages of the supply hub's life are redirection and compression services. Other hub services AEMO has noted could evolve over time are balancing, storage and processing services.[621]

Market fees and transaction costs

Trading, reallocation and viewing participants are required to pay a fixed participation fee, determined in accordance with their participation category. These annual fees are currently, $14,500, $9,000 and $5,500 for trading, reallocation and viewing participants, respectively.[622]

Trading participants are also required to pay a variable transaction fee based on the quantity of transactions they enter into through the exchange. These variable transaction fees are currently $0.03/GJ for daily products and $0.02/GJ for weekly products.[623]

621 AEMO, *Gas Supply Hub – Cost and Scoping Report*, 4 May 2012, p.14.

622 AEMO, *Gas Supply Hub – Exchange Fees*, 20 March 2014, p. 1.

623 AEMO, *Gas Supply Hub – Exchange Fees*, 20 March 2014, p. 1.

H Submission Summaries

Table H.1 Submission summaries

Stakeholder	Comment
	Markets: complexity and cost
Adelaide Brighton, pp. 2-3	STTM has reduced average cost of gas for large users by allowing users to use a portfolio approach to procurement. Intraday trading would add to costs. Gas users can adjust nominations and use MSVs to balance position, which negates need for intraday trading.
Adelaide Brighton, p. 4	More work should be performed on determining whether to remove the DWGM and establish an STTM in Melbourne.
Adelaide Brighton, p. 3	Intraday trading in the STTM would be of limited benefit to customers and would increase the level of resources required to participate in the STTM.
AGL, p. 1	Complexity and transaction costs overwhelm any value to be had from trading in the STTM facilitated markets. Simplification is required, eg consideration should be given to dispensing with the pricing functionality in the STTMs and relying on physical balancing and correct nominations by participants (with penalties for material deviations).
AGL, p. 3	Wallumbilla gas supply hub has facilitated short-term trades in gas by eliminating the overheads of contractual and term sheet negotiations associated with spot transactions.
AGL, p. 5	The DWGM is best left unchanged, as the costs associated with change are likely to outweigh the benefits. Nevertheless, as there is significant complexity and risk in ancillary payments and uplift charges, AGL would welcome a review of these charges with the aim of reducing market participants' transaction costs and pricing risks.
Alinta, p. 6	Alinta does not expect the construction of additional hubs such as Moomba to materially change the nature of trading activity in the area. However, there is some contention that trading hubs may not actually be needed if existing transport costs were not so excessive or if alternate market structures such as a carriage arrangement were in effect.

Stakeholder	Comment
Alinta, pp. 5-6	Alinta is supportive of the review investigating what benefits could be revealed through longer term options such as increased integration between facilitated markets and whether three distinctly separate gas markets remains fit for purpose given the relatively small volume of gas traded. Regardless, there are areas that are worthy of resolution now: • greater alignment of market parameters between facilitated markets; • common gas day; and • prudentials.
Alinta, p. 8	Transactions costs are high due to contractual and administrative burdens associated with trades involving gas pipelines.
Alliance of industry associations, p. 7	Within the alliance of industry associations, an individual association suggests streamlining and simplifying the STTM registration process to encourage more participants.
APA, pp. 9-10	The STTM design is overly complex for the primary gas balancing function it performs. The complexity inherent in the STTM drives significant market operating costs and there is little evidence of additional retailers entering the market. The STTM should be simplified to be a balancing market that provides for competitive balancing services through a tender process.
Arrow Energy, pp. 7, 8	Australian gas markets are currently disparate, creating inefficiencies or hurdles to transacting. Arrow is of the opinion that a single market structure dealing with all transaction elements, from production to use, is critical. Impediments to participation include: market inconsistencies, complexities and costs; lack of physical pipeline interconnection and access to transportation capacity in some areas; the continued prevalence of longer term contracts (usually bespoke); lack of standardised contract terms; and basis risk resulting from differing market dynamics.
Australian Energy Regulator, pp. 2-3	Accuracy and timeliness of data and demand forecasts in the STTMs shortly after to their commencement led to ad hoc outcomes and inefficient prices. More recently, the AER has reported significant improvements in these areas.
Australian Energy Regulator, p. 3	Ongoing monitoring work by AER is lowering costs in the STTM.

Stakeholder	Comment
Australian Petroleum Production & Exploration Association (APPEA), p. 3	Recommends investigation of means to more closely align facilitated markets.
Australian Pipelines and Gas Association (APGA)	APGA considers that the STTM hubs do not deliver value to market participants. Internal costs incurred by market participants in setting up and managing systems to interact with the STTM, in addition to the 8c/GJ transaction costs present a burden for participants. The STTM and DWGM are primarily balancing markets, designed to complement, not inform or replace, long term contracting arrangements. The prices in these markets are not commodity supply price, rather the price of the imbalance on the day, in that market. There are opportunities for improved integration across the markets, such as harmonising: • gas day start times; • price caps; and • terminology. Further, counteracting MOS in the STTM arises because the STTM is assumed to not have physical limitations to delivering gas to Sydney and Adelaide. APGA contend this is not a design fault, but rather a price signal for change and further investment. APGA is also concerned about the inability of the market operator to correct STTM prices in the event of pipeline information error or failure.
BHP Billiton, p. 2	Reform initiatives should be harmonised across all states (by leveraging AEMO's processes, systems and implementation experience).
ESAA, p. 1	A key area for consideration is how to minimise the costs and risks associated with participating in the facilitated trading markets.
ESAA, pp. 3-4	Facilitated markets provide participants with access to gas in the initial phase of market entry. But long-term contracts for gas supply and transportation (outside of the facilitated markets) are ultimately required to manage the significant price risk associated with operating in those markets. The ability of market participants (and new entrants) to rely purely on the facilitated markets for gas supply will continue to be impeded while they create significant price/supply risk.

Stakeholder	Comment
ESAA, p. 4	Differences between the DWGM and STTM can potentially increase costs for participants operating across multiple jurisdictions. There is merit in examining: • the creation of a single gas day; • the consolidation of prudential requirements; and • harmonisation of gas market parameters.
ESAA, p. 5	The facilitated markets are quite costly on a $/GJ traded basis.
EnergyAustralia, p. 2	The three fundamentally different types of facilitated market need to be better aligned (although this is not to say that a single approach is necessarily required).
Epic Energy, p. 2	The STTM and DWGM are balancing markets and should not be considered wholesale markets. The DWGM and STTM price reflects the value of imbalance in the market and not the value of gas for that region, especially in the South Australian hub where power generation loads are excluded.
ERM Power, p. 7	The DWGM has complex elements, which reduces information transparency and ability to manage trading positions and market outcomes. Efficiency could be improved by harmonising gas day start times.
ERM Power, pp. 9-10	ERM questions the net benefits of introducing a single trading zone/single product model.
ERM Power, p. 10	The minimum parcel size at Wallumbilla may prevent smaller participants from trading. GSH fees are also too high and should be reduced.
GDF Suez Australian Energy (GDFSAE), pp. 8-10	The existence of multiple hub designs creates complexities and inefficiencies. While the WGSH is purpose built and continues to evolve, the remaining facilitated hubs require more development to manage challenges facing the market and to facilitate the optimal level of trade outside of bilateral contracts. Areas for investigation are: • rationalising market design; • coordinating dispatch;

Stakeholder	Comment
	• using clear, understandable within day charges and better management of ex-post pricing; • better use of balancing and maximising trade; • signalling the value of capacity and services inside hubs; • more efficient price signals; • limiting the role of pipeline and facilities within hubs; • consolidating prudential regimes; • developing gross indices; • facilitating financial trade at Wallumbilla; • identifying preferred conditions for the Moomba Gas Supply Hub; • auctioning capacity credits; and • the use of backhaul for the purposes of calculating pipeline capacity.
Group of leading energy companies and major users (GLECMU), p. 1	A challenge today is the fragmented nature of Eastern Australian gas markets, including existing trading and capacity arrangements, and the difficulty in establishing an agreed and coherent framework that best meets the needs of the market.
GLECMU, p. 3	Multiple market designs make trading complex and inefficient for participants with each market characterised by specific and enduring limitations.
Lumo Energy, pp. 3-4	Markets are allowing transactions to occur and are operating satisfactorily. While there may be some minor changes that are required, major changes need to demonstrate a clear case for being made.
Lumo Energy, pp. 3-4	There are no real barriers to entry to using the wholesale markets. While adding an intraday trading mechanism would add cost and complexity, it would provide market participants with an avenue to improve the manner in which they manage their deviations of the trading day.
Lumo Energy, pp. 9-10	Supports the development of a single product at Wallumbilla. This will facilitate the development of longer term trading products, which Lumo supports.

Stakeholder	Comment
Major Energy Users, p. 6	Facilitated markets are complex, but complexity can result from attempting to ensure markets operate in long term interests of consumers.
Manufacturing Australia, p. 6	A functioning market should have more suppliers, as well as more gas supply. Transparency and opening of the domestic market to competitive functioning is imperative to restoring confidence in the market.
Origin, pp. 4-5	There is no need to harmonise the markets under one single design. There is, however, possible scope to coordinate certain elements: • harmonise gas days, including with reference to the NEM day; • netting prudential requirements; • coordinating market parameters (eg, market price cap); and • formulation and presentation of information.
Qenos, p. 4	Gas Supply Agreements would be more easily made if information were centralised and more easily accessed.
Qenos, p. 5	Allowing for the full settlement of Markets Schedule Variations (MSV) through the STTM Settlement System would negate the need for individual parties to put in place separate documentation with every other market participant for MSV transactions. It would negate the need for credit checks and credit support arrangements between individual market participants for MSVs.
QGC, p. 6	There is a lack of harmonisation across facilitated markets of key features including trading day definition, consistency of trading periods and settlement processes.
Santos, p. 1	Standardisation of facilitated markets would reduce costs, barriers to entry and basis risk among regions. It would facilitate more players in the market and hence a more liquid secondary market. Consideration should be given to standardising all balancing markets so there is one model across all regions. Santos agrees with a number of other alignments, such as standardisation of the gas day and minimum market price caps.
Stanwell Corporation, pp. 1-2	A well-functioning east coast gas market could be modelled on the NEM. This could feature the following characteristics:

Stakeholder	Comment
	• Participants providing injection and withdrawal bids to AEMO. • Gas volumes scheduled by AEMO. • AEMO calculating and publishing gas prices at regular intraday intervals. • Transportation costs estimated by AEMO in advanced and charged to shippers. • Gas pipeline investment and revenue regulated by the AER and buyers pay usage charges based on consumption. • AEMO operating a separate balancing market based on offers to provide balancing services by participants and pipelines, with the cost recovered from consumers. • New producers or consumers connecting to the transmission or distribution network through a connection agreement rather than through specifying a pathway.
Stanwell Corporation, p. 4	Complexity and cost of operating under various market arrangements is a barrier to entry.
Markets: liquidity	
Epic Energy, p. 4	Epic Energy support the introduction of a trading location at Moomba and considers it would provide a more transparent market place to non-Queensland market participants.
Adelaide Brighton, p. 2	Facilitated markets improve liquidity, providing an additional option for procuring gas.
AGL, p. 2	The physical configurations of the individual hubs are not consistent with the fundamental assumption made when the STTM markets were designed (that there are no or minimal network constraints within the distribution network). The existence of phenomena such as counteracting MOS suggests that this assumption does not hold under all circumstances and flow situations.
AGL, p. 3	STTMs require that the ex ante price and scheduled offers are locked down some 18 hours before the start of the gas day. Deviations are the result of changing conditions from that time. However, AGL would caution against intra-day renomination functionality, given its complexity. Instead, a MOS balancing service, and participants engaging in MSV trades may be appropriate.

<table>
<tr><th>Stakeholder</th><th>Comment</th></tr>
<tr><td>Alinta, p. 7</td><td>Alinta is interested in exploring (as a long term policy option) a market carriage type arrangement with a single gas market with regional nodes (not dissimilar to the power market).</td></tr>
<tr><td>Alinta, p. 8</td><td>The market does not currently cater for short-term trades.</td></tr>
<tr><td>Alliance of industry association, pp. 6-7</td><td>Gas market solutions must reflect the full range of identified market-based reforms for the gas market, including:
consideration of a transitional national mechanism to require all stages of the gas value chain that have capacity available to provide an offer to the domestic market;
establishment of a daily balancing mechanism for the gas wholesale markets, as occurs in the electricity market; and
fast tracking the Moomba Gas Hub to facilitate the supply of gas by junior producers.</td></tr>
<tr><td>Alliance of industry associations, p. 7</td><td>Within the alliance of industry associations, individual associations suggest:
incorporating MSV trading in the STTM in preference to intra-day trading;
a requirement for AEMO to balance the east coast gas market on a daily basis so that there is no NSW shortfall;
the development of a gas supply hub at Moomba; and
the development of a liquid forward market.</td></tr>
<tr><td>APA, pp. 18-19</td><td>APA supports the development of hub services at Wallumbilla to improve liquidity of the market, and is currently working with AEMO and other participants on the design of those services (to allow trading across the three pipelines and integration of the three trading nodes into a single point).

Before proceeding with development of a second hub at Moomba, the impact on liquidity at Wallumbilla should be properly assessed.

APA considers there may be merit in exploring options for a consistent market design across eastern Australia that would support trade across all markets. The design would rationalise existing structural elements into two key arrangements:
gas supply trading at gas supply hubs located at natural trading points; and</td></tr>
</table>

Stakeholder	Comment
	• simplified market based balancing at demand centres.
Arrow Energy, p. 9	The WGSH has delivered improved liquidity. A more important benefit is the development of a transparent pricing point.
Arrow Energy, p. 9	Trading at RBP can impact trading on the STTM and vice versa.
Arrow Energy, p. 9	There are possible advantages and disadvantages to introducing the Moomba supply hub. It would add price transparency on hub transfer services and would identify constraints on any interconnected pipelines. However, multi nodal markets generally adversely impact liquidity.
AEMO, p. 2	A GSH at Moomba is likely to provide participants with more trading options and, in turn, more liquidity in the secondary capacity trading market.
Australian Energy Regulator, p. 3	Occurrences of counteracting MOS may reveal Adelaide STTM design issues, justifying further investigation.
Australian Pacific LNG, p. 2	Supports the development of a more liquid wholesale spot and forward gas market. This may be facilitated by: greater consolidation and alignment in market design across regions; improved transportation access, including standardised terms; development of a daily reference gas price; development of longer term traded products including futures; development of additional hub services including balancing and pooling.
APPEA, p. 2	Relatively small size of the east coast gas market by international standards has historically placed limitations on the liquidity and complexity of gas markets.
APGA	Transmission pipelines have an important role in developing liquid, transparent and competitive wholesale markets, however further regulation is not the 'silver bullet' to further development of the markets. APGA considers that there are insufficient market participants to underpin a liquid and flexible eastern Australian gas market and additional Government intervention (and associated complexity) is not warranted.
BHP Billiton, p. 2	The market in eastern Australia continues to be dominated by long term confidential bilateral transactions. Increased market transparency and liquidity will improve the market’s ability to respond more rapidly to market developments and to send timely signals to encourage a response. BHP Billiton supports the current market reform initiatives that are being progressed across Australian gas markets.

Stakeholder	Comment
BHP Billiton, p. 2	Supports the concept of transitioning or complementing the STTM and the Victoria spot market with a common supply hub model to promote the development of wholesale market liquidity. Hurdles to development include: • the small size of the market compared to international markets; and • barriers such as the complexity associated with entering the existing Victorian imbalance market.
ESAA, pp. 3, 5	To improve trading and liquidity and ensure the facilitated markets deliver value to market participants in the future, reducing transaction costs and minimising the pricing risks associated with participation is essential.
ESAA, p. 5	The Brisbane hub suffers from structural limitations. This includes: a reliance on a single transmission pipeline; the inability to purchase gas from the hub unless a transportation contract on the pipeline is held; and the market design assumption that there are no constraints within the hub when this is clearly not the case. The evolution of the Wallumbilla GSH could further diminish the value of/need for the Brisbane hub in the future.
ESAA, p. 6	A Moomba GSH has the potential to facilitate improved participation and liquidity.
EnergyAustralia, p. 3	Supports the GSH at Moomba as a potential immediate priority. Lessons from Moomba and Wallumbilla should inform the Commission's wider analysis.
EnergyAustralia, p. 3	Review should focus on opportunities to align producer nomination times and market schedules, options to enhance intra-day flexibility, and the interaction between gas and electricity markets.
ERM Power, p. 9	While establishing a GSH at Moomba may reduce liquidity at Wallumbilla, the benefits of establishing a GSH at Moomba outweigh these costs.
GDFSAE, p. 2	Market liquidity and the opportunity to manage risks arising through market participation do not match participants' interests. The reasons for this include absence of integration, historical hub-by-hub developments, markets overly influenced by physical limitations, high entry and transaction costs, and focus on bilateral contracts and contractual strictures.

Stakeholder	Comment
GLECMU, p. 3	Hubs should be designed to facilitate participation and liquidity. Presently, hub characteristics and design leads to a situation where gas retailers are likely to participate, with gas producers, industrial and commercial users and pipelines typically outside of these arrangements, and intermediaries choosing not to participate.
GLECMU, p. 3	Within day price signals, trading day definitions, consistency of trading periods, and settlement processes should be set so as to facilitate trade and support a more liquid market including encouraging the development of forward products.
Lumo Energy, p. 6.	Intraday trading in the STTM would provide significant benefits to the market.
Lumo Energy, pp. 10-11	A Moomba Trading Hub (MTH) should be established.
Major Energy Users, p. 4	Physical constraints exist at Wallumbilla. Moomba GSH has potential to ease shortages of gas and increase competition.
Manufacturing Australia, p. 6	AEMO should develop additional gas trading hubs, such as proposed at Moomba. All gas should be delivered, priced and traded at designated hubs and published against a benchmark price. As further pipelines and supplies are developed, other hubs can be added to the marketplace.
Manufacturing Australia, p. 8	The AER should extend the National Gas Access Arrangements to gas production facilities where they have monopoly positions so that all gas producers can have access on an equal footing. Governments should restrict the capacity of any one entity, joint venture, or partnership to control a large or dominating share of reserves, while promoting entry of new competitors from the point of resource control and extraction. The Federal Government should actively facilitate the entry of new competitors to break down existing concentration.
Origin, p. 4	Focus for the GSG should be on improving participation and liquidity. A Moomba hub could facilitate this.
Origin, p. 4	A valuable future development may be to encourage participation by non-physical participants such as financial institutions. This in turn will require balancing services to allow them to close out their positions, which is linked to a single trading product at Wallumbilla. Origin supports the current process to develop and assess the merits of a single product at Wallumbilla.

Stakeholder	Comment
Origin, p. 4	In light of the success of the Wallumbilla GSH, Origin suggests there is a strong impetus to cease operations of the Brisbane STTM.
Qenos, p. 5	Supports the development of the proposed GSH at Moomba.
QGC, p. 1	Wallumbilla Gas Supply Hub provides added flexibility in managing short-term gas positions, and, importantly published information on bids and offers, traded prices and volumes.
QGC, p. 5	Introducing additional trading hubs offers a short-term solution, but could split market liquidity (eg, at the Wallumbilla GSH) and create greater price volatility. Given the size of the east-coat market, there is significant benefit in concentrating trading/liquidity at one trading point (eg, Wallumbilla). An effective short-term capacity trading mechanism (reflecting efficient short-term pricing), would likely enable Southern participants (and those looking to supply the Southern markets) to more cost effectively transact and manage risk using Wallumbilla as a central point. QGC has suggested rather than establish a new pricing point at Moomba, it becomes a new GSH delivery/receipt point and trades are referenced to Wallumbilla.
QGC, p. 5	The creation of a “within-day” gas market should be a priority issue, with an extended trading day.
Santos, p. 4	Limited available capacity to transport gas limits arbitrage opportunities between markets.
Santos, p. 5	Supportive of Moomba GSH.
Santos, p. 5	The impact of trading at WGSH should not be a consideration in determining if another hub or delivery point is needed: if there is demand for an additional hub or delivery point and this is executed properly, this will bring in new market participants and give confidence to the whole market, increasing liquidity.
Santos, p. 5	The ability to facilitate “bespoke” trades through the WGSH is a good functionality.
Stanwell Corporation, pp. 3-4	Liquidity in facilitated markets limited by access to underlying infrastructure. Complexity and cost of facilitated markets are a barrier to entry.
Stanwell Corporation, p. 4-5	Brisbane STTM reduces liquidity at Wallumbilla Gas Supply Hub, as month ahead balancing in the Brisbane STTM prevents trading on a day to day basis at Wallumbilla GSH due to uncertainty over how much to set aside for

Stakeholder	Comment
	balancing obligations. Ideally, one market would operate in each region in order to maximise liquidity.
Stanwell Corporation, p. 6.	A Moomba GSH would: • increase liquidity in the market overall; • reduce liquidity at Wallumbilla GSH; and • add complexity to trading between the hubs due to the different start of gas day.
Markets: risk management	
Adelaide Brighton, p. 3	Users being able to manage market deviations through market schedule variations (MSVs) allows risks to be reduced.
AGL, p. 3	Experience of the Wallumbilla gas supply hub vindicates the role played by AEMO in removing settlement or counterparty risk often associated with bilateral trades.
Alinta, p. 8	Exposure to additional pipeline charges is unknown at the time of capacity trade and can be difficult to manage.
Alliance of industry associations, p. 7	Within the alliance of industry associations, individual associations support: • the development of financial derivatives a means for risk management (alternative to physical supply contract). This will need a daily gas price to settle against, which is the role the STTM and the DWGM currently plays; and • consideration of compensation for any businesses that are required to be curtailed if they have a firm gas supply contract and gas transportation agreement in place.
ESAA, p. 1	Supportive of an incremental approach to gas market reform that has regard for existing contracts.
ESAA, p. 5	In the STTM there are a number of complex charges/payments associated with market deviations that cannot be effectively hedged. These include charges/payments relating to: market operator services (MOS); short and long term deviation payments; contingency gas (which has not been required to date); and the settlement surplus or shortfall that is allocated at the end of each month.

Stakeholder	Comment
ESAA, p. 7	Similar to the STTM, risk in the DWGM is not embedded in a single daily market price. Reducing the complexity of ancillary payments and uplift charges and linking them to the market price could improve participants' ability to assess and manage risk.
EnergyAustralia, pp. 2-3	There is no transparent forward market, limiting participants from effectively managing risk. This is increasingly important given that the domestic gas market will be linked to the international market, requiring the hedging of currency and oil prices risk.
EnergyAustralia, p. 2	Market reform must facilitate price discovery and transparency in spot markets.
ERM Power, pp. 3-5	The recovery of part of the cost of ancillary payments through the allocation of congestion uplift is not on a cost to cause basis and is inequitable. A rule change should be made to enable all uplift costs to be recovered through the existing surprise and common uplift mechanisms.
ERM Power, pp. 6-7	There is value in exploring the merits of moving away from the current unconstrained pricing and ancillary payment/uplift cost regime. Congestion uplift fails to allocate costs to their cause. The remaining cost allocation mechanism smear costs across the market. Uplift risk is unhedgeable. LNG can mitigate risk, but this is expensive. A financial market to mitigate risks is precluded by the current arrangements.
ERM Power, pp. 7-8	The maximum market price in the DWGM should be reviewed, with specific consideration to reduce it to a lower level. The higher the market cap the higher the risk faced by retailers.
GDFSAE Australia, p. 2	Market liquidity and the opportunity to manage risks arising through market participation do not match participants' interests. The reasons for this include absence of integration, historical hub by hub developments, markets overly influenced by physical limitations, high entry and transaction costs, and focus on bilateral contracts and contractual strictures.
Lumo Energy, p. 7	A review of the MOS arrangements would be welcomed, as MOS is an inappropriate way to manage deviations. Intraday trading would potentially change the need for MOS, by enabling participants to be better informed of their actual deviations on a gas day.

Stakeholder	Comment
Lumo Energy, pp. 15-16	A review of the methodology, settings, and the need for increased harmonisation between the STTM and DWGM market parameters is necessary. A recent review undertaken by AEMO suggested that the LNG industry would increase risk for market participants.
Lumo Energy, pp. 16-17	A review investing the feasibility of making AMDQ and AMDQcc firmer would be appropriate.
Origin, pp. 2-3	Facilitated markets are complex, impacting risk management. The current pricing structure is not truly reflective of market costs in either the STTMs or DWGM. To improve this, market costs should be incorporated into the market price.
Qenos, p. 4	The STTM has been a positive development, providing an alternate means of purchasing gas, and price transparency. However, pricing can be volatile, and long term gas contracts are still required. With five gas producers providing 85per cent of the gas, there may be significant power over long term gas pricing.
Qenos, p. 5	Financial derivatives would be useful to manage risk.
Santos, p. 4	The ability to set a price ceiling in the STTM markets minimises price risk.
Santos, p. 4	Santos would welcome a review of the STTMs for inclusion of an intraday trading service. Under the WGSH, consideration should be given to making intraday trading more cost effective.
Santos, p. 4	STTMs are an effective mechanism for the efficient management of the daily supply and demand imbalances.
Pipelines: capacity trading	
Adelaide Brighton, pp. 4-5	The condition where shipper can purchase all firm capacity on a pipeline and then restrict customer to purchasing from that shipper is not optimal. The shipper gains monopolistic power which it can abuse by forcing customers to purchase both commodity and haulage from one supplier. The alternatives are building a network bypass to gain access to competitive market pricing, or relocation of facility. Such shippers should be required to make available capacity that is not utilised.
AGL, pp. 5-6	"Trade inhibitors" associated with current pipeline contracts and practices are:

Stakeholder	Comment
	• The enumeration of delivery points in GTAs and the delays in including an additional delivery point get in the way of shippers being able to offer their capacity to a third party. Delivery points should be grouped into zones to provide shippers flexibility. • The often related requirement to negotiate an allocation agreement with the incumbent shipper at that delivery point. If the pipeliner were to provide the allocation at that delivery point as part of a standard service offering for delivery points, this obstacle can be sidestepped. • Nomination cut-off times in existing GTAs are generally not based on operational requirements. • Services related to forward haulage service are more in the nature of a transaction that would warrant an administrative charge, rather than a volume-driven fee structure. Furthermore, standardising the terms and conditions would keep transaction costs down. AGL is broadly supportive of reform to enhance capacity trading, but consideration should be given to: • impacts on investment; • the need to accommodate shippers' and retailers' need to offer firm gas to end-users; and • the suitability of overseas models in the Australian context.
Alinta, p. 7	Alinta is of the view that capacity trading in the east coast gas markets is currently less than ideal, driven by information on available capacity in the forward period being limited to select listing services.
Alinta, p. 8	Marginal benefits of increased pipeline trade may be dwarfed by more significant benefits in retail gas markets.
APA, pp. 20-22	APA supports industry led initiatives to develop secondary trading in pipeline capacity. For example, APA and other pipeline owners have recently introduced new services to support additional capacity trading. APA considers its Capacity Trading Service “addresses an existing barrier to capacity trading, being the administrative complexity and risk of managing shipper nominations, allocations and imbalances on behalf of the counter-party.” Additional measures, such as further improvements to the Bulletin Board and the Energy Council's capacity trading rule change are expected to reduce barriers to capacity trading by improving transparency and lowering search and other transaction costs.
Arrow Energy, p. 6	The full benefits of market developments and enhanced trading arrangements cannot progress without a more

Stakeholder	Comment
	effective transportation regime, including capacity trading and access, which encourage efficient market outcomes. The benefits of a single pipeline regulatory regime with clear mechanisms for accessing capacity will enhance investment certainty and facilitate deeper market development. Attaining access to capacity presents a number of challenges that must be addressed: the rights of existing asset owners; the impacts on the risk position and opportunities for asset and capacity owners; the mechanism for providing access; commercial terms; and the benefit to the market.
AEMO, p. 1	Recommends three areas of development to lead to more efficient secondary trading of pipeline capacity: • incentives for shippers and pipeline owners to make available unused pipeline capacity, particularly on a short-term basis; • mechanisms to support trading of capacity on a short-term basis; and • services from pipeline operators to improve intermediation such as standardised terms, harmonising tariffs, maximising tradable legs of pipeline capacity.
Australian Pacific LNG, p. 2	It is important that current transportation arrangements are honoured. However, APLNG supports the ability to access pipeline capacity not being utilised by the primary holder. Streamlined standard commercial terms based on marginal cost basis would assist in this effort.
APPEA, p. 3	Supports the introduction of a pipeline trading capacity initiative.
APGA	Trading of transmission capacity and commodity gas occurs in the eastern Australian gas market. Additionally, short term capacity is made available to all market participants on a non-discriminatory basis (as available and/or interruptible capacity). APGA does not support the view that eastern Australian pipelines are under-utilised, noting that the annual utilisation rate is 52 per cent, compared to the Midwest (32 per cent) and Northeast (30 per cent) regions of the United States. APGA considers there were two impediments to increased short term capacity trading, both of which have been resolved. The first relates to lack of harmonised contracts and information availability for transfers, which has been resolved through industry and AEMO led processes (bulletin board and standard contracts). The second is the limited number of participants in the markets, where participants with capacity cannot find a willing counter-party at the delivery point. APGA considers this is largely addressed by pipeline owners providing delivery point flexibility to

Stakeholder	Comment
	shippers. Any further impediments to trading should be resolved through the COAG Energy Council's rule change proposal to support capacity trading. APGA considers this process, enhanced by the industry-led initiatives, should be given time to work before further changes are contemplated. APGA does not support the introduction of an oversell and buy back mechanism into the eastern Australian gas market.
GDFSAE, p. 6	Easier trade of capacity should be an outcome of the Review.
GDFSAE, p. 6	GDFSAE does not see the capacity discussion as a debate between contract and market carriage models. While there are identifiable impediments to capacity trading on contract carriage pipelines, market carriage also creates complexities and it may fail to provide signals for pipeline augmentation.
GDFSAE, p. 6	Given the need to underpin investment it is understandable that pipeline owners and operators are defensive of the contract carriage model. While supporting pipeline investment cannot be overstated it should not mean the existing framework is sacrosanct. While long term contracts are not absolute barriers to capacity trading in all forms they currently inhibit capacity trading.
GDFSAE, pp. 6-8	Any developed approach to capacity trading should take account of existing arrangements and should be used uniformly across Eastern Australia. While voluntary mechanisms have been advanced, experience suggests that governments can play a role in facilitating structures and frameworks that encourage liberalised market outcomes. As an alternative to current arrangements, and models overseas, GDFSAE can conceive of a model which allows incumbent shippers to signal the price at which they would be willing to surrender tranches of capacity, including at times of high usage. Areas for investigation are: • mandated standard contractual terms for short and medium term capacity trades; • addressing prohibitive contract terms; • contractual congestion; • availability of bundled products between hubs;

Stakeholder	Comment
	• trading models used elsewhere; • alternative pipeline investment models; and • pipeline obligations to limit market impact.
ESAA, p. 1	A key area includes pursuing enhanced market transparency and contract standardisation in support of industry-led pipeline capacity trading initiatives.
ESAA, p. 9	Flexible and transparent access to pipeline capacity is important for the development of a liquid and transparent commodity market. However, the property rights of existing capacity holders should be considered. It is not clear that implementing some form of mandatory trading would deliver the efficiency gains necessary to justify such significant intervention. The 'trade facilitator' model recently developed for the South West Queensland Pipeline, RBP and Queensland Gas Pipeline is an important initiative in this regard. It demonstrates the ability of industry to respond to changing market needs in a targeted and light-handed manner. The COAG Energy Council's agreement to pursue enhancements to information provision and standardisation of contractual terms and conditions for secondary capacity trading is a positive step. It will be important to allow them sufficient time to take effect before additional interventions are considered.
EnergyAustralia, p. 2	Gas transportation is dominated by opaque and bespoke contract carriage arrangements. The market carriage model in Victoria is the exception, but it is complex and interfaces poorly with other pipelines.
EnergyAustralia, p. 3	For the contract carriage model, holders of existing capacity have strong commercial incentives to trade capacity, and reform should focus on removing barriers to mutually beneficial trade: • standardisation of contracts; • simplified processes to change delivery points; and • reduced search and transaction costs for short term trades.
Epic Energy, pp. 1-3	Contract carriage supports capacity trading, as the contracted terms allow participants to negotiate a price that reflects a reasonable allocation of risk between the contracting parties. Further, secondary trading of pipeline capacity already occurs and the benefits of further reform are likely to be limited. However, if a formal secondary trading

Stakeholder	Comment
	arrangement is put in place, it must preserve the value of the primary capacity market. Epic also noted that there is data to suggest that Australian capacity utilisation rates are higher than utilisation rates in North America and Europe.
ERM Power, p. 11	Supports recent developments to facilitate capacity trading. Considers it may be worthwhile revisiting the concept of a voluntary capacity trading platform. This may include considering how spare capacity may be released for use.
GLECMU, pp. 2-3	Improving the efficient access and use of pipeline and gas infrastructure is a fundamental component of the gas market. The full benefits of market developments and enhanced trading arrangements require a more effective transportation regime, including capacity trading and access, which encourage efficient market outcomes. Consideration should be given to all market-based options that facilitate greater access to capacity. The preferred mechanism for realising shared use should provide clear signals to commercially incentivise owners to facilitate access.
Jemena, pp. 1-2	Following extensive consultation, the industry is implementing measures to encourage more efficient usage decisions on secondary pipeline capacity trading.
Lumo Energy, p. 18	Lumo is supportive of the current process for improving information provision to facilitate capacity trading.
Major Energy Users, p. 4	Information asymmetry is a major barrier to efficient trading, and requires more than enhancements to Bulletin Board to be rectified.
Major Energy Users, pp. 7-8	Hoarding pipeline capacity is a problem in STTMs and pipelines outside the STTMs. Interruptible capacity is offered at a higher cost than firm capacity or not offered at all. It is not clear that better mechanisms to trade capacity will result in more capacity being released.
Origin, p. 4	The AEMC should, in the first instance, investigate and articulate the current issues with capacity trading, and their materiality. Such a review should also consider the range of services available.
Origin, pp. 4-6	Market arrangements are sufficiently flexible and incentives exist for shippers to provide capacity to the market if demand exists. A guiding principle for any proposed change should be that there is no diminishing of property rights for existing capacity holders.

Stakeholder	Comment
	Origin considers there may be merit in a multi-pipeline voluntary trading platform but cautions against any more interventionist market design changes in the first instance. Origin considers this approach is the most cost-effective way to encourage capacity trading that preserves existing capacity rights and will not adversely impact future investment. A working group of all relevant stakeholders be established to fully develop and cost this proposal.
Origin, pp. 7-8	Were regulatory intervention required (which Origin considers would only be in the case that other, non-regulatory intermediate steps were implemented and proven to be unsuccessful), Origin consider that caution be applied to the appropriateness of overseas experience to the Australian context, and consideration be given to: • a shipper's flexibility to respond to changing supply and demand patterns; • impact on investment; • the entry-exit system; and • transmission system operator estimation of capacity and use.
QGC, pp. 2-3	Short-term capacity trading arrangements are essential to develop market liquidity, reduce price divergence and facilitate the development of the futures and forward markets. Addressing this issue is central to “opening-up” the market and enabling gas to be directed towards participants who value it most at any given time. Current impediments to short-term trading in capacity include: • potential lack of market awareness by shippers holding capacity; • transaction costs potentially exceed value of sale; • holding capacity maintains flexibility and avoids nomination complexities; • potential commercial opportunities: managing capacity may create price differences; and • contractual clauses which preclude trade.
QGC, pp. 3-4	An oversell and buy-back mechanism (akin to that used in the European market) could be introduced. To do so, the AEMC should consider the operational and risk management measures for pipelines and the structure of existing contracts. Encourages the AEMC to consider this matter further.

Stakeholder	Comment
Santos, pp. 1&7	The main impediment in the current facilitated markets is the lack of a firm transport availability to get gas to and from different trading markets. The current options to trade capacity are good for large players, although they may not meet the future vision of an actively traded market between locations and arbitrage trading opportunities. A standardised market for available capacity should be introduced, with reduced transaction costs. Also, current pipeline owner administrative costs are too high for new traders.
Stanwell Corporation, p. 3	An active capacity trading market is unlikely to occur without changes to existing access arrangements and regulatory arrangements for nodal points. Capacity holders can reserve capacity with little or no incentive to release it, reducing available capacity for smaller and new entrant users.
Stanwell Corporation, p. 3	Pipeline arrangements can restrict competition. For example, excessive fees are charged on intraday nominations, preventing users from purchasing unused capacity from other parties. Instead, users are encouraged to purchase services from the pipeliner.
Stanwell Corporation, p. 7	Other impediments to capacity trading include: • non-standard contracts; • onerous set up process; • point to point GTAs; • inadequate information on available capacity; and • significant variance charges on capacity trades.
Stanwell Corporation, p. 6	Trading mechanisms and regulatory changes to incentivise pipelines to support such a market should facilitate capacity trading.
Pipelines: investment	
APA, pp. 14-16	APA considers that the current arrangements provide a supportive and appropriate regulatory environment that provides for efficient investment in most pipelines (except the DTS).

Stakeholder	Comment
	The regulatory arrangements in the DTS are undermining efficient and timely investment in the DWGM, particularly now that AMDQCC has been determined to be a reference service with an associated regulated tariff applied. APA considers the result of this decision is that it no longer has certainty of throughput or revenue from allocation of AMDQCC, therefore undermining the original intent of AMDQCC. APA is also concerned about the opportunity for free-rider participants to benefit from investment in infrastructure in the DTS as a result of the 'socialisation' of investment under the market carriage model in Victoria.
Australian Energy Regulator, pp. 3-4	There is evidence that the provisions in the NGR (and its predecessor, the Gas Code) enable timely investment in the DTS regardless of its timing within a regulatory period.
APPEA, p. 2	The APPEA recognises the importance that bilateral contracts have played in underpinning market development on the east coast.
APGA	Since 2000, APGA's members have invested in and built over $2.2 billion of new infrastructure providing 4000km of coverage across 10 new gas transmission pipelines. Since 2010, APGA members have invested over $850 million to expand existing infrastructure. These investments have been facilitated through bilateral negotiations and contracts. Further investment will be required to meet the needs of participants in the future. There has been a move towards short-tenure contracts to underpin infrastructure investment recently. For example, APA has announced a capacity expansion for transportation services between Victorian and NSW at a cost of $160 million for three shippers for contracts of between four and six years, compared to historical contract lengths of over 10 years. As a result, the pipeline owner is bearing more risk associated with recontracting for this investment. In relation to the DTS, APGA are concerned that the regulatory arrangements in place prevent investment is from occurring in a timely manner. Delays in investment caused by regulation have implications for efficiency and market welfare. In contrast, pipelines that are fully covered and tariff-regulated under contract carriage have less difficulty investing outside the regulatory cycle as they can offer firm capacity rights. There are significant costs associated with market carriage and access regulation as a result of delays in investment.
BHP Billiton, p. 3	The role of gas storage facilities in supporting fully functioning gas markets is important, particularly in the context of highly seasonal demand. The eastern Australian gas market is at the early stage of gas storage development.
ESAA, p. 7	Investment decisions in the DTS are driven by the regulatory process, which may be less efficient and timely than relying on market driven investment decisions.

Stakeholder	Comment
ESAA, p. 8	Significant investment in pipeline capacity has occurred, with the current framework providing a reasonable balance of end-user protection with service provider protection and incentives.
ESAA, p. 8	Tariff uncertainty due to prospective near-term regulatory reviews creates significant risk for both pipeline operators and financiers. As such, the light handed or no coverage options are seen to be important features of the regulatory environment. While the no-coverage option may create some potential negatives from the perspective of third parties, it is not clear that it creates a fundamental constraint to the development of the industry.
EnergyAustralia, p. 4	For the market carriage model, the review should focus on ensuring efficient and timely investment in new capacity and improving participants' ability to manage risk.
Epic Energy, p. 2	Timely and efficient investment occurs in response to market demand on contract carriage pipelines.
ERM Power, p. 6	Lack of firm capacity rights in the DWGM reduces incentives for market-led investment in pipeline capacity expansions. This can lead to a lack of transmission capacity, with expansions not occurring in a timely manner, or at all. Optimisation of investments and daily operations is not enabled. Options to introduce market-led investment and make investments more efficient should be investigated. This should not build on the current uplift/AMDQ mechanism, which does not provide effective price signalling. New investments may be able to be contracted for, providing firm capacity rights for participants.
Jemena, pp. 2-3, 7	The market currently provides incentives for the efficient use of and investment in pipeline services and Jemena has invested $450 million in new capacity since 2007. Any policy or regulatory response to encourage efficient utilisation of and investment in pipeline infrastructure must be: • proportionate and recognise pipelines account for around 5 per cent of a typical residential customer’s gas bill in NSW; • developed with a clear understanding of the problem with current arrangements, as well as the costs and benefits of any proposed response; and • guided by the long term interest of customers.
Lumo Energy, pp. 12-13	Investment in the DTS is occurring in an efficient and timely manner. There is a lack of evidence that investment has not been timely or efficient.

Stakeholder	Comment
Major Energy Users, p. 3	Investment required in transmission capacity at critical points in the system to better facilitate bi-directional gas flows, storage, swaps, and liquidity.
Major Energy Users, pp. 9-10	If insufficient capacity exists on a contract carriage pipeline, participants seeking access must fund new investments, which may provide a financial barrier to their entry. Market carriage pipelines allow new investment to occur with costs for increased capacity socialised so all shippers pay the same rates for the same service. The claim that the DWGM does not provide sufficient investment signals needs to be rigorously assessed. AEMO provides an independent mechanism for assessing investment in the transmission planning role. While there may be opportunities to improve this, it is not clear that this arrangement warrants a major restructure.
Manufacturing Australia, p. 7	The Federal Government should designate gas pipelines as assets of national importance as a key step to ensure equality of access.
Manufacturing Australia, p. 7	The COAG should map and develop a network of pipelines to bring Australia’s stranded gas assets to market and connect the Northern Territory and Eastern gas markets.
Manufacturing Australia, p. 7	Federal and State governments should identify strategic “energy corridors”: regions or zones that are crucial to future energy needs, either for resource extraction, pipelines of other infrastructure.
Santos, p. 6	5 year determination cycle can delay investment in the DTS.
Santos, p. 7	The low number of uncovered pipelines is not a concern in its own right. Investment, where there is demand, has been forthcoming, showing the market is working efficiently.
Stanwell Corporation, p. 2	Transmission pipeline investment and revenue should be regulated by the AER under a NEM-style carriage model operated by AEMO.
Stanwell Corporation, p. 3	Current regulatory arrangements seem to reward pipelines for constraints rather than encouraging investment.

Stakeholder	Comment
Pipelines: trading between jurisdictions	
Adelaide Brighton, p. 4	It is difficult to move gas from Victoria to adjoining regions. Consistent regulatory framework may assist in ability to move gas from one region to another.
AGL, p. 5	Given the increasing interconnectedness of pipelines, it would be appropriate to further review the interface between Victoria's market carriage regime with contract carriage regimes in SA and NSW.
AGL, p. 7	The interaction between the market carriage and contract carriage models is an appropriate consideration for this review. However, AGL does not endorse a review of the merits of market carriage versus contract carriage options.
Alinta, p. 6	Getting gas into the hub precedes any opportunity for the hub to work as a viable market overall and for individual trades to occur. Unless all participants at the hub can guarantee delivery, trade will be always to a degree remain constrained.
APA, p. 15	APA considers the application of system security requirements under the NGR is inconsistent with the NGO, in that there is a bias towards Victorian system security at the expense of gas flows to other jurisdictions, particularly New South Wales.
APA, pp. 25-27	APA considers that the current access regime provides a supportive and appropriate regulatory environment that provides for efficient investment in most pipelines (except the DTS). Nevertheless, APA has raised concerns about the following aspects of the regime: • redundant assets provision; • speculative capital expenditure account; and • gaps in the operation of the tariff variation mechanism.
BHP Billiton, p. 2	There is an opportunity for Australian energy regulators to consider a more uniform approach to gas pipeline regulation in a manner similar to that which applies in other markets such as the UK and the United States.

Stakeholder	Comment
EnergyAustralia, p. 2	Reform should focus on encouraging trade between locations.
EnergyAustralia, p. 4	The review should focus on the interaction between the Victorian system and contract carriage pipelines.
Jemena, p. 6	Jemena does not consider that differences in market and contract carriage arrangements across eastern Australia represent a material issue. Any proposal to overhaul existing arrangements must have regard to existing property rights, as well as the costs, benefits and risks of alternative arrangements for participants, as well as end consumers. Jemena considers there is scope for harmonising market parameters, such as the alignment of gas days.
Major Energy Users, p. 5	AMDQ is allocated to retailers rather than consumers, limiting the ability of consumers to switch retailer.
Major Energy Users, p. 6	Export arrangements between market hubs should be a focus of the review. Investment in transport within the DWGM to provide increased export can be addressed with the beneficiaries of increased capacity paying for in-region capacity that is required to enable additional gas for export from Victoria.
Origin, p. 3	Exports from the DTS should be considered equal to DTS demand as this supports the principle that gas should flow to the highest value use.
Santos, p. 6	Constraints are a daily occurrence out of the DTS.
Stanwell Corporation, p. 4	Supports the integration of the east coast gas market, and suggests a NEM-style market operated by AEMO.
Pipelines: third party access arrangements	
APGA	At the time of establishment, the Victorian gas market was essentially an isolated market with significant excess capacity. There has been significant change in the market since then, with the construction of the Tasmanian Gas Pipeline, SEA Gas Pipeline and Eastern Gas Pipeline, as well as the construction and expansion of the Victorian Northern Interconnect. Historic issues that inhibited the transportation of gas from the DWGM to contract carriage pipelines have largely been resolved through an AEMO procedure change (matching allocated AMDQCC to firm capacity rights at withdrawal points).

Stakeholder	Comment
APGA	Transmission pipelines have an important role in developing liquid, transparent and competitive wholesale markets, however further regulation is not the 'silver bullet' to further development of the markets. The current access regimes in the Gas Code and NGL have applied alongside significant investment that has promoted competition between gas supply basins. As interconnection between the pipelines increases, pipelines must remain competitive as alternative sources of supply and transportation become available to shippers. In relation to the DTS, APGA are concerned that the regulatory arrangements in place prevent investment from occurring in a timely manner. Delays in investment caused by regulation have implications for efficiency and market welfare. In contrast, pipelines that are fully covered and tariff-regulated under contract carriage have less difficulty investing outside the regulatory cycle as they can offer firm capacity rights.
EnergyAustralia, p. 2	Reform should focus on encouraging trade in pipeline capacity.
Epic Energy, pp. 2-4	Contract carriage arrangements enable pipeline owners and shippers to negotiate bespoke contracts that best reflect the variability in supply and demand in major demand centres. Contract carriage also supports and encourages timely investment in pipelines.
Jemena, pp. 3-4	Contract carriage arrangements have allowed Jemena to provide innovative services to meet the needs of their customers, including: allowing shippers to change their delivery and receipt points, and storage products to allow intra-day nominations. Jemena maintains non-discriminatory access policies for both the EGP and QCP, which mean that available capacity is advertised on the Jemena website and all shippers have equal access to it.
Major Energy Users, p. 3	Impediments to access to pipelines and capacity trading exist and, therefore, the framework is not delivering efficient outcomes.
Major Energy Users, p. 7	A number of pipelines are monopolies but are uncovered. Several regional industries and cities are provided gas from a single, unregulated pipeline. The regime to allow for these pipelines to be covered is inadequate for these purposes; the criteria to gain coverage create a major hurdle to any party seeking coverage.
Manufacturing Australia, p. 6	The objective of market reforms should include access to infrastructure to enable producers to bring their product to market.

Stakeholder	Comment
Stanwell Corporation, pp. 3, 7	Access arrangements are inadequate as capacity holders are not incentivised to release spare capacity. As available is inadequate for many participants.
Information accessibility	
Alinta, pp. 3-4	As a general measure, the level of transparency [in relation to the LNG] market should be at least equivalent to the National Electricity Market (NEM) and in the spirit of disclosure obligations for the Australian Stock Exchange. In Alinta's view there are significant benefits to all parties at some level through increased information disclosure and the removal of information asymmetries. Given the clear connection between gas production, gas prices and electricity generation, there is a compelling argument that a similar compulsory reporting obligation to the NEM should be required for upstream gas producers with respect to any medium term changes in the capacity of their production facilities. The existing Gas Bulletin Board requirements in Western Australia could be used as a model for the east coast.
Alinta, p. 4	The current short-term capacity outlook information has been effective in informing participant decision-making. There is, however, further scope for enhancement. Consideration should be given to: • line-pack data, provided by relevant zones, at the beginning and end of day; and • intra-day data on capacity, flow and line-pack.
Alinta, p. 7	Alinta would encourage the review to consider steps to increase information from holders of available capacity.
Alliance of industry associations, pp. 6-7, 13	Gas market solutions must reflect the full range of identified market-based reforms for the gas market, including disclosure of available capacity at all stages of the gas value-chain. There should be improved planning and transparency mechanisms such as the Gas Statement of Opportunities and Bulletin Board, and continuing reforms to publish available transmission pipeline capacity and accelerating efforts to develop a published gas price index.
Alliance of industry associations, p. 7	Within the alliance, individual associations support: • the introduction of an Independent Gas Commissioner in each state to oversee gas field development much like has been established in Queensland. This would provide a trusted, independent source of information on gas

Stakeholder	Comment
	fields and their environmental performance; • the provision of fact-based information and education to assist all stakeholders understand the sources and use of gas throughout the economy. This could include the ongoing sourcing of gas from hydraulic fracturing methods over significant amounts of time in East Coast markets; and • increased transparency for the dealings between gas pipelines and gas shippers, so that gas users are best placed to understand ahead of time how the market is functioning.
Argus Media, pp. 3-4	Price transparency can best be promoted by encouraging independent media organisations such as energy Price Reporting Agencies to produce price assessments that most accurately reflect the supply and demand fundamentals of a freely operating, non-price regulated market. The AWX – the Argus Wallumbilla Index – provides a weekly price reference for gas traded at Wallumbilla for delivery on a month ahead basis, and this is an example of such a product. Price reporting agencies should be recognised for their role in bringing transparency to otherwise opaque markets, and they should be left to function without government interference, oversight or regulation. Government can play a role in enhancing price transparency by encouraging market participants to report comprehensive transactional and market information to price reporting agencies, avoiding the adoption of legislation that might deter the flow of information or price reporting agencies, and adopting independent price assessment for tax reference purposes.
Arrow Energy, p .5	In the absence of prohibitive costs and breaches of confidentiality, Arrow supports improvements in information availability, transparency and discovery for the purpose of facilitating trade and liquidity, and providing clear price signals. Aspects of data provision that should be considered in identifying the most appropriate data set include: accuracy of data (noting physical constraints), frequency of data, aggregation of data, timing of data release (daily, hourly or real time), the cost and timeframe required to establish measurement infrastructure to provide data.
Arrow, Energy, p. 9	Arrow believes that information currently being provided by the Wallumbilla hub, combined with work being undertaken by AEMO and the industry, will meet participant's needs.
AEMO, p. 2	There may be value in improving the Bulletin Board to provide more relevant and dynamic information (eg real time data and information about storage).
Australian Energy Regulator, p. 3	As the market matures, the AER would propose reporting more measures on the Bulletin Board and at the GSH.

Stakeholder	Comment
Australian Pacific LNG, p. 1	Supports the increased sharing of information and continued development of the Gas Bulletin Board with regards to: real time information of volumes; pipeline utilisation rates; posting of available capacity; and establishing a central data resource.
APGA	There are opportunities to enhance existing information available on the Bulletin Board. In particular, APGA considers the publication of two existing AEMO data sets would provide additional transparency and assist capacity trading: • a graphical representation of historical daily flow data against pipeline capacity (implemented in Bulletin Board redesign in December 2014); and • analysis of historical flow data on each day of the year. Further, APGA considers the Bulletin Board should publish available firm capacity by pipeline each month, with a 12 month forecast to give the market a 'clear indication of current and future available capacity.' Additional information on the export and production capability, particularly in relation to the LNG facilities at Gladstone is critical to market participants' decision making.
GDFSAE, pp. 4-5	Presently, information arrangements are fragmented across multiple platforms and are incomplete. In general terms, efficiency will be maximised by appropriate information disclosure to enable transparent price discovery, true incentives to be revealed and risks to be borne by the most appropriate parties. This suggests a level of transparency at least equivalent to the National Electricity Market and in the spirit of disclosure obligations for the Australian Stock Exchange. GDFSAE believes the review should consider information on the use of line pack, flow and nominations, medium term system adequacy, contracted capacity, injections and withdrawals and upstream supply. Areas for investigation are: • information adequacy; • use of existing systems; • roles of contracts in accessing data; • producer data; • gas demand data;

Stakeholder	Comment
	• capacity and adequacy data; • load profile data by gas network area; • “real time” feeds; and • short term information.
GLECMU, p. 2	In the absence of prohibitive costs, the GLECMU support improvements in information availability, transparency and discovery for the purpose of facilitating trade and liquidity, and providing clear price signals.
ESAA, p. 10	The ESAA is supportive of efforts that increase the availability of gas market information. Areas for exploration include: • Enhanced firm/non-firm pipeline capacity and flow data. • Enhanced operational pipeline capacity information. However, it is premature to consider alternative arrangements relating to the provision of medium and short-term capacity information until these recent changes have been given sufficient time to take effect. • Information relating to relevant facilities and large users. • Beginning-of-day line-pack. The ESAA does not believe it is appropriate to enforce mandatory reporting of secondary capacity trades that occur off market.
EnergyAustralia, p. 2	Market reform must improve the accuracy, timeliness and transparency of market information about physical supply and demand. This is a potential priority for phase 1 of the Commission's review.
ERM Power, pp. 11-12	A deficiency is present in the lack of publicly available information relating to the LNG industry. The Bulletin Board should be amended to reflect the establishment of an LNG/Gladstone demand zone, thereby capturing LNG pipeline flows (historical and forecast) and capacity outlooks/outage information related to LNG facilities.
Jemena, p. 2, 3-4	Jemena recognises the importance of the price of transportation services being appropriately transparent to encourage efficient utilisation of the network. However, Jemena considers any policy or regulatory intervention must address a clearly defined market failure in relation to transparency in the pipeline sector and consider the current market, regulatory and contractual arrangements. Jemena supports the APGA low cost proposal for improvements to

Stakeholder	Comment
	the Bulletin Board to assist secondary trading without compromising confidentiality.
Lumo Energy, p. 8	STTM prices do provide a price that reflects the underlying supply and demand conditions in the market.
Lumo Energy, p. 11	Wallumbilla GSH provides very useful information to market participants.
Major Energy Users, pp. 4-5	Facilitated markets do not reflect market fundamentals, and forecasts for gas availability, capacity and price are either unavailable or inadequate. This impedes gas trade and risk management.
Manufacturing Australia, pp. 5, 6	The objective of market reforms should include daily publication of accurate and credible gas supply availability and price. AEMO should require: • gas producers to report and regularly update the market on proven and probable gas reserves; • pipeline transport pricing to be published based off a published benchmark price for the injection and withdrawal points; and • open access via electronic markets provided to all market participants. Participants requiring shipping can price and book transport off the electronic market.
Qenos, p. 2	Facilitated market prices should be included on the Bulletin Board. This is part of a broader recommendation to centralise information in one location to improve ease of contracting.
QGC, p. 6	As part of this Review, the AEMC should also identify any relevant changes to east coast gas market information reporting that are necessary to support the overall successful delivery of any of its key recommendations.
Santos, p. 4	Increased transparency of price and gas volume schedule would improve efficiency.
Santos, p. 5	The information provided for the GSH is satisfactory. Santos has been encouraged with the addition of moving to a single product.
Santos, p. 8	The information on capacity utilisation provided on the gas bulletin board is adequate for current purposes.

Stakeholder	Comment
Stanwell Corporation, pp. 7-8	Supports current work on redevelopment of Bulletin Board. Bulletin Board contains incomplete and untimely information. Information that would assist in participant decision making includes: • 12 month forecast of capacity, system adequacy and maintenance information; • intraday pipeline flows and linepack for all pipelines, not just regulated ones; • capacity and amount of available gas at storage facilities in Queensland, including non-designated facilities; • forecast and current amount of pipeline capacity available for storage; and • net system load profile for each demand hub.
Other	
Alinta, p. 9	Alinta encourages further consideration of a coordinated approach to system security that still retains control at the jurisdictional level but results in AEMO acting as the agent in charge of managing technical operations.
Alliance of industry associations, pp. 6, 8	The AEMC should acknowledge the full nature of energy use in Australia, the needs of energy users for an efficient, competitive market, and the full economic and environmental opportunities that are linked to the outcomes in the gas market.
Alliance of industry associations, pp. 7, 9-10	The AEMC should identify the critical evidence gap relating to the current and potential use of gas throughout the manufacturing sector and its supply chains.
Alliance of industry associations, p. 10	Consideration should be given to introducing a transitional mechanism that requires all stages of the gas value chain that have capacity available to provide an offer to the domestic market. This obligation should be underpinned by improved disclosure of capacity at all stages of the gas value chain.
Alliance of industry associations, p. 11	The alliance recommends a review is undertaken by the ACCC to assess the depth, liquidity and competitiveness of the Australian domestic gas market.
Arrow Energy, p. 3	Elements of market design that should be considered include: physical market security and stability, supply security, supply competition, provision of appropriate information, access to transportation capacity, supply and demand needs (risk and price), and price transparency.

Stakeholder	Comment
Arrow Energy, p. 4	The reforms required to deliver an integrated and efficient market are likely to be significant and wide ranging. An ad hoc or fragmented approach to the development of the market is likely to fail.
GDFSAE, p. 3	System security and security of supply are fundamental drivers of aspects of gas regulation and gas hub design, at times to the detriment of market development.
GDFSAE, pp. 3-4	While GDFSAE supports market led reform as a general principle, it is appreciated that facilitating timely development, especially in the face of significant challenges, is likely to require government and industry to take coordinated action. Areas for investigation are: • the role of industry and government; • consultation process and transition; • maintaining a focus on gas markets at a policy level on an ongoing basis to the same extent as occurs with electricity; and • rule change process consistency.
GLECMU, p. 2	Sufficient time for change needs to be considered in any decision making process, including appropriate consultation and transitional arrangements, particularly where major change is being proposed. Although the overall objective of policy should be to promote efficient markets, no participant should be materially disadvantaged by unexpected major changes.
Lumo Energy, p. 17	The rule that prevents anyone other than the Victorian Government and AEMO from submitting a DWGM rule change to the AEMC should be amended to be consistent with arrangements in the STTM. Rule change processes are too lengthy.
Manufacturing Australia	Recent changes have rendered the domestic market, dominated by historical structures and regulations, unworkable for demand side participants.
Santos, pp. 7-8	To achieve COAG's vision for gas, there needs to be a greater integration between the markets and pipelines.