Australian Energy Market Commission

REVIEW

STAGE 2 DRAFT REPORT

East Coast Wholesale Gas Market and Pipeline Frameworks Review

4 December 2015

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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 gas industry on the east coast of Australia is undergoing a transformation. A collection of largely isolated point-to-point pipelines have evolved into an interconnected network, supporting a series of increasingly interlinked markets.

This process has been accelerated by the commencement of liquefied natural gas (LNG) exports from Queensland. The development of an LNG export industry has driven an unprecedented increase in gas demand and supply, with consequential impacts on patterns of gas flows and wholesale gas prices. These factors have led to a renewed focus on market development and improvements in the fundamentals of gas trading arrangements.

To guide this development the COAG Energy Council established a set of principles referred to as the Energy Council's Vision ("the Vision") for Australia's future gas market.[1] A key outcome of the Vision is the establishment of an efficient and transparent reference price for gas. An efficient reference price requires a liquid market with many parties buying and selling gas, which necessarily implies that trade be focused at a point that best serves the needs of participants - another aspect of the Vision.

Growth in trading liquidity requires the creation of a self-reinforcing cycle that encourages both the demand and the supply side of the market to participate. More participants and greater traded volumes lead to more meaningful pricing signals, giving sellers confidence that they will have a market for their supply. Increased supply gives buyers the confidence to augment their bilateral contracts with traded gas from the market.

As trading volumes increase, financial risk management tools will be developed by industry, reducing the cost of managing price risk and encouraging even more participation in the physical market.

Achieving the Energy Council's Vision of a liquid wholesale gas market will lead to lower barriers to entry, promote competition and increase efficiency. Liquid trading markets promote the efficient allocation of gas and act as a credible alternative source of supply to bilateral contracts, contributing to competitive tension in bilateral contract negotiations. Liquid and transparent markets are also fundamental to consumers being able to know whether the price of gas reflects underlying demand and supply conditions.

However, and as recognised by the Vision, to develop liquid trading requires participants to be able to readily move gas between trading locations. This is especially important in an environment such as the east coast of Australia with few, geographically dispersed producers and users. If there are obstacles to participants being able to access transportation capacity, this will inhibit their ability to move gas to market and trade it, diminishing liquidity.

1 The Vision is set out in Chapter 1.

Against this background, the COAG Energy Council 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 is to 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.[2]

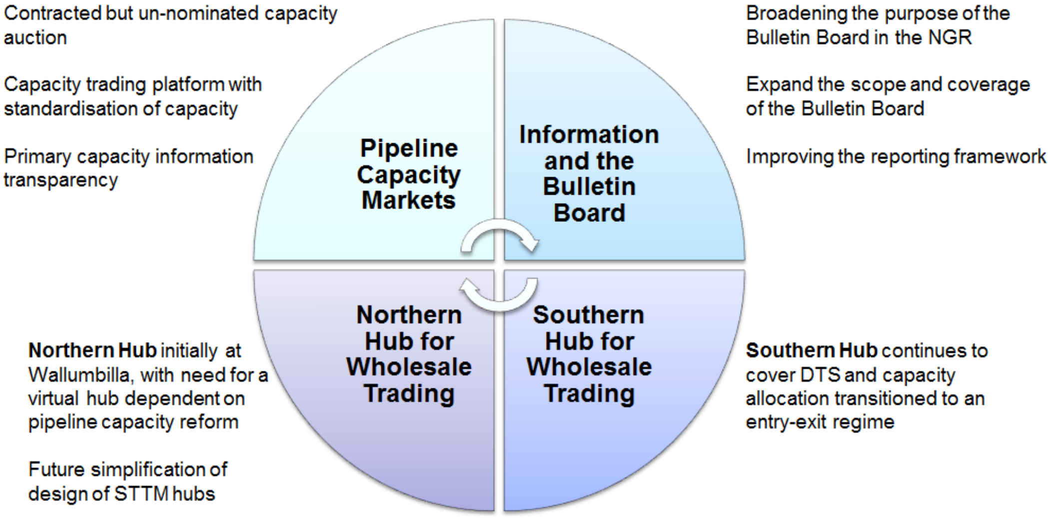
Concurrently, the Energy Council, at the request of the Victorian Government, has also asked the AEMC to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian Declared Wholesale Gas Market ("the DWGM Review"). The DWGM Review is being completed in parallel with the East Coast Review and the draft report has been published separately alongside this report.

The Commission's recommended roadmap for market development

The East Coast Review has been structured over two stages. In July 2015, the Commission published the Stage 1 Final Report for the East Coast Review, which included a gap analysis between the current market arrangements and Vision, as well as recommendations that could be progressed in the short term.[3]

In this report, the Commission has recommended an inter-linked package for gas market development that brings together recommendations on wholesale trading markets, pipeline access and information provision. As shown in Figure 1, the recommendations are interlinked and represent a balanced and proportionate suite of reforms designed to promote the Vision and the National Gas Objective.

Figure 1 An integrated reform package



2 See Appendix A.

3 Box 1.1 in Chapter 1 provides details of the current progress of the implementation of the Stage 1 recommendations. Stage 2 of the review has more fully developed the roadmap for future gas market development.

The Commission intends to submit its Stage 2 Final Report to the Council in May 2016. This will allow consideration of the findings from the Australian Competition and Consumer Commission's East Coast Gas Inquiry and any necessary refinements to the Commission's recommendations to be reflected in the Final Report.

Wholesale gas trading markets

The Commission is recommending a pathway for the future development of the market that seeks to concentrate trading at two points on the east coast – in the north by continuing to evolve the existing Wallumbilla Gas Supply Hub (GSH) and in the south by enhancing the Victorian DWGM.

Two primary pricing points have been recommended as the Commission is concerned that multiple trading locations unnecessarily split liquidity and reduce the benefits to participants of a liquid wholesale market. Prices at the two hubs would seek to reflect the differing market conditions in the two regions which have both significant sources of supply and demand:

- In Queensland, demand is primarily driven by LNG production and large users (including gas-fired generation) and there is significant conventional and unconventional gas production.
- In Victoria, gas is primarily consumed by residential customers, and so is driven by day-to-day weather and the seasons. There is also significant offshore production, which is increasingly important for domestic demand across the east coast.

Price discovery at both markets would be via exchange-based trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training where possible. This should lower transaction costs and complexity for traders operating across multiple markets, encouraging greater participation.

Reforming the existing DWGM arrangements to develop a Southern Hub

The Commission recommends that a virtual hub design continues to be applied in Victoria but with the following refinements:

- Transition to **voluntary exchange-based trading**, similar to the Wallumbilla GSH, to replace the current reverse auctions process, which would include:
  - incentives on participants to trade gas on the market to balance injections and withdrawals; and
  - certainty of delivery through residual balancing actions conducted by the hub operator.
- Transition to an **entry-exit regime** for allocating pipeline capacity, to replace the current market carriage framework.

The Southern Hub would consequently represent a “virtual” hub. Virtual hubs allow for title transfer of gas anywhere within the definition of the hub, obviating the need to purchase point-to-point pipeline capacity. There is instead a complementary system of entry and exit rights, which allow participants access to and from the hub, and which can provide investment signals lacking under the current market carriage arrangements.

As part of the DWGM Review, the Commission gave consideration to an option where the pipelines within the Victorian gas transmission system, but outside of the inner Melbourne ring, would be transitioned to a contract carriage framework. After consultation with stakeholders, the Commission considers that the characteristics of the Victorian system mean that effective capacity trading and hub services arrangements are unlikely to be practically achievable, and so a system of physical hubs and contract carriage would not be appropriate.

Evolutionary development of the Wallumbilla GSH to provide a Northern Hub

Wholesale commodity trading is already undertaken at Wallumbilla through the GSH arrangements, which were introduced in March 2014. Liquid trading is most likely to develop where there is a diversity of producers and users, and potentially other services that facilitate trading (such as storage). The Commission considers that Wallumbilla, which is located at the intersection of numerous pipelines connecting a range of producers, users and other facilities (including storage), represents the most appropriate location around which to base a northern trading hub.

Trading at Wallumbilla has been hampered to date by physical constraints within the infrastructure there, which means that gas cannot always flow completely freely, and which has required that trade be split across three points. AEMO has been undertaking a work program to progress this issue and is recommending that the Energy Council approves the introduction of "Optional Hub Services" arrangements. These aim to promote and facilitate the trading of hub services (primarily compression) to allow participants to access a single pricing point at Wallumbilla, in a similar manner to the Commission's recommendations regarding the trading of pipeline capacity.

Although such a Northern trading market would initially be a physical hub, the trading arrangements would be harmonised across the two markets as much as possible. This can be expected to increase efficiency through a reduction in complexity and regulatory burden. Furthermore, if the recommended initiatives to facilitate the trading of hub services and pipeline capacity (see next section) proved ineffective at promoting gas market liquidity, the Commission considers that there would be a case for expanding the hub either over the full Wallumbilla compound or more widely over pipelines in south-east and/or south-west Queensland.

Evolution of Moomba and the Short Term Trading Market (STTM) hubs

AEMO has announced that it will implement an additional GSH at Moomba by 1 June 2016. While not explicitly part of the Northern Hub, a second GSH at Moomba is likely to be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba could establish itself as a transit point for gas flowing between hubs, particularly given the recent announcement to connect the northern and eastern gas markets via a new pipeline (see section 5.3.2).[4]

Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends the STTM design then be simplified to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times.

The Commission is aware that many participants in the STTM hubs, particularly large users, highly value the certainty of supply provided. While such a mechanism would be provided in the Southern Hub, the Commission notes that there may also be a need to implement a mandatory balancing mechanism at the Northern Hub, if the liquidity of trading is insufficient to give participants certainty of delivery. This would be an important prerequisite to the simplification of the STTM design.

Improvements to the pipeline capacity frameworks

The Commission considers that the current contract carriage model of pipeline access can be improved so that market participants are able to obtain more flexible, lower cost and non-discriminatory access to pipeline capacity between hubs.

Non-discriminatory access to pipeline capacity and hub services is critical for the development of trading liquidity, as it allows all participants to compete at the hub on a level playing field. This means that all participants must be able to access services to transport gas to and from hub locations, as well as within hub locations, on the same basis. If this precondition is not met, trading liquidity and any consequential increase in competition will be inhibited.

In order to foster the development of a liquid market for the secondary trade of pipeline capacity, the Commission recommends the:

- introduction of an auction for contracted but un-nominated capacity - which is currently sold as "as-available" capacity - with a regulated reserve price on all pipelines; and
- mandatory creation of capacity trading platforms, to lower the transaction costs associated with trading capacity and through which information regarding all trades would be published. Capacity products would be standardised to facilitate trading through the platform.

The Commission considers that facilitating the release of as-available capacity through daily auctions will not undermine incentives for investment in pipelines due to the very short term nature of the capacity products being offered for sale.

4 Northern Territory Government Newsroom, *NT announces Jemena to build gas pipeline to east coast*, 17 November 2015. See http://newsroom.nt.gov.au/mediaRelease/16962.

Improvements in pipeline access should improve the liquidity of trading at hubs, the reliability of hub prices, and in turn provide better signals for pipeline investment, and gas consumption and production. In particular, these recommendations seek to promote shorter-term trades in pipeline capacity trading, which should support the development of liquidity at the Northern and Southern Hub and consequently their ability to generate prices that better reflect short term shifts in supply and demand.

The Commission is also recommending that the actual price of all primary capacity sales, and terms and conditions of those sales which might impact the price, be published. The Commission considers that the additional transparency will lower transaction costs and provide shippers with confidence that access is being provided on a non-discriminatory basis - reducing barriers to entry.

Information to support the market

The Commission's recommended approach to the evolution of gas trading hubs on the east coast is supported by a detailed package of recommendations to enhance the information provided to the market.

An important characteristic of a workably competitive market is that participants have ready access to the information they require to make informed decisions about the prices they expect to see resulting from the market. In gas markets, such pricing expectations are not formed in relation to one specific data point but require a range of information about production and consumption levels, transportation flows, and investment levels in both the short and long run.

A central repository of information for use by all market participants and the public exists in the form of the Natural Gas Services Bulletin Board. The Commission has developed a package of recommendations to improve information transparency, including expanding coverage of the Bulletin Board so that a wider range of information is provided and enhancing the reporting and compliance framework.

To support the continued development of the Bulletin Board to achieve its objectives, the Commission is recommending that a regular review process should be introduced.

Summary of roadmap for market development

Overall, the Commission considers that the gas market development package set out above will promote the Energy Council's Vision and the NGO, and is a proportionate, but meaningful, response to the issues at hand.

A summary of the Commission's recommendations is set out in Table 1, at the end of this summary.

Implementation of the Commission's gas market development package

While the Commission considers that many of its recommendations should be implemented as soon as possible, others will need to be implemented in sequence. Some further measures being considered by the Commission will be contingent on the relative success (or otherwise) of the earlier recommendations. In this way, the Commission envisages that the implementation of the complete package will occur over several phases, forming a roadmap to guide the development of the market over the next decade.

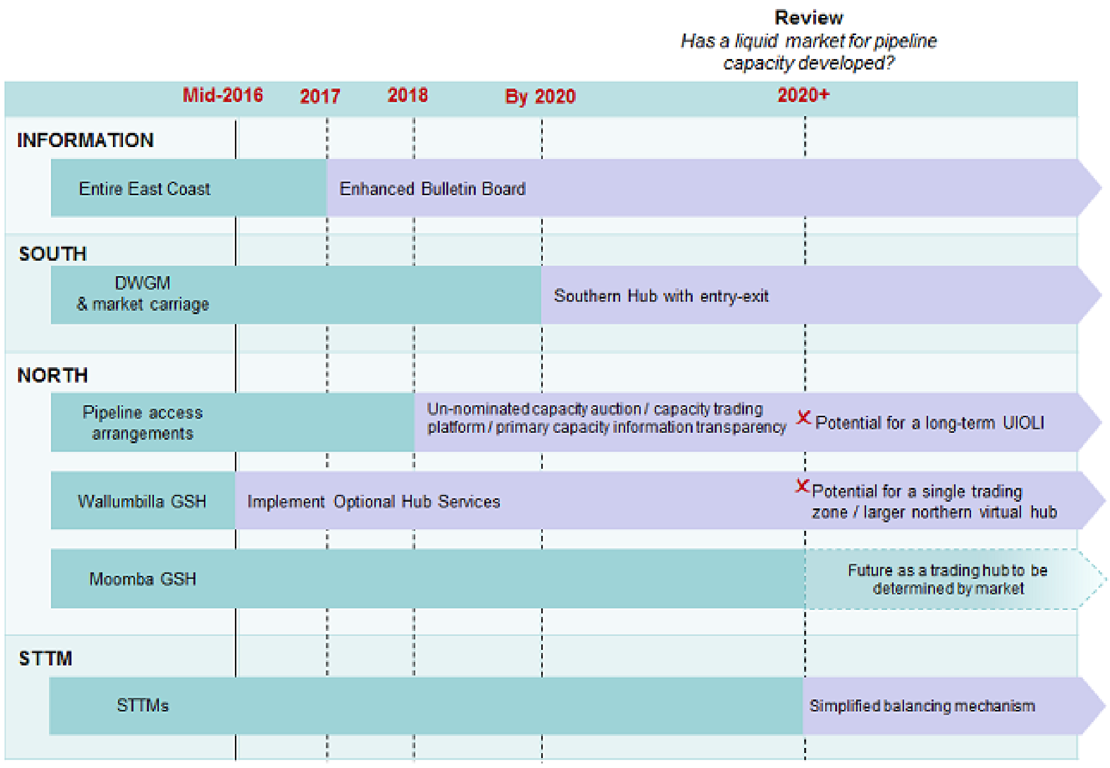
The Commission's current view is that the first phase of reform, to be completed within the next five years, would comprise:

- implementing the recommended enhancements to information provided through the Bulletin Board;
- introducing the recommended mechanisms outlined in Chapter 4 to enhance pipeline access; and
- transitioning the DWGM and market carriage arrangements to the recommended Southern Hub design, including a complementary system of entry and exit rights.

This would be in addition to the work currently being undertaken by AEMO to implement the Optional Hub Services arrangements at the Wallumbilla Gas Supply Hub and establish an additional Gas Supply Hub at Moomba.

An overview of the staging of the overall package is set out in Figure 2 below, which also highlights certain dependencies later in the reform program.

Figure 2 The Commission's recommended roadmap for market development



Over the remainder of the review, the Commission intends to undertake further work to develop its recommendations in more detail. This will include further consideration of how the implementation of the recommendations should be managed. The implementation process may include the formation of a dedicated team to lead and co-ordinate the various elements of the reform roadmap. There may potentially be a role for an advisory panel to provide stakeholder input.

Table 1 Summary of key recommendations

Market development area	Recommendations
Wholesale gas trading markets	Two primary trading hubs on the east coast, one in the north and one in the south, with common trading mechanisms applying to each.
	The Northern Hub to be defined as a physical hub at Wallumbilla, with the potential for a virtual hub at a later date.
	The Southern Hub to consist of a virtual hub covering the Victorian transmission system, with an entry-exit regime for allocating capacity.
	Simplification of the STTM hubs to a balancing role once liquidity has developed at the Northern and Southern hubs and in pipeline capacity trading.
Pipeline access	Introduction of an auction for contracted but un-nominated capacity with a regulated reserve price on all pipelines.
	Mandatory creation of capacity trading platforms, through which information regarding all capacity trades, including prices, must be published. Capacity product standardisation would facilitate trading through the platform.
	Publication of the actual price of all primary capacity sales, and terms and conditions of those sales, which might impact the price.
Information provision	Broaden the purpose of the Bulletin Board in the National Gas Rules to reflect the wider role that information plays in the sector.
	Expand the coverage of the Bulletin Board and improve and strengthen the reporting framework.
	Make the Bulletin Board more responsive to changes in market conditions by removing funding methodology from National Gas Rules and creating a framework to support ongoing improvement.

Contents

1 Introduction

1.1 Context for the review

The gas industry on the east coast of Australia is undergoing a substantial transition. A collection of largely isolated point-to-point pipelines has evolved into a more interconnected network, supporting a series of increasingly interlinked markets.

This process has been significantly accelerated by the commencement of liquefied natural gas (LNG) exports from Queensland. The east coast is currently experiencing an unprecedented increase in overall gas demand, significant shifts in supply and domestic demand with consequential impacts on patterns of gas flows, and changes to prices driven by the influence of international price levels and structures. These factors have led to a renewed focus of market development and supply chain efficiency.

Against this background, the COAG Energy Council 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 is to 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.[5]

The Energy 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").[6]

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 Commission's remit and are being considered by other bodies, with which we are working and consulting.[7]

1.1.1 Changing market dynamics are driving a need for greater flexibility

Historically, gas on the east coast has been traded through long term bilateral gas supply agreements (GSAs). These commonly covered periods of 15 to 20 years or more

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

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

7 In particular, the Australian Competition and Consumer Commission (ACCC) has been tasked with undertaking an inquiry into Eastern and Southern Australian wholesale gas prices (see section 1.8). In addition, at its July 2015 meeting, the COAG Energy Council noted the importance of building and sustaining community confidence in unconventional gas development as a high priority, and agreed to develop and implement a plan on this by the end of the year.

to underwrite investments in long-lived assets. Most GSAs contained take or pay clauses, and prices were generally escalated annually in line with inflation, with provision for periodic reviews.[8]

A number of facilitated gas markets have been developed on the east coast, including the DWGM in Victoria and the Short Term Trading Market (STTM) hubs in Adelaide, Brisbane and Sydney. However, in a relatively stable environment where the majority of gas was transacted through bilateral contracts, their role has mostly been to manage daily imbalances and to facilitate relatively limited amounts of trading at the margin.

This environment is now subject to significant and rapid change. Between 2014 and 2016, gas demand on the east coast will have increased threefold, driven by LNG exports.[9] This substantial increase in demand has put upward pressure on domestic gas prices. In addition, as many export contracts are linked to international oil prices, there has been a growing trend to link domestic gas prices to oil,[10] presenting a new and unfamiliar risk for gas consumers to manage.

As a result of these factors, some retailers and large industrial users have expressed concerns that it is becoming more difficult and expensive to enter into GSAs. As part of its ongoing inquiry into the east coast gas market, the ACCC has reported that, in the period 2012-2014, domestic users were able to secure very few, if any, offers. Since 2014, there appear to have been more offers in the market. However, the resulting gas supply contracts tend to be for considerably shorter durations and at higher prices. They also tend to have much less flexibility around some of the delivery conditions, for instance "banking" gas.[11]

This period of volatility in the market has coincided with the expiry of many domestic long term GSAs,[12] raising questions around the market's resilience to such significant changes. Market participants now require greater flexibility in how they buy and sell gas outside of bilateral gas contracts and new approaches to risk management. The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed.

1.1.2 Flexibility in trading can be supported by liquid markets

Greater shorter term trading of gas will require physical markets that can foster liquid trading and support the development of risk management products, as recognised by the establishment of the Wallumbilla Gas Supply Hub (GSH). Such markets would

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

9 AEMO, *National Gas Forecasting Report*, 2014.

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

11 Sims, R., *The Importance of Adequate Competition for the East Coast Gas Market*, Speech to Eastern Australia's Energy Markets Outlook 2015, 17 September 2015.

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

complement rather than replace the trade of gas through bilateral contracts by providing additional market options to enhance transparency and price discovery.

An effective market is one that can deliver a meaningful reference price. Such a price can provide signals to drive the efficient use of gas in the short term and promote efficient levels of investment in the long term. A credible market price can be referenced in bilateral contracts, making contracting easier and less costly. Using the market price would remove the need for customers to establish their own price expectations and give them confidence that the price they are paying reflects underlying supply and demand conditions.

However, to get an efficient market-based reference price for gas that is credible in the eyes of participants requires sufficient trading liquidity. A liquid market has the following characteristics:[13]

- large numbers of buyers and sellers trading;
- sufficient volumes of gas being traded; and
- low transaction costs to trading.

In a liquid market, individual trades can be easily satisfied and will not cause the price to change significantly. Unless participants are confident that the market price represents the underlying value of gas, then physical and financial counterparties will be unwilling to offer derivatives. This will, in turn, decrease the attractiveness of purchasing gas on the market or indexing a bilateral contract to the market price, as the price risk cannot be effectively hedged. However, developing a liquid trading market on the east coast of Australia is unlikely to be an easy task, given the small number of participants and low volumes compared to developed markets in Europe and the United States (US).

1.1.3 Market frameworks must evolve to help liquidity develop

A critical enabler for the development of liquid gas markets, particularly in an environment with few, geographically dispersed producers and users, will be the ability of gas to flow easily across the pipeline system to where it is most highly valued. If there are obstacles to participants being able to access transportation capacity, this will inhibit their ability to move gas to market and trade it, diminishing liquidity.

Existing gas transportation arrangements based around long term bilateral contracts have supported substantial investment in pipelines,[14] but the significant increase in the volatility of flows beginning to be experienced on the transmission network is highlighting the lack of flexibility embodied in these arrangements. For instance, the

13 FTI Consulting, *Conceptual Design for a Virtual Gas Hub(s) for the East Coast of Australia*, November 2015, p. 8.

14 Different arrangements for investment in pipelines apply in the DWGM. See: AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2015, Chapter 2.

potential for outages at the LNG production facilities, combined with the variable nature of the coal seam gas wells supplying them, will lead to occasions where significant amounts of gas will need to be redirected to different uses and to users who would value the gas most highly.

While we understand that the rights to use pipeline capacity are sometimes reallocated between participants for periods of 6-12 months, we have seen little evidence that shorter-term capacity trades occur. Indeed, we have heard that the transaction costs involved in such trades can be prohibitive. While pipeline owners can and do resell unused short term capacity, the lack of competition in this market provides few limitations on the price set for access.

Consequently, inefficiencies in the market for short term pipeline capacity are likely to represent a major barrier to the development of liquid trading markets with prices that can respond to short term shifts in supply and demand. Much of the Commission's work in the review, therefore, has been to understand this linkage between capacity and commodity markets, and to identify opportunities to develop the frameworks to allow pipeline capacity to be reallocated in ways that would support the trading of gas.

To complement this, we have also considered options for the location and design of facilitated wholesale markets. Liquid trading is most likely to develop where there is a diversity of producers and users, and potentially other services that facilitate trading (such as storage). This implies that the existing STTM hubs, located at capital cities, are unlikely to be the best locations to seek to develop liquid trading markets. Similarly, the current STTM design, which mandates that all physical trading takes place only on a day-ahead basis, does not provide options for flexible trading and is unlikely to support the development of risk management products.

For markets to function efficiently they require participants to have accurate and timely information to aid decision making. This allows participants' preferences to be acted upon, and informed trade-offs to be made. Market outcomes will partially be a function of the information on which participants are able to act, and this is therefore also an important consideration in the development of market frameworks.

Consequently, consistent with the terms of reference for the review, this report sets out the Commission's draft recommendations to support improved price discovery and liquidity in wholesale markets. Underpinned by enhancements to regulatory frameworks to facilitate the more efficient usage of pipeline capacity, these measures would put in place the preconditions to allow more effective risk management tools to develop.

In addition, we have thoroughly reviewed the frameworks for information provision in the context of the current market arrangements. Chapter 6 summarises our findings in this regard, with our full recommendations set out in a separate report, reflecting the more detailed and immediate nature of this work.[15]

15 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report: Information Provision, December 2015.

1.2 The East Coast Gas Market and Pipeline Frameworks Review

As indicated above, the Commission was tasked in this review to consider the design, function and roles of facilitated gas markets and gas transportation arrangements in eastern Australia. We were requested to develop specific actions that can be implemented to strengthen the structure and competitiveness of the eastern Australian market and asked to make recommendations for immediate implementation, where possible.[16]

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.

The East Coast Review has been structured over two stages:

- Stage 1 outlined the overall direction for the east coast market development, including a factbase of current market outcomes and a gap analysis between the COAG Energy Council's Vision for Australia's future gas market and the existing arrangements, as well as setting out a number of recommendations that could be progressed in the short term (see section 1.8); and
- Stage 2 more fully develops 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 AEMC has also been asked by the COAG Energy Council, at the request of the Victorian Government, to examine the DWGM specifically to assess whether reforms are required to enhance the liquidity, transparency and flexibility of the current arrangements.[17]

In summary, the terms of reference for the review require the Commission to consider:

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

17 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.

- 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. As such, the AEMC and the Victorian Government agreed to combine the initial phase of the DWGM review with Stage 1 of the East Coast Review.

However, in the second phase of the review, we have considered the DWGM in greater detail and are making recommendations that would only initially be applied to the DTS. Consequently, these matters are presented in a separate, complementary report that focuses specifically on the DWGM review.[18] The full terms of reference are also provided as an appendix to that report.

1.4 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference, the AEMC must have regard to the Energy Council's Vision for Australia's future gas market and Gas Market Development Plan. Specifically, the Energy 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 promote the Energy Council's Vision for Australia's future gas market, which is as follows:[19]

> "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."

18 See: AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2015.

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

The Vision is underpinned by four broad policy work streams and related outcomes:[20]

1. Encouraging competitive supply.

2. Enhancing transparency and price discovery.

3. Improving risk management.

4. Removing unnecessary regulatory barriers.

Overall, the Vision provides the Commission with a high level policy statement to guide its analysis through the review. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the National Gas Objective (NGO).

1.5 National Gas Objective

The terms of reference also specify that the Commission must consider the NGO. The NGO underpins all of the Commission's work and is set out in section 23 of the National Gas Law (NGL). It 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:[21]

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.

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20 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/

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

In accordance with the NGO, the Commission will take into account the long term interests of all consumers of natural gas throughout this review. We note 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.

1.6 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:[22]

- 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 ACCC inquiry and AEMC reviews are complementary, with the ACCC having much broader information gathering powers than the AEMC. We are working closely with the ACCC to ensure that the two processes are co-ordinated, and to understand the extent to which the ACCC's findings on the above issues can help to inform our considerations regarding market development.

Under section 157A of the Competition and Consumer Act, the ACCC may disclose to the AEMC information that it has obtained under the Act that is relevant to the AEMC. The two organisations have therefore put procedures in place to allow such information to be shared in this instance.

The ACCC published an issues paper for the review on 4 June 2015, and has since held formal hearings. The inquiry is to be completed by April 2016. We currently intend to provide the final report for this review to the Energy Council in May 2016 so that it is able to reflect the ACCC's findings.

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

1.7 Review process

1.7.1 Project dates and consultation

This is the Draft Report for Stage 2 of the East Coast Review, which has been produced for the consideration of governments and consultation with the broader stakeholder community. It follows the submission of the Stage 1 Final Report to the Energy Council in July 2015, which contained a number of shorter-term recommendations. The Commission has taken a highly consultative approach in conducting both the East Coast and DWGM reviews, as summarised in the table below.

Table 1.1 Review process

Date	Milestone	
	East Coast Review	**DWGM Review**
20 February 2015	Terms of Reference	
25 February 2015	Public Forum and Discussion Paper	
4 March 2015		Terms of Reference
7 May 2015	Stage 1 Draft Report	
23 July 2015	Stage 1 Final Report	
6 August 2015	Wholesale Gas Markets Discussion Paper	
10 September 2015		DWGM Discussion Paper
18 September 2015	Pipeline Regulation and Capacity Trading Discussion Paper and Information Provision Working Group Discussion Papers	
30 September 2015	Public Forum	
4 December 2015	**Stage 2 Draft Report**	DWGM Draft Report
May 2016	Stage 2 Final Report	DWGM Final Report

In addition to the documents and forums listed above, a working group was established to consider issues related to information provision, which met on four occasions between August and October 2015 and was supported by a number of working papers to develop the issues and proposed solutions.

The Commission appreciates the time and effort required to prepare submissions and attend meetings, particularly over such condensed timeframes, and thanks stakeholders for engaging with the Commission throughout the review process.

Box 1.1 Implementation of Stage 1 recommendations

In the Stage 1 Final Report, the Commission recommended four measures that could be progressed in the short term to address a number of immediate issues identified in the first stage of the review. The following provides a brief update on the current status of these initiatives.

1. Introduction of a wholesale gas price index

The Commission recommended that greater transparency on wholesale gas prices would be useful as a transitional measure until there is an efficient reference price available for market participants and other interested parties. Our preferred approach was to work with the Australian Bureau of Statistics (ABS) to develop a survey-based gas price index that would measure the trends in prices payable under bilateral contracts over time.

The index would be compiled as an extension of the existing Producer Price Index by surveying large gas users that purchase gas directly from producers, including industrial users, gas-fired generators, retailers and LNG producers. While it would not reveal absolute price levels, the index would provide greater transparency around the direction and magnitude of changes in the price of confidential GSAs.

To progress this recommendation, the Commission has led a process to engage with the ABS and industry. Stakeholder workshops were held in Sydney and Perth on 18 August and 14 September, respectively. In total, around 70 stakeholders registered to attend from industry, governments and energy market institutions. The purpose of the workshops was to facilitate a discussion between ABS staff and industry around methodology, data collection, confidentiality arrangements and other issues associated with compiling the index.

The Commission has been encouraged by the support from industry to date in progressing this initiative. Feedback to the Commission at the workshops was that this is an important transparency initiative and appropriate consultation needed to take place in order for industry to have confidence in the methodology. We also understand a number of stakeholders have approached the ABS directly and offered their assistance and support.

The Commission understands the ABS will publish an information paper on 7 December 2015 setting out potential options for developing a wholesale gas price index. The paper will discuss potential methodologies that could be used and the benefits and trade-offs of different approaches.

To provide industry with an opportunity to engage with the ABS on this document, the AEMC will be facilitating another round of stakeholder workshops in Sydney and Perth in early 2016. The ABS should be in a position to provide guidance on the implementation timeframe for the index on completion of this consultation.

2. Rule change to harmonise the gas day

Trading of gas is conducted over "gas days", and the timing of these currently differs across the east coast.[23] The Commission recommended that the Energy Council submit a rule change to the AEMC to introduce a consistent gas day start time. Harmonising the timing of gas days may remove some of the complexity for parties that operate across multiple markets and assist the process of increasing interoperability across markets.

The Energy Council agreed at its July 2015 meeting to submit the rule change, and it has since been developed by Council officials. The AEMC received the rule change request in late November and will progress it in due course.

3. NGL amendments to allow any party to propose a DWGM rule change

The NGL currently provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[24] The Commission recommended that this restriction be removed, on the basis that it may represent a barrier for some market participants to influence market development and is inconsistent with the governance applying to other gas and electricity markets.

The Council also agreed to this measure at its July 2015 meeting. We understand that officials are progressing the legislative amendment as a component of a number of legislative packages scheduled for 2016.

4. Address additional information gaps through the Enhanced Information for Gas Transmission Pipeline Capacity Trading rule change

On 16 July 2015, the AEMC commenced consultation on a rule change received from the Energy Council to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board. In the Stage 1 Final Report, the Commission noted that it would consider whether there were any other informational gaps that fell within the scope of the rule change. The report raised the possibility of considering suggestions made by stakeholders for additional information on storage facilities and volumes, and data on linepack, as well as potential improvements to medium term capacity outlook information.

On 1 October 2015, the Commission made a draft determination[25] which requires additional reporting by storage facilities and the use of a standard format for medium term capacity outlooks. The Commission is due to make a final determination before the end of 2015.

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23 Gas days start at 6:00am in Victoria, 6:30am at the Sydney and Adelaide STTM hubs, and 8:00am at the Brisbane STTM hub and Wallumbilla gas supply hub.

24 Victoria is currently the only adoptive jurisdiction.

25 AEMC, *Enhanced Information for Gas Transmission Pipeline Capacity Trading*, Draft Rule Determination, 1 October 2015.

1.7.2 Advisory group

As required by the terms of reference, the Commission has established an Advisory Group that operates across both the East Coast and DWGM reviews. This group provides strategic advice and expertise to the Commission over the course of the review. It meets periodically and is chaired by John Pierce, AEMC Chairman. 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)

1.7.3 Submissions to this report

The Commission welcomes submissions in response to the findings and draft recommendations set out in this report. The closing date for submissions is **Friday, 12 February 2016**.

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.

1.8 Structure of this report

The next two chapters of this report are structured as follows:

- Chapter 2 provides a case for change to the current market arrangements. It explains how recent developments in the east coast gas sector have meant that existing arrangements are no longer fit-for-purpose; and
- Chapter 3 provides a summary of the Commission's overarching findings and recommendations in order to achieve the Vision.

The following three chapters provide more detailed explanations of the Commission's findings and recommendations on:

- pipeline capacity markets (Chapter 4);
- wholesale gas markets (Chapter 5); and
- the operation and relevance of the Bulletin Board (Chapter 6).

Chapter 7 discusses the implementation of the Commission's recommendations and next steps for this review.

Finally, the report also contains three appendices, as follows:

- Appendix A: Terms of Reference;
- Appendix B: The Commission's assessment framework; and
- Appendix C: Summary of stakeholder submissions.

A separate report setting out the Commission's detailed draft recommendations on information provision and the Bulletin Board accompanies this Draft Report and can be found on the Commission's website.[26]

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26 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report: Information Provision, December 2015.

2 Compelling case for change

Box 2.1 Summary of findings

As has been well documented, the eastern Australian gas market is experiencing a period of growth and change. The establishment of a Queensland-based LNG export industry is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows.

The development of the LNG export industry, combined with the growing maturity of the east coast market, is altering the way gas and pipeline capacity is bought and sold. Historically, bilateral gas and transportation contracts, often with terms of 15 to 20 years, were used as the primary means of trade. This is an entirely appropriate way of mitigating the risks associated with specific, capital intensive assets, and minimising transaction costs in a market with only a small number of participants and relatively predicable gas flows.

While bilateral contracts will remain a fixture of the market, into the future industry participants are likely to require more flexible and sophisticated ways of managing their gas portfolios. This will likely be due to:

- rising gas supply agreement (GSA) contract prices, inducing participants to reduce their average gas supply costs through market-based trading;
- reduced load factor flexibility in GSAs and/or flexibility priced at a premium, providing an incentive to utilise trading markets to procure flexibility; and
- spot price volatility, resulting in arbitrage opportunities that participants seek to benefit from.

In the Commission's view, these factors highlight the importance of achieving the COAG Energy Council's Vision. Achieving the Vision will provide participants with greater flexibility when buying and selling gas, and should promote an increase in wholesale market competition. Competition facilitates the process by which gas is allocated to those users who value it the most, promoting efficient wholesale market outcomes that benefit consumers through lower retail prices.

The Commission notes that transition currently underway in the east coast market presents an opportunity to develop a liquid wholesale gas market. As Energy Ministers noted at their July 2015 meeting, the "gas market is entering a new era of dynamism, and the imperative was to get the fundamentals right to prepare market participants for new ways of price discovery, trading, investment and risk management".[27]

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27 COAG, *Energy Council Meeting Communique*, 23 July 2015, p. 2.

2.1 How the east coast gas market is changing

The eastern Australian gas market is experiencing a period of growth and change. The establishment of a Queensland-based LNG export industry is triggering unprecedented shifts in supply and demand and, consequently, changes in patterns of gas flows. While bilateral contracts will remain a fixture of the market, into the future industry participants are likely to require more flexible and sophisticated ways of managing their gas portfolios. This will likely be due to:

- rising gas supply agreement (GSA) contract prices, inducing participants to reduce their average gas supply costs through market-based trading;
- reduced load factor flexibility in GSAs and/or flexibility priced at a premium, providing an incentive to utilise trading markets to procure flexibility; and
- spot price volatility, resulting in arbitrage opportunities that participants seek to benefit from.

These factors, which are discussed further below, highlight the importance of achieving the COAG Energy Council's Vision.

Achieving the Vision will provide participants with greater flexibility when buying and selling gas, and should facilitate an increase in wholesale market competition. Competition facilitates the process by which gas is allocated to those users who value it the most, promoting efficient wholesale market outcomes that benefit consumers through lower retail prices.

2.1.1 Upward pressure on GSA contract prices

Concurrent to the Commission's East Coast and DWGM reviews, the Australian Competition and Consumer Commission (ACCC) is conducting a formal inquiry into the east coast gas market. Rod Sims, Chairman of the ACCC, recently noted that "gas supply contracts now tend to be for considerably shorter duration and at higher prices".[28]

While the ACCC's preliminary findings suggest that LNG exports have resulted in a tightening in the supply and demand balance and upward pressure on wholesale gas prices, this should provide an incentive for producers to offer more supply to the market. However, restrictions on gas supply, or inquiries into gas field development, which currently exist in a number of jurisdictions could restrict this response, resulting in higher wholesale prices than would otherwise have been the case.[29]

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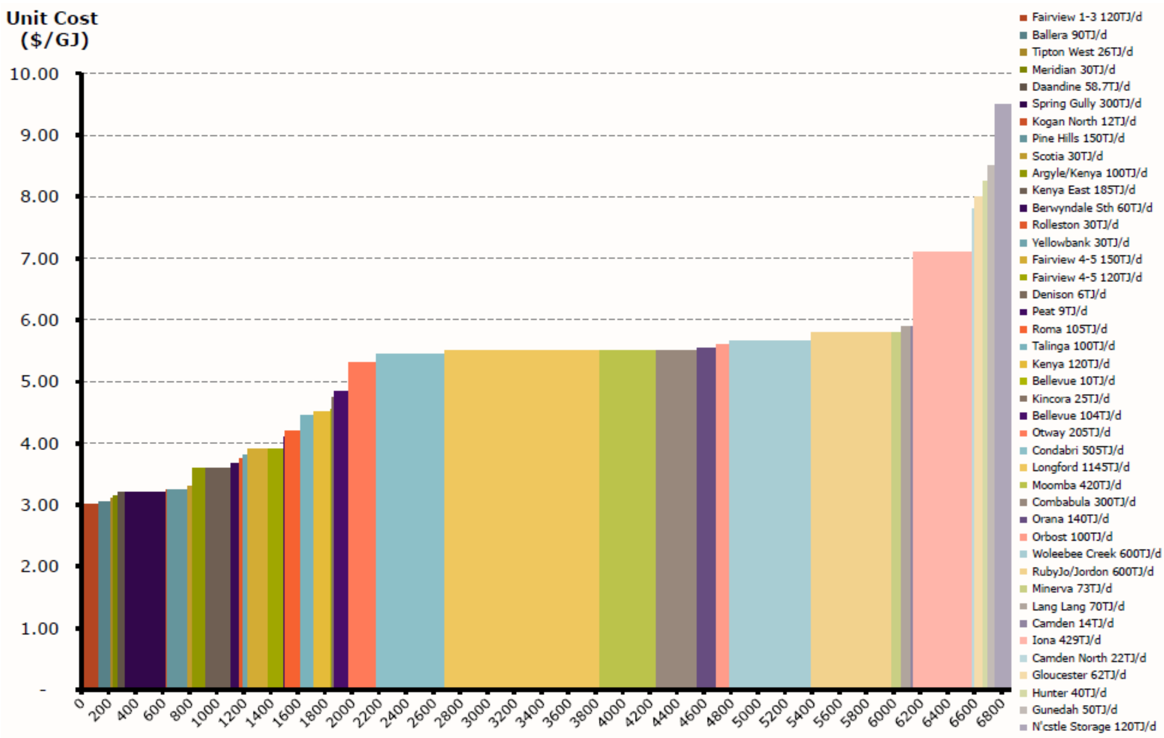
28 Sims, R., *The importance of adequate competition for the east coast gas market*, Speech at the Eastern Australia's Energy Markets Outlook 2015, 17 September 2015. See: https://www.accc.gov.au/speech/the-importance-of-adequate-competition-for-the-east-coast-gas-market

29 Restrictions on gas supply or inquiries into gas field development currently exist in New South Wales, Victoria, South Australia and Tasmania.

The Commission notes that higher gas costs from developing less productive or more expensive gas reserves will also contribute to higher prices paid by consumers.

Figure 2.1 shows an indicative gas supply cost curve for the east coast market. The horizontal axis shows the maximum theoretical quantities capable of being produced by each supplier (TJ/day), while the vertical axis shows cost of production ($/GJ). As lower cost gas reserves are developed and consumed, higher cost reserves will need to be brought online. This means that, unless there is a change in technology that lowers extraction costs, an increase in supply in response to higher prices may not result in a reversion back to historic price levels due to increased production costs.

Figure 2.1 Indicative east coast gas supply cost curve



Source: Simshauser, P. & Nelson, T. 2015,*The Australian east coast gas supply cliff*, Economic Analysis and Policy, p. 78.

2.1.2 Reduced flexibility in GSAs

Another preliminary observation by the ACCC is that there has been a reduction in the level of flexibility traditionally afforded to buyers under long term GSA contracts. The ACCC has provided insight on this in the following way:[30]

> "The current contracts also have much less flexibility around some of the delivery conditions. As an example, a contract struck today for the supply

30 Sims, R., *The importance of adequate competition for the east coast gas market*, Speech at the Eastern Australia's Energy Markets Outlook 2015, 17 September 2015. See: https://www.accc.gov.au/speech/the-importance-of-adequate-competition-for-the-east-coast-gas-market

of gas may be only for one, two or three years. It may have some form of oil price linkage. It may also have a lower limit of liability for a producer's non-performance in the delivery of gas, coupled with a higher obligation on the buyer to take or pay the contracted quantities."

GSAs traditionally include a degree of flexibility in the quantity of gas a buyer can take on any day to cater for variability in their demand. Specifically, such contracts usually include a "take or pay" amount that the buyer must take or else they will be charged for that amount regardless, as well as a load factor that measures the extent to which a buyer can take more than the average daily contract quantity throughout the year. The take or pay provisions may also include a "make-up" provision, allowing a user to take gas at a later date that is not used in the current period.

The load factor typically ranges from 100 to 125 per cent. A value of 100 per cent implies the buyer can only take its average daily contract quantity; while a value of 125 per cent implies that the buyer can vary its daily consumption by +/-25 per cent on any day, subject to the constraint that it only takes its annual contract quantities over the year.[31]

However, flexibility in GSAs can be expensive for producers, as the production facility, and associated capital, is underutilised outside peak periods. With the start of LNG exports, and consequent increase in demand, producers may seek to run their plants at higher capacity factors in the future and become more reluctant (ie, would charge a higher price) to offer bilateral contracts to gas users with the amounts of supply flexibility traditionally offered.

If this trend propagates, it will increase the importance of developing a liquid trading market to:

- allow shippers to easily sell additional contracted gas outside of their peak periods; and
- provide a mechanism for shippers to purchase gas on a short term basis to meet their peak demand.

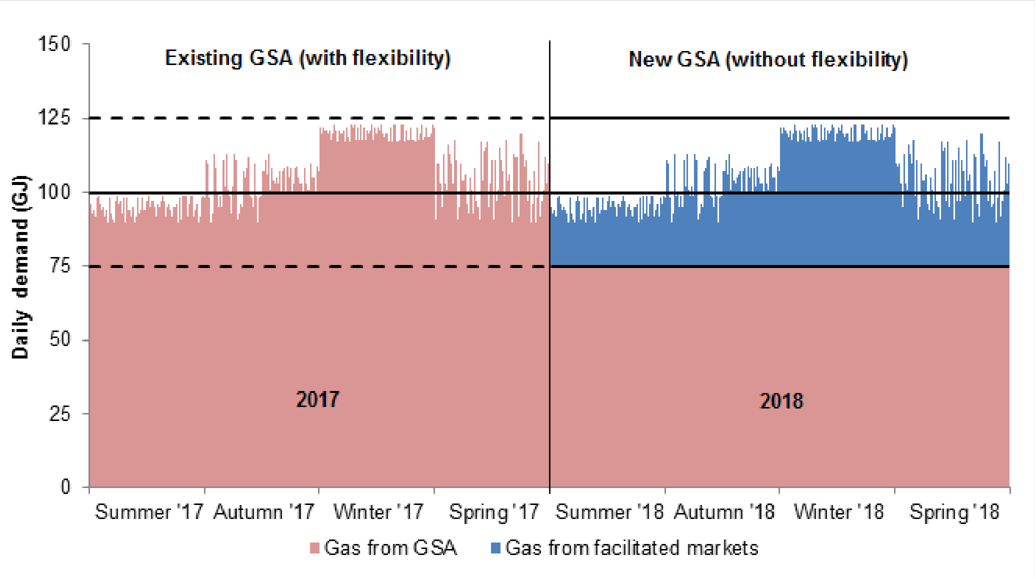
Buyers who wish to manage their gas demand outside of a GSA need to find a balance between a minimum level of gas sourced through bilateral contracts, with the remainder sourced through market trading. This is illustrated in Box 2.2.

31 K Lowe Consulting, *Gas Market Scoping Study: A report for the AEMC*, July 2013, p. 43.

Box 2.2 Reduced flexibility in GSAs will support trading liquidity

The figure below illustrates the demand for gas by a representative market participant over a two year period, where the first year (2017) they are counterparty to the type of GSA traditionally offered by producers on the east coast. In the second year (2018) they have had to enter into a GSA with less flexibility or load factor. The representative market participant in this stylised example can be thought of as a retailer who sells gas to small commercial and residential consumers and expects to have a peak demand for gas corresponding to the winter months.

Figure 2.2 Sourcing of gas supplies under GSAs of different flexibility



The retailer has an average expected daily demand of 100GJ, which is reflected in the average daily contract quantity for 2017 (the solid black line). The existing contract includes swing factors (flexibility) to allow the participant flexibility of +/-25 per cent, ie, so that they can take anywhere between 75 and 125GJ per day under the contract. As illustrated in this stylised example, this results in the participant being able to procure all of its required gas from within the confines of its contract.

Under the new type of GSA, this amount of flexibility may no longer be available or is available at prohibitively high cost. Participants may therefore decide to:

1. Continue to have a GSA for expected average daily demand and buy or sell gas around this in the spot of forward markets as required. This is illustrated by the solid black line corresponding to 100GJ per day in 2018.

2. Enter into a GSA for delivery of gas at a fixed price to meet expected *maximum* demand and sell any excess gas on a trading market in the spot of forward markets. This is illustrated by the solid black line corresponding to 125GJ per day in 2018.

3. Enter into a GSA for delivery of gas at a fixed price to meet expected *minimum* demand and rely on buying gas from the trading market to satisfy demand above this minimum level. This is illustrated by the solid black line corresponding to 75GJ per day in 2018.

Importantly, under all options, the participant will seek to trade on the spot and forward markets more under a less flexible GSA contract. In addition, the participant would be able to lock in forward prices for the gas in a liquid market.

In the stylised example above, the participant opts to only contract for 75GJ of expected average daily demand of 100GJ. The blue area in the figure therefore shows the amount of gas the participant is aiming to procure through short term trading.

2.1.3 Spot price volatility

The large amount of gas required for LNG export operations, combined with the variability inherent in CSG supply, is from time to time likely to result in price differentials across the east coast market. Price volatility is likely to:

- provide participants with commercial opportunities to arbitrage gas prices between trading markets on the east coast, as well as between their bilateral contract price and trading market prices; and
- increase the demand for financial derivatives to manage the increased price risk on the trading markets.

Price volatility can be profitable for participants prepared to take advantage of opportunities at short notice. Where the gas price is low and participants are able to substitute contract gas with spot gas, inject gas into storage and/or build inventory by increasing production at a factory, this promotes the efficient allocation of gas in response to price signals. Examples where this type of trade is likely to emerge are set out in section 2.3.

The corollary of using trading markets more actively to procure supply flexibility, and as a credible alternative to bilateral contracts, is a greater exposure to market prices. While participants may have been comfortable managing spot price risk within the flexibility of a physical GSA position, in the future this may not be possible.[32] As a consequence, there is likely to be a greater need for market-based financial derivative products to hedge price risk from market-based trading.

32 For a discussion on managing market price risk through a GSA, see: AEMC 2015, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, Wholesale Gas Markets Discussion Paper*, 6 August 2015, Sydney, p. 9.

2.2 Meeting the Vision will benefit consumers and is achievable

The Vision as set out by Energy Council focuses on key outcomes for the gas market that are necessary to meet the NGO. These include encouraging competitive supply; enhancing transparency and price discovery; improving risk management and removing unnecessary regulatory boundaries. The Vision provides a high level policy statement that has guided the analysis undertaken in this review, along with the NGO.

The achievement of the Vision is an important objective given the changes occurring in the gas market and the likely inability of the current market arrangements to accommodate these changes. This section examines the number and type of participants in the wholesale gas market across the east coast. It shows that the Vision is expected to be achievable, particularly given the transformation that is occurring in the east coast gas market.

2.2.1 Benefits of a liquid wholesale gas market

A liquid wholesale gas market encourages participation by both producers and users of gas. The nature of such a market provides many benefits, including information provision, minimised transaction costs and minimised barriers to entry.

Market outcomes are also a function of the quality of information available to market participants. A liquid gas market in which the reference price is an accurate reflection of the value of gas aids commercial decision-making. Where accurate information is available it allows market participants to act upon their preferences and allows for trade-offs to be accurately assessed. A liquid forward and future market also provides market participants with useful information on expectations of future price developments and allows them to formulate appropriate strategies to manage risks.

Importantly for the Australian context, a liquid wholesale gas market can lower barriers to entry and encourages new entrants on both the supply and demand side of the market. Where gas and pipeline capacity is sold predominantly through bilateral contracts, it may be difficult for new producers or gas users to enter the market, as they may not have the required knowledge or financial size to negotiate on an equal basis with incumbents. In a liquid market, new entrants - whether they may be small producers or gas users - have accurate price information and can readily buy or sell gas on a market on an equal basis to other players. Liquid markets can therefore encourage participation and promote competition.

Similarly, a liquid market can reduce transaction costs as buyers and sellers are matched on the market. This reduces search costs as sellers and buyers no longer need to incur the costs associated with searching for and negotiating an agreement with a counterparty. Buyers and sellers in a liquid market can trade frequently at low cost and at a price that is reflective of the "true value" of gas based on underlying supply and demand dynamics.

It is clear from the discussion in section 2.1 that the gas market is undergoing fundamental change, which is likely to have the following implications for the market:

- The potential lack of flexibility in GSAs in the future will mean that more gas will be procured through trading markets.

- The shorter term nature of gas contracts will mean that market participants will need to engage in a larger number of transactions to satisfy their demand for, or sell their supply of, gas.

- Gas users, who have previously sourced all their gas demand through bilateral contracts, may now trade on a market for the first time - increasing the number of market participants.

- The number of trades on wholesale gas trading markets is likely to increase.

Increased use of, and demand for, market-based trading is likely to have some important implications:

- An increased number of traded transactions provides market information about the underlying supply and demand balance.

- Price-setting becomes more transparent with this increase in market information.

- As trading becomes more commonplace, flexibility in long term contracts becomes less relevant as such flexibility is available on markets.

- A market price that accurately reflects underlying supply and demand conditions can provide effective signals to market participants.

- Confidence in the accuracy of the market prices would increase and market participants will be willing to act in response to price signals.

- Market participants are more willing to participate in the gas market in response to price signals.[33]

As more gas is traded on the market, participants will have confidence that the market price is a reflection of the true value of gas. As market-based trading becomes more common place, corporate experience in trading gas will grow, fostering a trading mindset as is common in other commodity markets.

2.2.2 Number and type of gas market participants can facilitate a liquid market

A liquid wholesale gas market requires different types of buyers and sellers transacting sufficient volumes of gas to support trading liquidity. In practice, this implies that participants use gas in different ways and therefore have incentives to trade with each other in response to a common price signal.

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33 For example, a large gas user who traditionally purchased gas through bilateral contracts may wish to participate more fully in the market by trading in gas in response to price signals. In this way the participant would seek to arbitrage gas prices in a way that they had not done previously.

The east coast gas market is made up of many different players from numerous industries and gas is used in a variety of ways by these participants. The amount of gas used by each participant is dependent on their particular circumstances.[34] Common consumption profiles for gas users include:

- **Residential customers:** Consumption of gas by residential customers can be variable in areas subject to a distinct seasonal influence. Gas demand will be higher in winter and therefore demand can be volatile at this time of year. In areas with a more temperate climate, gas demand is more stable throughout the year. Households purchase gas from retailers who participate in the wholesale gas market; these retailers may therefore have a variable demand profile.

- **Large industrial consumers:** Generally these consumers have a relatively flat consumption profile. However they may have the ability to change the level of production at their facilities and could therefore increase or decrease their demand for gas. These customers are influenced by conditions in the market for their products but are also affected by input costs, including the wholesale price of gas. This category of gas users includes LNG producers.

- **Mining facilities:** These gas users can have a "lumpy" gas consumption profile, meaning that consumption levels can increase or decrease by a large amount at short notice. Mining facilities trade on international commodity markets and must be able to react to changes on these markets.

- **Gas-fired generators:** The consumption profile of a particular generator is dependent on its type. A base-load gas-fired generator will have a relatively flat consumption, as it is regularly in use. A peaking generator may only be used on a few occasions over a year, when electricity demand is very high; for these generators the consumption profile for gas would be volatile.

Market participants' consumption profiles vary in different ways over time. A liquid wholesale gas market allows these diverse market participants to balance their gas requirements while providing commercial opportunities to trade on the wholesale market.

In addition, each jurisdiction on the east coast exhibits fundamental differences in gas usage. These jurisdictional differences in gas consumption can provide additional opportunities to trade and complement the variability in demand profiles between market participants and is demonstrated in the box below.

34 K Lowe Consulting, Gas Market Scoping Study: A report for the AEMC, July 2013.

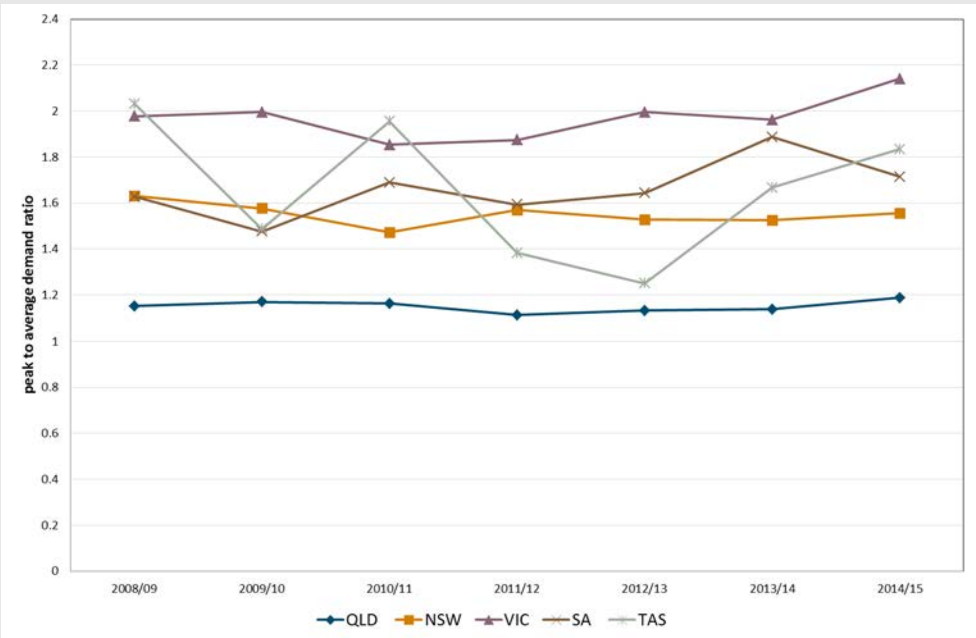
Box 2.3 Changes in demand profiles across jurisdictions

The differences between jurisdictions' demand for gas is based on how gas is used in that region; for example, how large the residential and small to medium enterprise sector is relative to gas-fired generation or industrial users. The weather also has an effect on regional demand profiles, as gas is used to heat homes and business, and conditions can affect electricity demand, which has an indirect effect on gas prices through demand from gas-fired generators.

Figure 2.3 shows the peak demand to average demand ratio for jurisdictions on the east coast. Victoria, with its large proportion of residential gas consumers, has the highest peak to average demand ratio due to the increase in gas demand in winter months. Queensland has the lowest ratio, as gas demand is largely attributable to industrial users with relatively flat consumption profiles.

These seasonal differences make it important for gas to be able to flow efficiently between jurisdictions. When electricity demand in Queensland is high in the summer months, this will drive an increase in gas used for gas-fired generation. Conversely, when the weather is cold in Victoria during winter months, this will drive gas demand for space heating. An interconnected system where gas and pipeline capacity is easily tradeable allows demand for gas to be met at least cost.

Figure 2.3 Ratio of peak to average gas demand by jurisdiction, 2008-2015



Source: AER Wholesale Statistics.

2.2.3 A range of participants exist with varying gas demands

In a market made up of a large number of diverse participants, there are many opportunities to trade. This is because the consumption profiles, and therefore the demand for gas, of different market participants will vary over time. Put simply, at times where retailers, for example, have increased demand for gas, other market participants such as industrial users or gas-fired generators may be able to provide gas to the market.

In a liquid market, bilateral contracts would still be used to source some of the buyer's gas demand. These contracts would follow the traditional supply chain for gas. Large gas users such as retailers, large industrial facilities and gas-fired generators would contract directly with producers for supply. Smaller gas customers do not have sufficient scale to contract directly with gas producers and instead would buy gas from aggregators, such as larger retailers. Examples of users who may contract gas in this way include small industrial facilities and small retailers.

In addition to gas sourced through contracts, market participants also have the opportunity to source gas on traded markets in order to balance their gas requirements. Balancing may involve buying additional gas on the market or selling excess gas to other participants. Producers also have the opportunity to participate in market trading and may do so in order to sell additional gas in response to price signals.

A graphical representation of this market structure is represented in Figure 2.4. Each participant can engage in market trading, in accordance with their needs and in response to price signals. Trading markets do not fully replace GSAs, but are an additional means of buying and selling gas. Because each participant can engage in buying and selling on the market with any other participant, gas can be traded up and down the traditional supply chain.

The numerous trading activities that can be employed by market participants mean that a multitude of potential trades are possible between any number of combinations of participants, in response to price signals. Further, gas can be traded multiple times between each participant before being used. This fosters a dynamic and liquid market where participants can continually trade gas to optimise their portfolios.

Figure 2.4 East coast gas market structure

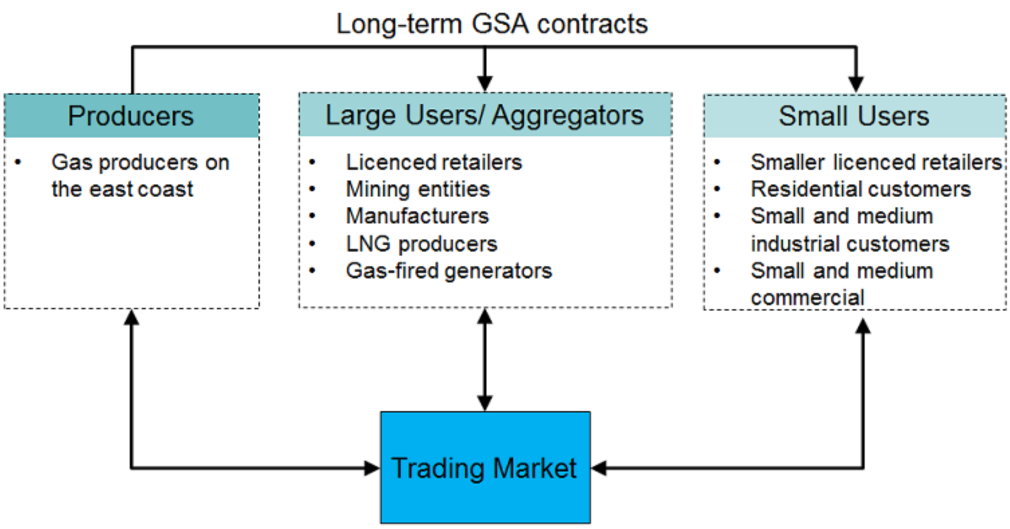


Table 2.1 at the end of this chapter lists the major gas users on the east coast, categorised by gas retailers, large industrial customers (including LNG producers) and gas-fired generators. There are around 45 unique businesses listed across the three categories of users. A number of large gas users are also producers and would be able to participate on both the buy and sell side of transactions on a trading market.

As large users are required to utilise the DWGM and STTM hubs at the major demand centres of Adelaide, Brisbane, Melbourne and Sydney, registration at these markets also indicates the number and type of participants. At the time the Wholesale Gas Markets Discussion Paper was released in August 2015, it was estimated that there were:[35]

- over 50 market participants in the DWGM;
- 16 market participants in the Sydney STTM hub;
- 11 market participants in the Adelaide STTM hub; and
- nine market participants in the Brisbane STTM hub.

The Commission considers that the number of east coast gas market participants is likely to be sufficient to support a liquid wholesale gas market. In the Victorian region of the NEM for example, which is considered to be liquid wholesale market for electricity, there are around 25 individual participants on the demand side of the market and around 15 on the supply side of the market.[36] With a number of legacy GSAs rolling off over the next two to three years, and higher priced and less flexible GSAs being offered by suppliers, the number of large users seeking the flexibility provided by trading markets is likely to increase.

The Commission has already received feedback through submissions from major users that the current facilitated markets are adding value to their gas procurement activities. For instance, Visy, Qenos, Australian Paper and CQ Partners have all submitted that the existing facilitated markets play an important role in providing major users access to wholesale gas at the city-gate.[37]

However, the Commission notes that for trading to continue to grow, participants will require mechanisms to manage risk other than through flexibility in GSAs. One of the ways to do this is through financial risk management products. For these to emerge, it is imperative to get the physical market right so that liquidity can grow to a level where physical and financial participants have sufficient confidence in the price signal. Further discussion on trading market design and risk management is in Chapter 5.

35 AEMC, *Wholesale Gas Markets Discussion Paper*, 6 August 2015, p. 17.

36 Data sourced from AEMO wholesale and retail registration lists.

37 Wholesale Gas Markets Discussion Paper submissions: Visy, pp. 4-5; and Qenos, pp. 2-4. Stage 1 Draft Report submissions: Australian Paper, pp. 2-3; and CQ Partners, pp. 1-3.

2.3 Robustness of a liquid wholesale gas market on the east coast

This section outlines how participants in a liquid wholesale gas market could react to price changes from a variety of sources. The analysis shows that shocks to this sector can have large price effects, but in a liquid wholesale market, participants have the ability to trade and partially mitigate these effects to a greater degree.

Other factors can also have an effect on the wholesale price of gas, including weather events and conditions in other markets, for example the wholesale electricity market. Again, the existence of a liquid wholesale gas market provides opportunities to trade and respond quickly to market developments and their resulting price effects.

2.3.1 LNG-related price shocks

LNG production facilities mostly have dedicated gas reserves and are not expected to trade significant quantities of gas on the market under normal operating conditions. However, there are circumstances under which the LNG sector can be expected to affect the operation of a liquid wholesale gas market.

An LNG producer may face a short term upstream supply interruption (eg, the outage of a CSG field) and consequently look to a trading market to procure the gas it requires. The LNG facility will most likely still need to meet contractual obligations to export LNG and therefore will have to source gas from other sources outside its production portfolio. The consequent increase in demand will cause the market price to rise at trading hubs on the east coast and market participants will have incentives to increase the gas they are able to supply to the wholesale market to take advantage of the elevated price.[38]

Similarly, it is conceivable that an LNG facility may unexpectedly go offline (eg, because of an unplanned outage or tropical cyclone) meaning that gas originally destined for LNG exports could be sold on a trading market. This is compounded by the difficulty that CSG fields face in 'turning down' production. The inability to substantially reduce production would cause the price on wholesale markets to fall in the short term and market participants would adjust their gas trading strategies in light of this development.[39]

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38 For example: industrial facilities and gas-fired generators may, to the extent that they are able, reduce their operations if they can instead sell gas into the wholesale market at a profit; parties with gas in storage may also release reserves to the market in order make a profit on the gas; and retailers may, depending on the time of year and their own demand for gas, sell reserves of gas at the elevated price.

39 For example: for large-scale gas consumers, such as industrial facilities, the lower gas price would lead to a reduction in the cost of production; gas-fired generation could be provided on the wholesale electricity market at lower cost due to lower fuel costs; retailers would have the opportunity to fulfil current (and potentially future) customer demand at a lower cost; and any parties with storage capabilities could take advantage of the future opportunity to arbitrage prices by building up gas reserves when the price is low.

The above analysis demonstrates that the existence of the LNG sector has the potential create substantial opportunities for trade that did not previously exist. In some respects, these opportunities have already begun to present themselves with the start-up and commissioning of three LNG trains in 2015 todate.

The examples outlined above are short run shocks and the market price for gas would be expected to return to reflecting supply and demand conditions in the domestic market once the disturbances in the LNG sector has been resolved.

2.3.2 Weather events

The price for gas is also affected by weather conditions. If colder-than-expected weather occurred in winter it would have an effect on demand for gas in a trading market and would therefore have an effect on the wholesale gas price. In this example is it assumed that the LNG sector is functioning as normal.

In this scenario, retailers of gas would face increased demand as households and smaller customers use more gas for heating and other purposes. As the weather is colder-than-expected, the retailer will have to source more gas than it had previously anticipated on the market. This increase in demand would cause wholesale gas prices to increase.

On the supply side, producers of gas could increase their production in order to supply more gas on the wholesale market in response to the increase in price. The amount that producers can increase their supply is dependent on the availability of additional production capacity and storage.

Other market participants could also provide gas for sale in order to make a profit on the volume of gas traded. Gas-fired generators will face increased input costs and may wish to reduce electricity generation and sell off any gas reserves they may have at a profit. Industrial facilities may choose to lower production and run down inventories as result of the price increase. Such facilities may also wish to sell off any gas reserves they may have at a profit. Storage facilities can also provide gas on the wholesale market in response to a weather-related price increase.

This example shows that trading market prices could fluctuate even in the absence of any shocks to the LNG sector. In this example, an unexpected weather event caused prices to increase. The liquid wholesale gas market provides an efficient price signal and market participants are able to react to changes in underlying supply and demand conditions.

The number of different participants in the market with negatively correlated demand profiles and incentives means that increased supply could be made available to be traded on the market in response to a price increase. In this way, gas that is traded on the market is allocated to the market participants that derive the most value from that supply of gas at that moment in time.

2.3.3 Wholesale electricity price signals

Other commodity markets can impact on wholesale gas prices. In this example, prices in the wholesale electricity market have increased. This could be as a result of the high penetration of intermittent renewable generation, as can be seen in South Australia.

In circumstances where the supply of renewable generation is low, and there are problems with thermal generators or interconnectors, prices in the spot market for electricity may rise to very high levels. In this scenario, gas-fired generators may need to procure gas quickly on the market to increase their supply of gas and therefore their generation output.

On the wholesale gas market, gas-fired generators' unanticipated increase in demand for gas would put upward pressure on prices. This is because the generators wish to increase the amount of electricity they supply, and therefore the amount of gas that they consume. If these generators do not have flexibility available under existing GSAs, they will need to acquire additional gas from the market.

The increase in price on the wholesale market provides other participants with an opportunity to arbitrage gas prices. Gas retailers could sell off any excess gas supplies they may have available through contracts. This effect may vary based on weather conditions. If, for example the price increase caused by high electricity prices occurred during hot weather (when electricity demand can peak), the retailer may have lower-than-expected demand for gas. This would mean that the retailer can release excess gas on to the market in order to make a profit from the elevated price.

Industrial users, who have the capacity to ramp their production levels up and down based on input costs, could reduce their production in response to the price increase. They could also sell any excess supplies of gas on the market. Similarly, gas storage facilities could sell their reserves at a profit on the market as a result of the increase in price.

As in the examples above, the supply side of the market would also have the ability to react to the price increase by supplying additional gas on the market, subject to available capacity. This example shows that, as gas is used as an input to many different industries, conditions in other markets can affect demand for gas and therefore the wholesale gas price.

Table 2.1 Major gas users on the east coast of Australia

Licenced Gas Retailers	Large Industrial Users (including LNG producers)	Gas-fired Generators
AGL	Adelaide Brighton Cement	AGL
ActewAGL	APLNG	Alinta
Alinta	BlueScope Steel	Arrow Energy
Aurora Energy	BHP Billiton	Braemar Power Project
Australia Power and Gas	Boyne Smelter	CS Energy
Covau	BP	EnergyAustralia
Dodo Power and Gas	Bradmill	Ergon Energy
EnergyAustralia	Brickworks	Delta Electricity
Lumo	GLNG	ERM Power
Origin Energy	Incitec Pivot	GDF Suez
Red Energy	MMG	Hydro Tasmania
Simply Energy	One Steel	Origin Energy
Tas Gas Retail	Orica	Pelican Point Power
	QCLNG	QGC
	Queensland Alumina	Snowy Hydro
	Qenos	Stanwell
	Rio Tinto	Synergen Power
	South Australian Water Corporation	
	Visy	

Source: K Lowe Consulting, *Gas Market Scoping Study: A report for the AEMC*, July 2013; and STTM and DWGM registration lists.

3 Achieving the Vision

Box 3.1 Summary of chapter

The key focus of Stage 2 of the review has been the identification and assessment of different approaches to wholesale gas market and pipeline framework design that aim to support the development of liquid trading of gas. In particular, the Commission has considered two models that have been successfully applied in overseas markets:

- gas commodity trading hubs located at specific physical points, supported by arrangements which also allow for the trading of pipeline capacity; and
- "virtual" trading hubs where market participants can obtain access to the totality of a given pipeline system and trade gas with any other participant flowing gas elsewhere on the system.

These two approaches each come with their own advantages and disadvantages, and their appropriateness varies according to the relevant circumstances. Liquid trading hubs have developed at physical points in North America, stimulated by the significant number of market participants there. This level of competition has also assisted with the development of trading in pipeline capacity, which has driven the efficient use of pipelines and supported the liquidity of trading in gas at the hubs.

Virtual hubs have been developed in Europe, and have successfully addressed the challenges resulting from the smaller numbers of market participants there (where market structures have typically evolved from a single monopoly provider in each member state). Virtual hubs pool all potential competitors in a given region, maximising liquidity. While virtual hubs typically require the application of a more interventionist pipeline regulatory regime and result in less precise locational investment signals, the drawbacks of this are accepted in European markets, which tend to have relatively small, meshed pipeline systems.

In order to develop a liquid trading market on the east coast of Australia, it will be necessary to address the challenges presented by a small number of market participants dispersed over a very large geographic area. Consequently, the Commission has developed a roadmap for market development that seeks to concentrate trading at two hubs and to facilitate access to these hubs.

Trading in the south would be focused on a virtual hub in Victoria, and in the north would be facilitated by the evolution of the gas supply hub at Wallumbilla. To move gas to and from the hubs will require improvements to be made to the current pipeline arrangements in order to promote trading in pipeline capacity and, consequently, the efficiency with which pipelines are used and the liquidity of trading in gas. In this way, the roadmap aims to achieve the Energy Council's Vision for gas markets and to benefit the long term interests of consumers.

3.1 Introduction

In this review, the Commission has been asked by the Energy Council to consider the:[40]

- optimal number and type of facilitated markets on the east coast, taking into account the current arrangements and changing gas market conditions; and
- issues associated with, and potential benefits of, the development of an efficient financial derivative market for gas.

The terms of reference require the Commission to draw its conclusions on these matters together to set out a roadmap for the continued development of the market. This chapter sets out the high-level considerations and trade-offs that the Commission has had regard to in developing the roadmap and its specific recommendations (which are detailed in the following chapters). The recommendations are made in the context of achieving the NGO and the Energy Council's Vision for Australia's future gas market.

A key outcome of the Vision is the establishment of an *efficient* and *transparent* reference price for gas. An efficient reference price requires a liquid market with many parties buying and selling gas, which necessarily implies that trade be focused at a point that best serves the needs of participants - another aspect of the Vision.

A liquid gas market provides participants with confidence that prices are meaningful and reflect traders' expectations of the supply and demand balance. In a liquid market there are many buyers and sellers of gas, which reduces the likelihood that any single buy or sell order is likely to move the price substantially. Liquid markets also support the ability to trade large volumes in a short period of time and are resilient to supply/demand shocks.

Growth in trading liquidity requires the creation of a self-reinforcing cycle that encourages both the demand and the supply side of the market to participate. More participants and greater traded volumes lead to more meaningful pricing signals, giving sellers confidence that they will have a market for their supply. Increased supply gives buyers the confidence to augment their bilateral contracts with traded gas from the market. As trading volumes increase, financial risk management tools will be developed by industry, reducing the cost of managing price risk and encouraging even more participation in the physical market.

Achieving the Energy Council's Vision of a liquid wholesale gas market will lead to lower barriers to entry, promote competition and increase efficiency. Liquid trading markets promote the efficient allocation of gas and act as a credible alternative source of supply to bilateral contracts, contributing to competitive tension in bilateral contract negotiations. Liquid and transparent markets are also fundamental to consumers being

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40 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, pp. 2-3.

able to know whether the price of gas reflects underlying demand and supply conditions.

However, and as recognised by the Vision, to develop liquid trading requires participants to be able to readily move gas between trading locations. This is especially important in an environment such as the east coast of Australia with few, geographically dispersed producers and users. If there are obstacles to participants being able to access transportation capacity, this will inhibit their ability to move gas to market and trade it, diminishing liquidity.

Outside of Victoria, pipeline capacity has generally been sold under bilateral contracts and on a basis that matches long term gas supply agreements. Participants would typically sign a gas supply agreement to ship gas from a production facility to where the gas would be consumed and concurrently purchase pipeline capacity and any hub services required to deliver the gas.

While this system of bilateral contracting, referred to as "contract carriage", has supported substantial investment in pipelines, it is not clear that the current arrangements allow for capacity rights to be easily traded between users. The inability to reallocate pipeline capacity rights to those that value their use most highly is likely to represent a major barrier to the development of liquid trading markets with prices that can respond to short term shifts in supply and demand. If traders are purchasing gas to supplement their bilateral contracts on a day-ahead, week-ahead and/or month-ahead basis, then matching pipeline and hub services needs to be available at a competitive price to support trading liquidity.

Non-discriminatory access to pipeline capacity and hub services is critical for the development of trading liquidity, as it allows all participants to compete at the hub on a level playing field. This means that all participants must be able to access services to transport gas to and from hub locations, as well as within hub locations, on the same basis. If this precondition is not met, this will inhibit competition and participants' ability to respond to price signals.[41]

In the Victorian DWGM, pipeline capacity within the virtual hub is implicitly allocated as an outcome of the bidding process under a market carriage framework. This allows participants to trade gas without having to procure pipeline services in advance, although the lack of firm capacity rights in the Victorian system of "market carriage" has led to concerns with the efficiency of investment outcomes over the long term.

Consequently, in formulating a roadmap for market development, the Commission has investigated the interactions between gas commodity trading and pipeline arrangements and the trade-offs that must be considered.

41 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 10, 31.

3.2 Wholesale gas market and pipeline framework design options

Gas trading markets operate at hubs, which are defined locations on a pipeline system where the transfer of ownership and pricing of gas takes place. Much of the Commission's work over Stage 2 of the review has been to identify and assess different approaches to wholesale gas market and pipeline framework design that aim to support the development of liquid trading in gas. In particular, we have considered two models that have been successfully applied in overseas markets:

- gas commodity trading hubs located at specific physical points, supported by arrangements which allow for gas to be readily transported between these points by also trading pipeline capacity; and
- "virtual" trading hubs where market participants can obtain access to the totality of a given pipeline system covered by the hub and trade gas with any other participant flowing gas elsewhere on the system.

3.2.1 Physical hubs supported by pipeline capacity trading

A physical hub is a specific geographical point in the gas pipeline network where gas delivered to and transferred from that location is priced and traded.[42]

In order to trade gas at a physical hub, shippers must physically transport gas to and from the location. Shippers therefore require transportation rights from points of production, between hubs, and to demand points. These rights can be bestowed to shippers through contracts with pipeline owners (known as Gas Transportation Agreements (GTAs)), as in the Australian system of contract carriage. However, the efficiency of the gas commodity trading at the hub will depend on the extent to which capacity rights are available (or can be reallocated) to market participants wishing to trade.

Physical hubs provide signals on the price of gas at specific locations on the system, while the price difference between two hub locations can provide signals for investment in pipeline capacity. The STTM hubs in Adelaide, Brisbane and Sydney and the GSH at Wallumbilla can be broadly characterised as physical hubs.

3.2.2 Virtual hubs

In contrast to a physical hub, a virtual hub pools trading at a notional point that extends across all, or part of, a pipeline system. Virtual hubs allow for title transfer of gas anywhere within the definition of the hub, with a single price for all trades of gas within the area regardless of the particular location within the hub, obviating the need to purchase point to point pipeline capacity.[43]

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42 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 33.

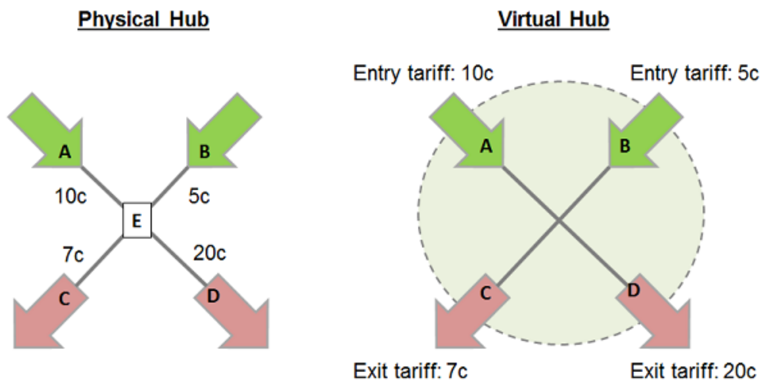
43 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 45.

Within a virtual hub, a hub operator manages flows within and between the pipelines forming the network. The hub operator's management of flows between pipelines or different parts of the network within the hub is automatically provided so, unlike under contract carriage, market participants are not required to contract transportation capacity *within* the hub.[44,45] Instead, participants simply ship gas to one of the entry points and withdraw gas from any of the exit points on the system.

Figure 3.1 explains the concept of virtual hubs, by showing a physical hub on the left and a virtual hub on the right. Participants at the physical hub pay to use specific pipelines to transport gas to hub E where it is traded. At the virtual hub, participants pay to enter or exit the virtual hub but do not need to book capacity along the pipeline route. Gas is traded notionally anywhere within the virtual point, not at a specific location such as point E in the physical hub. This notional trading supports the concentration of liquidity as buyers and sellers are pooled across the hub and can trade gas irrespective of where it actually is in the physical system.

Where there is no discriminatory access to pipeline capacity and capacity rights can be readily defined and easily tradeable, trading at physical and virtual hubs is similar. This is shown in Figure 3.1 where the cost of shipping gas between any of the points is the same for both hub designs.

Figure 3.1 Physical and Virtual Hubs



- Participants pay the amounts shown to use specific pipelines
- For example, to flow gas from A to C would cost 17c
- Gas is traded at point E on a voluntary bilateral basis

- Participants pay to enter and/or exit the virtual hub but do not need to book capacity along route within it
- For example, to enter at A and exit at C would cost 17c
- Gas can be traded anywhere in the hub on a voluntary and bilateral basis too

Source: AEMC derived from: FTI, *East Coast and DWGM Gas Reviews*, Presentation to Public Forum, 30 September 2015, available at: http://www.aemc.gov.au/getattachment/2ada4f65-b34e-486d-8055-3148e6245d14/Public-Forum-Slides.aspx

44 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 46.

45 The arrangements applying to the DTS in Victoria have come to be known as a "market carriage" system, as access to pipeline capacity is primarily determined by outcomes in the Declared Wholesale Gas Market. However, in international terms, market carriage is an unusual form of virtual hub.

3.2.3 Trade-offs between physical and virtual hubs

These two approaches to hub design set out above each come with their own advantages and disadvantages, with the result that their appropriateness can vary according to the relevant circumstances.

Assessment of physical hubs

Physical hubs for the trading of gas can develop in response to market demand for them, and require less regulatory intervention and oversight to establish and operate as compared to virtual hubs. Combined with effective pipeline access arrangements, the market-led price discovery process at the specific hub locations can provide signals for:

- efficient *provision of, and investment in* pipelines between locations; and
- efficient *allocation* of transport services and natural gas where it is most valued.[46]

However, for these benefits to emerge, the price discovery process at the physical hub need to be reliable, which in turn requires liquidity in the market at the hub. There are a number of prerequisite circumstances for liquidity to emerge:

- physical hubs require a large number of market participants being able to trade at the specific hub locations;[47] and
- market participants require flexible, low cost and non-discriminatory access to pipeline capacity to get to and from hubs, and providing this can require sufficient competition in primary and secondary markets for pipeline capacity to exist. Without this access, the ability for market participants to trade at the physical hubs is reduced.[48]

Consequently, a certain level of regulatory intervention and supervision may be necessary to stimulate the development by industry of effective arrangements for pipeline access (that is, to improve the ability and incentive of shippers and pipeline owners to allocate capacity to the party that values it the highest). However, even with these initiatives, in highly meshed networks it may be challenging to facilitate efficient trading of capacity between shippers. Under such circumstances, the cost and complexity of a market-driven approach to appropriately allocate and reallocate capacity rights between shippers may be prohibitively high.

46 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 40-41.

47 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 41-43.

48 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 40.

Assessment of virtual hubs

Virtual hubs have benefits in circumstances when physical hubs have drawbacks:[49]

- virtual hubs facilitate trading by allowing market participants to trade anywhere within the hub without having to book pipeline capacity to transport the gas between particular points. This reduces transaction costs and is a particular advantage on networks where there may be several nodes at which capacity bookings may otherwise be required;
- by virtue of a larger footprint, virtual hubs pool a larger number of market participants, enhancing liquidity; and
- problems of inflexible, high cost or discriminatory access to pipeline capacity are addressed *within* a virtual hub because access to the notional trading point is automatically provided to market participants, further enhancing liquidity once their gas is inside the hub. Virtual hubs are therefore particularly useful where networks are highly meshed, or where pipeline access is otherwise problematic. Nevertheless, market participants still need adequate access to, from and between virtual hubs.

By promoting liquidity, virtual hubs serve to promote competition in the wholesale gas market and, by improving the reliability of price signals, promote the efficient allocation of gas where it is most valued.

However, the main drawbacks of a virtual hub compared to a physical hub are that, because of the lack of locational signals:

- there is a need to manage gas flows *within* the hub, which can result in higher costs that may largely have to be smeared across hub users or in the amount of long term capacity rights being reduced;[50]
- investment signals will be weaker and less precise than under contract carriage. Although investment signals can be given at entry and exit points into and out of the system, decisions to invest to reinforce specific flow paths *within* the hub will be made by the pipeline owner in response to the signals given by the purchase of entry and exit capacity.[51]

Furthermore, virtual hubs require a greater degree of regulatory intervention to establish and operate, for example in defining the hub's size and location and setting tariffs for pipeline access.[52] While the economic regulation of capacity within virtual hubs can ameliorate any market power concerns around the accessing pipeline capacity on a non-discriminatory basis, the usual result is that it effectively

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49 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 54.

50 For a more detailed explanation, see FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 57-58.

51 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 56.

52 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 57-58.

"entrenches" the monopoly provision of pipeline capacity by the incumbent pipeline owner - to try to facilitate competition in capacity expansions can further increase the level of regulatory complexity.

Overall therefore, the approach to designing virtual hubs is one of trading off the benefits of a greater geographical footprint to have higher liquidity within the hub with that of the increased risk of congestion and weakened locational signals within the hub. It is important to emphasize, however, that the optimal amount of congestion within a virtual hub is unlikely to be zero – the benefits to customers of greater liquidity may mean that some congestion on some occasions is a price worth paying.

Conversely, where physical hubs exist, locational signals at specific network locations will be strong provided there is a sufficiently robust reference price. This can be negatively impacted if trades are spread across multiple physical hubs in a concentrated market, or if the ability to source pipeline capacity to ship gas to and from hub locations is affected by high transaction costs or limited competition for pipeline services. These key trade-offs between physical and virtual hubs are set out in Table 3.1

Table 3.1 Comparison of physical and virtual hubs

Physical hubs		Virtual hubs	
Pros	**Cons**	**Pros**	**Cons**
Trading locations determined by market demand	Dependent on a large numbers of market participants being able to trade at each specific hub	Flexibility to trade anywhere on a pipeline system without having to book point-to-point capacity	Requires management of flows within hub which can lead to increase in (smeared) costs and/or reductions in capacity
Locational prices provide strong signals for pipeline investment, which is driven by private entities	Competition in primary and secondary markets for pipeline capacity and hub services important to allow ready access to hubs	Liquidity is enhanced through pooling a larger number of buyers and sellers	Although investment signals given at entry/exit points, limited locational investment signals within hub
Lower level of regulatory oversight	Facilitating pipeline capacity trading particularly challenging when network is complex	Promote efficient use of pipeline system as capacity more easily resold	Regulatory complexity, usually including ex ante incentive regime/economic regulation

Source: AEMC analysis based on FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015.

Experience in overseas markets

As can be seen from the discussion above, whether to opt for an approach based around physical hubs or virtual hubs depends on the circumstances of the broader market environment. This can be illustrated by the differing experiences in the United States (US) and European Union (EU).

The US has approximately 200 physical hubs, connected by an extensive network of pipelines.[53] This use of an approach based around physical hubs is in keeping with the circumstances found in the US:

- there is a large number of market participants and pipeline owners, facilitating liquidity at the physical hubs and assisting with the development of trading in pipeline capacity to support the commodity trading;[54] and
- the network topology is primarily defined by long, point-to-point pipelines,[55] meaning there is relatively low complexity in gaining access to hubs via the bilateral contracting of pipeline capacity (further facilitated by regulations aimed to improve pipeline access). In such circumstances, the less precise investment signals and lack of competition in the provision of pipeline capacity under virtual hubs could result in significant costs.

In contrast, the EU has developed a system where each member state has one (or occasionally more) virtual hub(s) superimposed on top of its pipeline system. Again, this approach aligns with local circumstances, where there are:

- relatively fewer market participants and pipeline owners (as market structures have typically evolved from a single monopoly provider in each member state), meaning that virtual hubs serve to pool all potential competitors in a given region, maximising liquidity; and
- often relatively small, highly meshed transmission networks, meaning that gaining access to a specific point of the network might otherwise be complex and costly without a virtual hub.[56] The associated drawbacks of less precise locational investment signals and a lack of competition in the provision of pipeline capacity are less costly in European markets than they would be over a more geographically dispersed area.

Conceptual framework

The assessment of the differing approaches to hub design, combined with our observations of practical experience in overseas markets, suggests that physical hubs:

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53 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 33.

54 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 42-43.

55 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 42.

56 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 45.

- can generate sufficient liquidity in trading if point-to-point capacity rights are easily defined and readily available/tradeable; and
- are better at providing precise investment signals and capturing the potential benefits resulting from the competitive provision of pipeline capacity.

In contrast, the benefits of facilitating a liquid wholesale gas market through virtual hubs are likely to be greater than the associated costs when:

- the current and likely future number of market participants is relatively low, such that liquidity in trading gas is unlikely to develop at physical hubs and a competitive market in pipeline capacity does not emerge to support this; and/or
- the technical characteristics of the pipeline system may mean that frictionless capacity trading and hub services arrangements cannot be practically achieved. In a meshed network with many potential combinations of entry and exit points, it may be more efficient for a hub operator to manage flows and balance the system on behalf of participants.

However, these considerations are unlikely to be black and white – they will require trade-offs and judgements to be made.

3.3 Applicability of physical and virtual hubs in Eastern Australia

Some parallels can be drawn between the broader market environment in Eastern Australia and the markets discussed in the previous section. However, the east coast market arguably suffers from the challenges arising in both the US and Europe.

Like the US, the transmission network is primarily made up of long, point-to-point pipelines, typically between production centres and far distant demand centres. Consequently, the efficiency of investment is a key concern. However, like many markets in the EU, there are a relatively low number of market participants (although lower barriers may stimulate additional competition). As a result, the ability of virtual hubs to pool liquidity may be of significant benefit.

This means that there is not an obvious international precedent to draw on, and that an approach that draws on both models should also be considered.[57]

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57 To some extent, this hybrid approach is also observed in the EU. Although the EU gas market primarily consists of a system of regulated virtual hubs, some merchant pipelines not subject to economic regulation link the hubs. One such example, Interconnector UK, was discussed in: AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Pipeline Regulation and Capacity Trading Discussion Paper, 18 September 2015, Appendix B.

Box 3.2 The Wholesale Gas Markets Discussion Paper

On 6 August 2015, the Commission published the Wholesale Gas Markets Discussion Paper to progress the debate on the future development of wholesale gas trading markets on the east coast of Australia.[58] Three high level market design concepts, ranging from multiple physical hubs to two large virtual hubs, were developed as a way of seeking targeted feedback from stakeholders:

- **Concept 1** - Multiple physical hub locations at major pipeline junctions and production centres across the east coast, with simplified balancing mechanisms in the major capital cities.
- **Concept 2** - A new virtual hub in the north covering the Roma to Brisbane Pipeline and current Wallumbilla GSH (the "Northern Hub") and a virtual hub in the south covering the Victorian Declared Transmission System (the "Southern Hub"), with balancing mechanisms at Adelaide and Sydney. Shippers would have to bilaterally contract with pipelines to move gas between these hubs.
- **Concept 3** - One large virtual hub in the north (ie north-west of Moomba) and another in the south that, together, cover the entire east coast.

The Commission received 17 public submissions to the discussion paper, which are published on the AEMC website and summarised at Appendix C. Through submissions, stakeholders drew out the trade-offs between the concepts, such as Concept 1 being most likely to promote efficient investment while Concept 3 would be most likely to promote liquid trading. A key theme from submissions was that wholesale market design decisions and pipeline capacity trading arrangements are interlinked and cannot be thought of separately.

One example of such a hybrid approach was presented in the Wholesale Gas Markets Discussion Paper as Concept 2, and reflected a view that there may be some advantages in the broader application of virtual hubs on the east coast outside of Victoria. The rationale for selecting the Roma to Brisbane Pipeline (RBP) to be used as the basis for a virtual hub in the north provides a good illustration of the criteria that should be considered in determining whether or not a virtual hub is appropriate:

- A relatively **large number of diverse market participants** (or potential participants) are connected to the RBP. There are significant conventional and unconventional production sources, some large industrial users in Brisbane, retailers servicing distribution-connected users in Brisbane, a number of gas-fired generators and numerous interconnections to pipelines flowing to the LNG export facilities. There would therefore be substantial benefits from pooling the trading activities of all these parties at one virtual hub, not just due to their

58 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Wholesale Gas Markets Discussion Paper, 6 August 2015.

absolute numbers but also because their differing demand and production profiles would be complementary and likely to result in trading opportunities.

- The RBP represents a **technically complex system**, with multiple injection and withdrawal points.[59] This means that trading pipeline capacity is particularly difficult. There would likely be significant benefits of establishing arrangements where shippers were contractually able to flow gas to any other point on the pipeline by procuring a single entry or exit right.
- The footprint of the pipeline system **covers a relatively small geographic area**.[60] Therefore the limited nature of the investment signals given by the sales of entry and exit rights into and out of a virtual hub are less of an issue than for larger systems where any costs associated with inefficient investment could be much greater.
- Finally, the **costs of regulation are relatively low**, as compared to the counter-factual of the status quo. The RBP is already subject to economic regulation through the coverage regime, with the rationale for this arguably reflecting a low likelihood that a competing pipeline will be developed. While the regulatory arrangements applying under a virtual hub would likely be more complex than the current coverage regime, the incremental costs would be lower than for an uncovered pipeline. Equally, the effect of entrenching the monopoly status of the pipeline provider can be considered less costly if competitive entry is unlikely in any event.

In circumstances where the above criteria are relevant, the Commission considers that the application of virtual hubs may represent an appropriate long term model.

Although the establishment a virtual hub would be likely to present complex transitional issues and come with material implementation costs,[61] the Commission is of the view that the development of arrangements for a virtual trading hub model in the Australian context would represent an important part of the regulatory "tool-kit" to support the future development of the market. In particular, if more incremental reforms are unsuccessful in generating a liquid northern trading hub, the Commission considers that it may then be appropriate to introduce a virtual hub in south-east and/or south-west Queensland.

3.4 The Commission's recommended roadmap for market development

The east coast currently has three gas market trading designs, each developed separately of the other and at different times in the evolution of the broader east coast

59 We understand that there are approximately 25 injection and withdrawal points.

60 The mainline of the RBP is 438km long. For comparison, the Moomba to Sydney Pipeline is 2,029km long. Information sourced from AEMC Gas Scheme Register, see www.aemc.gov.au.

61 Given the nature of the current arrangements, establishing a virtual trading hub supported by entry/exit capacity arrangements is likely to be less difficult on the Victorian DTS as compared to pipelines currently operating under contract carriage.

market. These are spread over five trading hub locations (possibly six in the near future, if an additional GSH is established at Moomba).

The Commission considers that at the core of any roadmap for the future development of the market should be the concept that trading should be conducted in as few locations as possible so as to concentrate what limited liquidity exists on the east coast. However, unlike European countries, the geography of, and range of conditions applying across, the east coast of Australia mean that it may not be possible to concentrate trading in one location or for a single reference price to be meaningful.

Consequently, the Commission considers that two reference prices - and so two trading hubs - are likely to best strike a balance between the benefits of concentrating trading and having prices that are meaningful. These two prices would seek to reflect market conditions in the two regions which have both significant sources of supply and demand:

- In Queensland, demand is primarily driven by LNG production and large users (including gas-fired generation) and there is significant conventional and unconventional gas production.
- In Victoria, gas is primarily consumed by residential customers, and so is driven by day-to-day weather and the seasons. There is also significant production from the Bass Strait, with the Gippsland Basin in particular emerging as the "swing" producer of gas for most domestic demand.

Although there could well be reasons for wanting to establish trading hubs to reflect market conditions in other areas, the Commission would have concerns with approaches that sought to establish more than two reference prices emerging as this may serve to unnecessarily split liquidity both in short term trading and in the benefits that can be obtained from having an accepted market price to refer to in financial derivatives and in long term physical contracts.

3.4.1 Improvements to the pipeline capacity frameworks

While the Commission seeks to concentrate trading as much as possible at two hubs, the Commission does not consider that two very large virtual hubs covering most or all of the pipeline system would be likely to be efficient.

Over the majority of the east coast of Australia, the geographically distant nature of production and demand centres, with long, point-to-point pipelines, means that there would be significant costs associated with virtual hubs in terms of less precise investment signals and reduced competition to provide additional pipeline capacity. Efficient investment outcomes form a very important part of the NGO, when assessing long term benefits to consumers. Consequently, under the Commission's recommended roadmap, the majority of pipelines would continue to operate a contract carriage regime, similar to that which currently exists.

Nevertheless, the Commission considers that the current contract carriage model of pipeline access can be improved so that market participants are able to obtain more flexible, lower cost and non-discriminatory access to pipeline capacity between hubs. Improving the contract carriage model is the topic of **Chapter 4** of this report, in which the Commission recommends:

- the introduction of an auction for contracted but un-nominated capacity - which is currently sold as "as-available" capacity - with a regulated reserve price on all pipelines;
- the mandatory creation of capacity trading platforms, to lower the transaction costs associated with trading capacity and through which information regarding all trades would be published. Capacity products would be standardised to facilitate trading through the platform; and
- publication of the actual (as opposed to the advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price.

As discussed in Chapter 4, improvements in pipeline access should improve the liquidity of trading at hubs, the reliability of hub prices, and in turn provide better signals for pipeline investment, and gas consumption and production – and hence promote the NGO. In particular, these recommendations seek to promote much shorter-term trades in pipeline capacity trading, which should support the ability of markets to generate prices that better reflect short term shifts in supply and demand.

These reforms should be implemented as soon as practicable, to expedite the expected benefits.

3.4.2 Enhancing the existing DTS arrangements to develop a Southern hub

The Commission considers that the existing arrangements for the DTS in Victoria provide an opportunity to develop a more effective virtual trading hub, that could then provide a reference price reflecting market conditions in southern Australia.

The current DWGM market design is a form of virtual hub. However, the Commission recommends that this be further developed to:

- provide additional trading options for market participants, through a 'voluntary trading with market-based balancing' approach. This would include the introduction of a trading exchange similar to that in operation at Wallumbilla, providing a low cost, anonymous and transparent way for participants to trade. The exchange operator would report prices that could be used as a reference for financial derivative products. Participants would also be able to trade bilaterally at the hub, with the existing approach to balancing continuing to play a residual role to guarantee security of supply to consumers and provide certainty to traders; and
- introduce a system of entry and exit capacity rights to replace the existing system of limited transportation rights in the market carriage arrangements. An entry-exit model would retain the general benefit of a virtual hub by pooling

liquidity, but would provide improved investment signals as compared to the current arrangements.

An overview of 'voluntary trading with market-based balancing' is set out in Box 3.3.

Box 3.3 Overview of voluntary trading with market-based balancing

The key features of a system of 'voluntary trading with market-based balancing' are:

- participants would be incentivised to balance their own injections to and withdrawals from the DTS over a certain period (known as the 'balancing period') and would be able to continue to trade with one another to do so; and
- in the event that participants were not collectively balancing their injections and withdrawals sufficiently, the hub operator would take actions to maintain the network within safe operational limits (a process known as 'residual balancing') and pass the costs of these actions through to the parties that were out of balance.

Importantly, participants would not be forced, as in the current DWGM arrangements, to submit bid and offer price-quantity pairs for all gas injections and withdrawals, and a reverse auction style process would not be run to determine the market price.

Instead, participants would buy or sell gas through an exchange or trade bilaterally outside the exchange. When a trade occurs, the hub operator would be notified, so that the existing physical nominations of the buyer and seller could be adjusted at the hub.

Exchange-based trading would occur between predefined business hours on standardised, hub specific contracts. This would provide participants with greater flexibility in how they buy and sell gas than the current reverse auction mechanism and some common contracts would include: on-the-day; day-ahead contracts; week-ahead; and month-ahead. Exchange-based trading is also less administratively complex to implement, as complex pricing algorithms are not required to determine the market price.

Participants would generally utilise a combination of exchange-based products, along with their bilateral contracts, in order to manage their gas portfolio needs. Continuous exchange trading facilitates the integration between the spot and forward markets through continues trading of the forward products leading up to the gas day.

A liquid forward curve would provide participants with transparency around the market's future price expectations for gas, say, a week ahead or a month ahead or even the following year. Financial derivatives to manage price risk are often developed over the most liquid of these physical products.

The rationale for, and design of, an entry-exit model to support this type of trading and suitable for the DTS is discussed in **Chapter 5** and in more detail in the Draft Report for the DWGM Review.[62]

The Commission does not consider that the contract carriage model, even with the improvements discussed above, is likely to be appropriate for the DTS. The DTS is complex and relatively highly meshed, and hence defining and facilitating the trade of pipeline capacity rights would be very difficult. These limitations in efficiently allocating pipeline capacity mean that trading liquidity at a physical hub would be unlikely to emerge, and hence the benefits of the market outcomes set out in the Vision would be unlikely to materialise.

Instead, the Commission considers that the DTS meets the criteria set out in section 3.3 for the application of a virtual hub market design, and that this would better promote the achievement of the NGO. Uniquely, in Victoria the introduction of an entry-exit model would represent a less significant step and therefore the benefits of such a virtual hub could be realised with lower (although still material) implementation costs.

As with the improvements to pipeline capacity trading, the transition of the existing virtual hub model on the DTS to an entry-exit system should be effected as soon as practicable.

3.4.3 Evolutionary development at Wallumbilla to provide a Northern hub

In the same way that developing the DWGM appears a logical approach to providing an effective southern trading hub, the Commission considers that the ongoing market development program at Wallumbilla represents the best means of providing a northern pricing point.

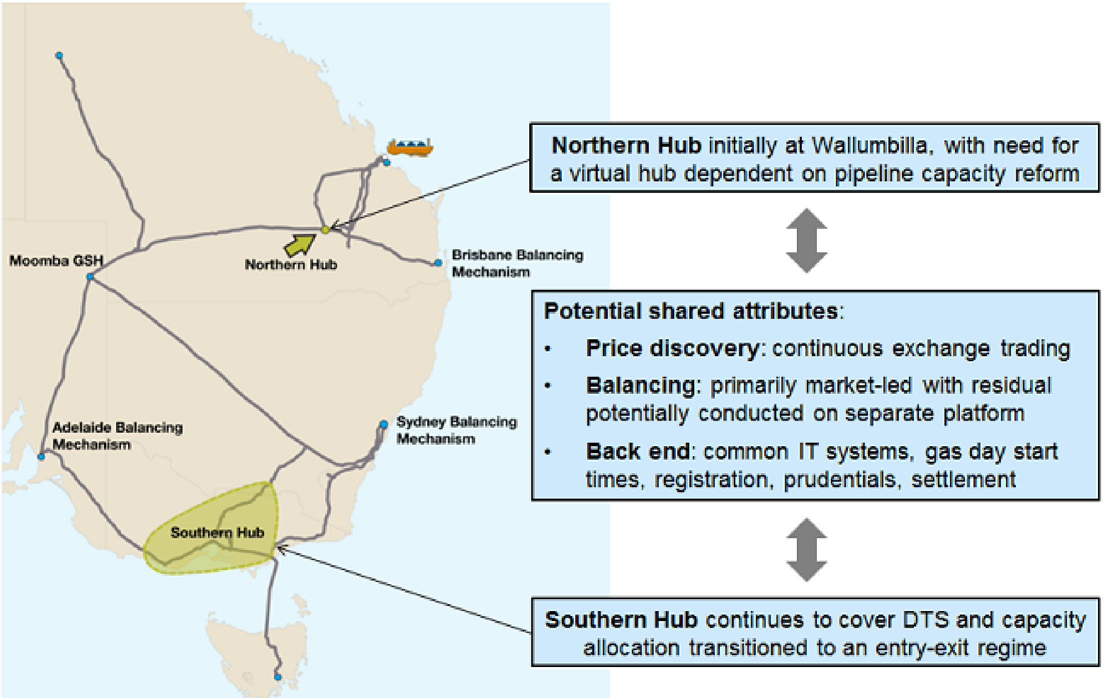
Wholesale commodity trading is already undertaken at Wallumbilla through the GSH arrangements, which were introduced in March 2014. Liquid trading is most likely to develop where there is a diversity of producers and users, and potentially other services that facilitate trading (such as storage). The Commission considers that Wallumbilla, which is located at the intersection of numerous pipelines connecting a range of producers, users and other facilities (including storage), represents the most appropriate location around which to base a northern trading hub.

Trading at Wallumbilla has been hampered to date by physical constraints within the infrastructure there, which means that gas cannot always flow completely freely, and which has required that trade be split across three points. AEMO has been undertaking a work program to progress this issue and is recommending that the Energy Council approves the introduction of "Optional Hub Services" arrangements. These aim to promote and facilitate the trading of hub services (primarily compression) to allow participants to access a single pricing point at Wallumbilla, in a similar manner to the Commission recommendations regarding the trading of pipeline capacity.

62 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2015.

Although such a Northern trading market would initially be a physical hub, the Commission considers that there would be opportunities to harmonise the trading arrangements (for instance, the exchange) across the two markets. This can be expected to increase efficiency through a reduction in complexity and regulatory burden. Furthermore, if the recommended initiatives to facilitate the trading of hub services and pipeline capacity proved ineffective at promoting gas market liquidity, the Commission considers that there would be a case for expanding the hub either over the Wallumbilla compound or more widely over pipelines in south-east and/or south-west Queensland.

Figure 3.2 Trading will be concentrated at two hubs



The Commission's recommended approach to the evolutionary development of the Wallumbilla GSH is discussed in **Chapter 5**. The chapter also sets out how the potential introduction of a GSH at Moomba might play an important role in the transition to a more developed and liquid market.

The chapter finally discusses the role that should be played by the existing STTM hubs once more liquid trading has developed at the Southern and Northern hubs. The STTM hubs, located in capital cities remote from producers or users with diverse demand profiles, are unlikely to represent appropriate locations to develop liquid trading markets. Consequently, the Commission envisages that, over the long term, these markets will transition into more simple balancing mechanisms primarily used to support retail competition.

3.4.4 Information to support the market

The Commission's recommended approach to the evolution of gas trading hubs on the east coast is supported by a detailed package of recommendations to enhance the information provided to the market.

An important characteristic of a workably competitive market is that participants have ready access to the information they require to make informed decisions about the prices they expect to see resulting from the market. In gas markets, such pricing expectations are not formed in relation to one specific data point but require a range of information about production and consumption levels, transportation flows, and investment levels in both the short and long run.

A central repository of information for use by all market participants and the public exists in the form of the Natural Gas Services Bulletin Board. However, the Commission has identified that there are some gaps and asymmetries in information provision that may be affecting the efficiency with which gas and other resources are allocated in the market and across the economy. The Commission has therefore developed a package of draft recommendations to improve information transparency through developments to the Bulletin Board.

To address the informational gaps and asymmetries, the Commission's draft recommendations include making improvements to the Bulletin Board and its governance in the following areas:

- broadening the stated purpose of the Bulletin Board;
- expanding the coverage of the Bulletin Board to include additional information;
- increasing the frequency with which certain information should be updated;
- improving the reporting framework, to allow all relevant facilities to report;
- strengthening the compliance framework;
- amending the governance of the Bulletin Board's funding arrangements; and
- introducing a regular review process to maintain the relevance of the Bulletin Board and the information reported on it.

Further information is provided in **Chapter 6** and, in recognition of the detailed nature of the recommendations, in a comprehensive report separate to this document. The supplementary report also sets out the changes that would need to be made to the NGL, NGR, National Gas Regulations and Bulletin Board Procedures to effect the recommendations, and the process for doing so.

3.4.5 Implementation

The Commission’s recommendations for the East Coast and DWGM reviews, summarised above and detailed in the following chapters, form a package of integrated reforms. Once in place, these reforms 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.

Collectively, these recommendations form a roadmap for the continued development of the east coast gas market. As such, the Commission is developing a detailed plan for the implementation of the recommendations.

While the Commission considers that it is likely to be desirable for many of its draft recommendations to be progressed as quickly as possible, there are also dependencies involved for some elements of the package. In particular, the further evolution of the Northern Hub at Wallumbilla is likely to be guided by the extent to which effective trading of pipeline capacity and hub services develops.

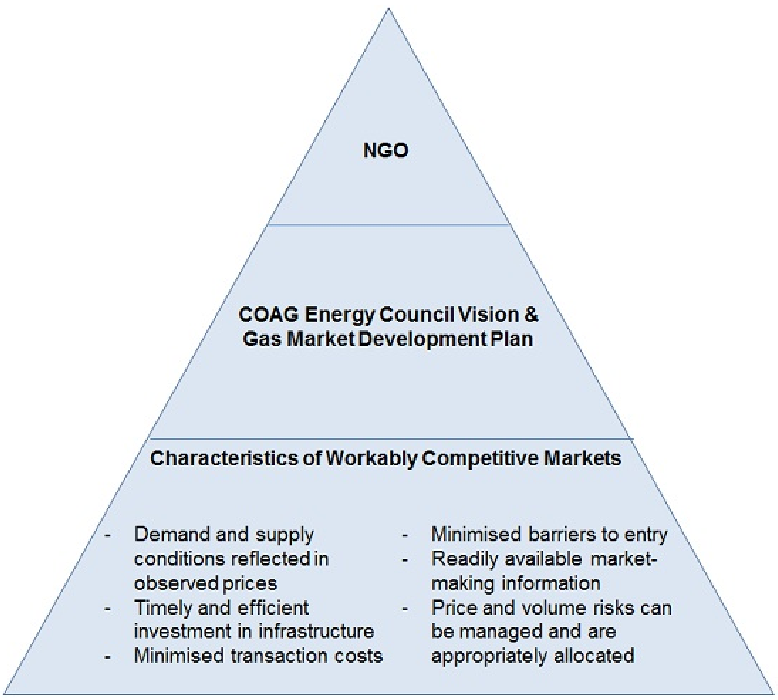
These considerations in phasing the implementation of the overall package are discussed in **Chapter 7**.

3.5 Recommendations meet the assessment framework

As discussed in Chapter 1, the Energy Council's Vision provides the Commission with a high level policy statement to guide its analysis through the review. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the NGO. Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets.

The assessment framework is set out in full in Appendix B, while the relationship between the three aspects of the assessment framework is illustrated in Figure 3.3.

Figure 3.3 Assessment framework



The NGO is structured to encourage gas market development in a way that supports the:

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 (commonly referred to as allocative efficiency);

2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs (commonly referred to as productive efficiency); 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 (commonly referred to as dynamic efficiency).

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.

3.5.1 Recommendations are assessed as a interlinked package

The market development package developed by the Commission is a set of inter-related recommendations relating to **wholesale gas trading markets**, **pipeline access** and **information** that mutually reinforce the objectives of each another.

Wholesale gas trading markets

The Commission considers that the Energy Council's Vision is best met by focussing trade at two points - in the north by continuing to evolve the existing Wallumbilla GSH and in the south at a virtual hub covering the Victorian DTS. Price discovery at both markets would occur via exchange-based trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible.

The Commission considers that this market framework would promote the NGO by supporting efficient consumption and production decisions through establishment of a meaningful reference price at each hub, which would also provide longer term signals for efficient investment in production capability, pipeline infrastructure and services supporting trading at the hub. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the STTMs can be simplified to a balancing role, which is expected to promote productive efficiency through lower transaction costs, while preserving trading flexibility.

Relative to the status quo, this model will pool trading liquidity at two geographically defined locations on the east coast to produce a reference price for gas. It will reduce transaction costs and complexity by reducing the number of market designs on the east coast, lower barriers to entry and support greater market participation by physical and financial players. By getting the characteristics of the physical trading markets right, this will provide a basis for the development of financial risk management products by industry, if required.

Pipeline access

The establishment of a meaningful reference price for gas to support efficient consumption and production decisions depends on ready access to competitively priced pipeline capacity. Absent of this, liquidity at the hubs will be restricted, impacting the reliability of the price signals provided by the trading markets.

The Commission considers that its recommendations will collectively improve access to competitively priced pipeline capacity and reduce transaction costs. Auctions for contracted but un-nominated capacity will provide non-discriminatory access and improve shipper's incentives to sell capacity to the party that values it most highly. Fostering the development of a liquid capacity trading market is particularly important for supporting market-based trading of gas and in signalling the value of short term pipeline capacity to the market.

The Commission notes that this form of capacity release mechanism is not expected to undermine incentives for investment in pipelines due to the very short term nature of the capacity products being offered for sale.

Capacity trading platforms with standardised capacity products will reduce transaction costs and increase capacity trading liquidity. The requirement for information on capacity trades to be published – including the price – lowers transaction costs and provides shippers with confidence that access is being provided on a non-discriminatory basis, reducing barriers to entry.

The Commission considers the recommendations to be a balanced and proportionate as they facilitate a market led response to capacity trading.

Information

The wholesale gas and pipeline market developments should be underpinned by arrangements to allow participants ready access to the information they require to make informed decisions. The Commission is recommending improvements to the information provision framework to expand the coverage of the Bulletin Board and improve and strengthen the reporting framework.

Enhancements to the scope, accuracy and timeliness of information are expected to promote allocative efficiency by allowing trading decisions to be based on more complete, accurate and timely information. Better decision making and greater participation on trading markets is likely to lead to more meaningful and robust market prices, which should in turn provide participants with transparent signals for investment in gas infrastructure, promoting dynamic efficiency.

4 Pipeline capacity markets

Box 4.1 Summary of recommendations

The Commission recommends a suite of three reforms with regard to pipeline capacity markets, comprising:

1. Introduction of an auction for contracted but un-nominated capacity (typically referred to as "as-available" capacity) with a regulated reserve price on all pipelines;

2. Mandatory creation of capacity trading platforms, through which information regarding all capacity trades, including prices, must be published. Capacity product standardisation would facilitate trading through the platform; and

3. Publication of the actual (not advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price.

Although the Commission does not recommend the immediate introduction of a long term use-it-or-lose-it (UIOLI) mechanism, it recommends that its introduction should be re-considered should the other recommendations above result in insufficient levels of secondary capacity trading.

The Commission is not at this stage recommending changes to the economic regulation of pipelines. The Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In light of the ACCC's findings, the Commission may supplement its draft recommendations with those concerning the economic regulation of pipelines.

The recommendations the Commission is making could be implemented by making it a requirement under the NGL that parties register with AEMO in order to undertake shipper or pipeline owner activities, and that various obligations would then be placed on registered parties under the NGL and NGR.

These reforms should facilitate the more dynamic trading of capacity and a more liquid wholesale gas market by:

- reducing search and transaction costs involved in trades;
- enabling shippers to obtain competitively priced un-nominated capacity;
- improving the incentives for shippers to trade capacity;
- reducing actual or perceived discriminatory access to capacity; and
- improving the information on which decisions in the sector are made.

4.1 Introduction

Under the contract carriage arrangements for gas transmission use in eastern Australia outside of the Victorian DTS, shippers must obtain pipeline capacity in order to transport gas on pipelines. A shipper can obtain capacity via either:

- The primary capacity market – for new or existing capacity sold by pipeline owners to shippers – which is typically characterised by long term contracts, allowing for the management of risk in investment in a large, long-lived asset, and certainty of access for those looking to supply gas under long term contracts to end-users.

- The secondary capacity market – for capacity that has already been sold to shippers – which allows shippers to trade with each other to fine tune their capacity positions to match their increasingly variable gas positions.

The achievement of the NGO in general, and the Energy Council's Vision in particular, depends critically upon a well-functioning gas transmission sector. Ready access to competitively priced pipeline capacity will reduce the costs associated with trading gas in the wholesale markets supporting the establishment of a liquid market with an efficient reference price.

Through its Pipeline Regulation and Capacity Trading Discussion Paper[63] consultation process, the Commission has identified priority issues relating to capacity markets that must be addressed in order to achieve the Council's Vision. These priority issues are:

- there appear to be limited incentives on shippers to trade capacity amongst themselves in the secondary capacity market;

- the price at which contracted but un-nominated capacity is sold does not always appear to reflect the value of that capacity;

- actual or perceived discriminatory access to either primary or secondary capacity;

- high transaction costs; and

- information deficiencies.

The Commission is recommending a suite of reforms that it considers will work together to collectively address the issues identified, balancing industry-led action with regulatory oversight.

Most of the reforms are targeted at improving access to secondary capacity, or providing information that would help with price discovery in that market. From its

63 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Pipeline Regulation and Capacity Trading Discussion Paper, September 2015.

discussions with the ACCC, the Commission understands that while longer-term secondary capacity trading (for capacity of greater than six months in length) has occurred, shorter-term secondary capacity trading is far rarer. More efficient trading of capacity between shippers will allow shippers to adjust their capacity positions in line with, and to facilitate, potentially increasingly dynamic wholesale gas market positions.

Over the course of the review, the Commission has identified concerns with outcomes in the market arising from a lack of incentives on pipeline owners to offer primary capacity at a price expected in a workably competitive market, or to provide a level of service in the secondary market commensurate with what would be expected in such a market.[64]

However, feedback received from stakeholders has tended to suggest that there are more pressing areas of focus for this review regarding the reallocation of capacity between shippers. The Commission has consequently developed the package of measures described in this chapter which are targeted specifically at addressing these issues.

While it is not recommending broader changes to the current regime for the economic regulation of pipelines at this stage, the Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In its work, the ACCC will be able to draw upon information gathering powers that are not available to the AEMC.

In the event that the ACCC was to find that there are issues to be addressed in relation to the incentives acting on pipeline owners – or in relation to the ability of the current regulatory regime to act as an effective constraint on these – the Commission may look to supplement its draft recommendations in this regard.

The remainder of this chapter describes the Commission's recommended regulatory changes with regard to pipeline capacity markets, and their rationale.

4.2 Recommendation 1: Auction for contracted but un-nominated capacity

The Commission recommends that an auction for contracted but un-nominated capacity with a regulated reserve price be introduced on all pipelines.

64 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Pipeline Regulation and Capacity Trading Discussion Paper, September 2015, pp. 12-14.

Box 4.2 What is contracted but un-nominated capacity?

Currently, shippers that have contracted capacity on a pipeline are required to nominate their usage for the next day by a defined time on the day before. The nomination cut-off time is defined in the GTA between shipper and pipeline owner. Typically, beyond the nomination cut-off time, any capacity that the shipper has contracted but not nominated to use is "lost" to the shipper, and the pipeline owner is able to re-sell this capacity to another shipper who might value it. The pipeline owner receives the revenue from this re-sale.

The capacity is resold on a firm[65,66] basis, because the shipper that has originally contracted the capacity typically has no priority beyond the nomination cut-off time over any capacity that it does not nominate. When resold by a pipeline owner, this capacity is typically also referred to as "as-available" capacity.

The price at which contracted but un-nominated capacity is resold is set commercially between the pipeline owner and the shipper wishing the purchase the capacity.[67] Typically, the price of firm day-ahead capacity is higher than that of long term services sold on a take-or-pay basis, which pipeline owners have suggested reflects the lower asset stranding risk faced as a result of long term take-or-pay contracts.[68]

Auctions should be held for all contracted but un-nominated capacity on pipelines as soon as practicable after the nomination cut-off time.

The auction would have a reserve price determined by a methodology approved by the AER. The reserve price would be set to allow the pipeline to recover at least any additional cost it incurred in providing the capacity. Put another way, capacity would not be allocated to shippers whose bids for that capacity did not indicate that they valued it greater than the cost of its provision.

Pipeline owners would continue to receive the revenue from the sale of un-nominated capacity (ie, they would receive the revenue generated through the auction) as opposed to the revenue being transferred to the shipper which originally held the capacity.

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65 The Commission understands that the un-nominated capacity resold after the nomination cut-off time can be marginally less firm than nominated capacity because it is interrupted first in the case of operational curtailment (for example, because of unplanned maintenance).

66 The Commission understands that in some cases, the nomination cut-off time is not strict. That is, shippers may be able to re-nominate capacity beyond the nomination cut-off time *on a firm basis*, meaning that any un-nominated capacity that is sold to another shipper is done so *on a non-firm basis*. These arrangements appear rare.

67 The price could be regulated for covered pipelines if the AER determined it to be a reference service within an access arrangement. The AER is required to make this decision on the under rule 101, based on whether the service is likely to be sought be a significant part of the market.

68 See, for example, Pipeline Regulation and Capacity Trading Discussion Paper submission: Jemena, pp. 4-5.

The mechanism would not apply to the sale of previously uncontracted capacity. Requiring uncontracted capacity to be sold in the auction might unnecessarily impact the primary capacity market.

The clearing price and volume of capacity cleared in the auction would be made transparent.

4.2.1 Rationale for recommendation

The recommended auction is intended to:

- improve incentives for shippers to trade capacity;
- provide non-discriminatory access to contracted but un-nominated capacity at a price consistent with that expected in a workably competitive market;
- allocate capacity to the shippers that values it the highest as indicated in their bids; and
- allow for better informed decision making by shippers and other parties, who have full transparency of the outcomes of the auction.

These considerations are discussed below.

Improved incentives for shippers to sell access

A shipper with contracted capacity currently has an incentive to sell unwanted capacity prior to the nomination cut-off time, in order to recoup some revenue that would otherwise be lost to that shipper. This might occur immediately before the nomination cut-off time, or at any time before, depending on the value it placed on holding on to the capacity in case it is required.

However, the Commission considers that some shippers may have a countervailing incentive not to sell capacity. Determining the likely future value of capacity and making a judgement whether to sell it is not a core business function for many shippers. The cost and effort of doing so, and the risk of being short of capacity if the sale occurs a long time before the nomination cut-off time, may exceed the revenue generated. The Commission recognises these issues, and is recommending a suite of measures to help reduce transaction costs and inform shipper decision making, as described in section 4.3.

As the only seller of capacity beyond the nomination cut-off time, the pipeline owner has the ability and incentive to price contracted but un-nominated capacity above levels expected in a workably competitive market. The Commission is concerned that high prices for such capacity, *in combination with the shippers' limited incentives to trade*, may be resulting in inefficient outcomes that the recommended auction might address.[69]

In instances where shippers simply forego the opportunity to sell capacity because it is not core-business, a prospective shipper's alternative is to purchase contracted but un-nominated capacity from the pipeline owner. However, high prices for this capacity may be pricing prospective shippers out of the market. The auction would provide prospective shippers the opportunity to purchase competitively priced capacity.

An incumbent shipper may also know that the potentially high price of un-nominated capacity sold by pipeline owners may limit entry by shippers that are its competitors in a related market. An incumbent shipper may therefore decline to sell capacity prior to the nomination cut-off time to gain a competitive advantage. Were prices for contracted but un-nominated capacity to be determined through a competitive auction, a shipper that holds capacity would be less able block a prospective competitor's access to pipeline capacity. Shippers that hold capacity might then have a stronger incentive to sell capacity prior to the nomination cut-off time (even if it is selling to a competitor), rather than the pipeline owner recouping the revenue for that sale, stimulating the secondary capacity market.

Non-discriminatory access to competitively priced capacity

The auction provides an opportunity for shippers to access contracted but un-nominated capacity on a competitively priced basis. Through the transparency inherent in the auction, access is also guaranteed to be provided on a non-discriminatory basis.

Non-discriminatory access to transportation capacity is critical if market participants are to be able to compete in upstream or downstream markets, while even the perception of discrimination may deter entry.[70] Actual or perceived discrimination can therefore inhibit competition in upstream or downstream markets, and thus limit the development of liquidity.[71]

As a result, all participants must be able to have (and know that they are able to have) access to gas transportation services on the same basis – that is to say, that there should be no undue price discrimination.[72,73] A transparent auction provides this.

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69 Pipeline Regulation and Capacity Trading Discussion Paper submissions: QGC, pp. 1-4, Encana pp. 7-8, 27-28.

70 Pipeline Regulation and Capacity Trading Discussion Paper submission: Encana, p. 6; FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 10.

71 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 31.

72 Price discrimination occurs when different prices are charged for the same product. This does not mean that all pipeline capacity must be sold at the same price. There may be price differences due to differences in the products (i.e. short term versus long term products, or the same duration product at two different times). Also customers may pay different prices for the same product as a result of auction outcomes. Undue price discrimination arises where the same product is sold for a different price without any objective justification.

Efficient capacity allocation

Auctions provide a market based mechanism to price and allocate potentially scarce capacity. Through their bids, shippers indicate the value they place on the un-nominated capacity. The auction would result in the un-nominated capacity being made available to any shipper that values it greater than the cost of its provision, and, in the case that there is more demand for un-nominated capacity than that available, to the shippers that value it the highest.

Having said this, the presence of the auction may result in more capacity being traded *prior* to the nomination cut-off time into the possession of the shipper which values it the most. This is because of the improved incentives for shippers to sell capacity and the measures to reduce transaction costs and facilitate frictionless secondary capacity sales between shippers (described in section 4.3).

Better informed decision making

Markets operate well when parties have sufficient information to make informed decisions. The volume and price information produced through the daily auction may inform market participants in their production, consumption, investment and risk management decisions.

4.2.2 Recommendation tradeoffs

The Commission acknowledges that there may be tradeoffs associated with the recommended auction. These tradeoffs, together with the Commission's analysis, are discussed below.

Investment signals

As noted in our discussion paper,[74] there is a concern that releasing short term capacity at potentially low prices might undermine incentives to underwrite new additional capacity. This concern is echoed in a number of submissions to that paper.[75]

The Commission acknowledges that on some occasions, shippers would be able to access very-short term capacity at a potentially low price (ie, at or just above the reserve price) on the occasions that they require it, without the long term commitment of a take-or-pay contract used to underwrite investment. This could, theoretically, create a free-rider effect, whereby shippers do not underwrite capacity because they are able to buy cheaper capacity underwritten by another shipper.

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73 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 10.

74 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Pipeline Regulation and Capacity Trading Discussion Paper, September 2015, pp. 39, 43.

75 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Stanwell, pp. 2, 4; APA, pp. 13, 33; APGA, p. 11; APGA, Submission to the ACCC East Coast Gas Inquiry Issues Paper, pp. 41-46; Epic Energy, Stage 1 Discussion Paper submission, p. 3.

However, the Commission does not consider that this is likely to be a material issue in practice for day ahead auctions of contracted but un-nominated capacity. Very few, if any, shippers would be able to rely solely on day-ahead capacity to manage their gas needs, or the gas needs of their customers, over any medium to long term period. The majority of gas users are either relatively inflexible in their usage (for example, residential gas customers) or require a relatively consistent supply of gas to justify sunk investment in immovable assets (for example, a factory).

Relying on capacity purchased through the auction would entail both price and volume risk. While prices could be low at some times (at or just above the reserve price), at other times, when the demand for capacity is high, the auction would be expected to clear at a high price. When demand is high enough, all contracted capacity will be nominated – leaving no capacity available for sale at the auction.

Most shippers will therefore require long term contracts (used to underwrite capacity), with the ability to fine-tune capacity requirements on an ongoing basis. The recommended auction serves to improve the ability of all shippers to fine-tune their capacity requirements without affecting the requirement for long term contracts that underwrite new investment.

Existing nomination and re-nomination rights

In our discussion paper we raised the concern that a firm day-ahead UIOLI mechanism could disrupt existing nomination and re-nominations procedures in GTAs. A number of stakeholder submissions also raised this concern.[76]

For example, nomination cut-off times are defined in GTAs between shippers and pipeline owners, negotiated based on the commercial and operational requirements of both parties. As such, the nomination cut-off times can vary, even on the same point-to-point route. While there may be merit in harmonising the nomination cut-off times (in order that an auction for un-nominated capacity can proceed immediately afterwards), this may impact nomination and re-nomination rights and operational requirements for shippers and pipeline owners.

It may be appropriate to consider harmonisation of nomination cut-off times as part of the harmonisation of the gas day start time, as recommended in stage 1 of this review[77], or through a standard developed by industry. It may also be appropriate that the capacity nomination cut-off is set with regard to any timing requirements relating to nominations for the gas commodity.[78]

Notwithstanding the above concerns, an important advantage of the auction mechanism proposed is that it would not substantially impact existing capacity rights

76 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Stanwell, p. 2; Esso, p. 1; ESAA, p. 3; Origin, p. 1; APLNG, p. 2.

77 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, July 2015, pp. 41-42.

78 Pipeline Regulation and Capacity Trading Discussion Paper submission: ESSO, p. 1.

held by shippers – shippers typically already lose their firm capacity rights at the nomination cut-off time.[79] It might, however, result in a higher utilisation of the pipeline and so an implicit reduction in the firmness of capacity re-nominations that some shippers may rely on during the gas day.

These matters would have to be carefully considered when designing the auction.

Regulatory burden

Designing, building, operating and participating in the auction would not be without direct cost for pipeline owners, shippers and regulators.

The Commission has not undertaken any detailed analysis into the materiality of these costs. As with all regulations, likely direct costs would have to be taken into consideration prior to an implementation decision.

4.2.3 Implementation of auction for un-nominated capacity

The auction for un-nominated capacity could be implemented by making a requirement under the NGL for parties undertaking pipeline transmission transportation activities to be registered with AEMO, in much the same way that various parties are required to register under the National Electricity Law.[80] Consideration would need to be given to how to define the parties that require to be registered.

Obligations would then be placed on pipeline owners under the NGR or NGL to undertake the auction, including an obligation to offer all spare capacity in the auction and sell it at the price determined in the auction.

Consideration would need to be given as to the appropriate level of detailed prescription for the auction in the NGL, NGR, and potentially procedures or guidelines. One approach might be to place design principles in the NGR, for the AER to create more detailed procedures in keeping with the design principles, and for the pipeline owner to apply the procedures with oversight from the AER.

Consideration would also need to be given to any transitional issues that might arise, including where the recommended auction is not in keeping with existing terms in contracts between shippers and pipeline owners.

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79 Some shippers may have re-nomination rights such that the nomination cut-off time is not fixed and definitive, although we understand these provisions to be very rare. See Pipeline Regulation and Capacity Trading Discussion Paper submission: Stanwell, p. 4; Santos, p. 4. To the extent that shippers currently have a firm right to re-nominate capacity beyond the nomination cut-off time, consideration could be given to auctioning this capacity on a non-firm basis to other shippers. Some shippers have also noted that a UIOLI mechanism may impact a shipper's ability to utilise the linepack park and loan tolerance associated with its capacity. See Pipeline Regulation and Capacity Trading Discussion Paper submission: AGL, p. 2.

80 National Electricity Law, Schedule – National Electricity Law, Division 1.

4.2.4 Design considerations

In arriving at its draft recommendation, the Commission recognises that there are a number of detailed design decisions that would need to be made prior to the implementation of the day-ahead auction in addition to those discussed above.

The Commission welcomes feedback on any considerations noted below or further matters raised by stakeholders.

Setting the reserve price

The intention of the reserve price is to ensure that capacity is not used where it is valued less than the cost of its provision, and to provide the pipeline owner with the opportunity to recover its costs.

In circumstances where the pipeline owner is recovering much of its capital costs through long term, take-or-pay contracts, an appropriate reserve price might theoretically be the short run marginal cost of capacity – operational costs required to provide an addition unit of capacity.

In practice, the short run marginal cost is likely to differ based on a variety of circumstances. For example the amount and flow of gas in the pipelines on any particular day will influence how much compression is required to flow the gas. There is therefore likely to be a tradeoff between, on the one hand, accurately setting the reserve price on any given day to match the actual short run marginal cost (so that capacity is not over- or under-utilised) and, on the other hand, the cost and complexity that would arise from doing so.

It might, therefore, be appropriate to set the reserve price based on the forecast average short run marginal cost, and reset this periodically or where it has become demonstrably inaccurate.

The governance of setting the reserve price would also have to considered. While the AER could directly set the reserve price, it may be more appropriate for the AER to approve a formula or mechanism for setting the price which would be created and applied by the pipeline owner. The NGR might specify the principles upon which the AER would approve the formula or mechanism.

Further consideration is required on these matters, drawing on the experience of setting reserve prices for auctions of other goods and services, and overseas.

Determining the amount of capacity to be auctioned

Determining the amount of un-nominated capacity to be auctioned also needs to be considered. As with the reserve price, the amount of un-nominated capacity may vary over time, not only with the amount of nominated capacity, but also with, for example the amount of line pack or the timing of planned maintenance.

If set by the pipeline owner, it may choose to withhold some capacity in order that the auction clearing price is increased. As with the reserve price, it might therefore be appropriate for the amount to be set either independently (for example, by the AER), or by the pipeline owner in accordance with a regulator approved formula or mechanism. Again, the NGR might specify the principles upon which the AER would approve the formula or mechanism, potentially with regard to the capacity that could have been nominated but was not. Regardless, is likely that the process will require technical engineering information and expertise in order to make an informed decision.[81]

Pipelines that are not fully contracted

In cases where a pipeline has a low proportion of its capacity contracted, capacity released in the auction may compete with uncontracted spare firm capacity. Shippers may prefer to buy capacity in the auction for contracted but un-nominated capacity (at a potentially low price) rather than buy uncontracted capacity directly from the pipeline owner unless that price was competitive with the expected auction price. Pipeline owners may therefore be unable to recover investment costs if the auction clearing price was consistently at or near the short run marginal cost.

The auction could be made to only apply on fully contracted pipelines, but this approach might encourage pipeline owners to only contract a proportion (say, 99 per cent) of their capacity in order to avoid the requirement to auction any contracted but un-nominated capacity. As a result, it may be appropriate that:

- the pipeline owner is exempt on a case-by-case basis from the requirement to release contracted but un-nominated capacity in the auction; or
- the auction reserve price is set above the short run marginal cost, to provide the pipeline owners an ability to recover capital costs.

Auction design

Designing allocation processes based on auctions is often complex. In the case of auctioning contracted but un-nominated capacity:

- there would be multiple different products that could be bought in the auction, for different amounts of capacity along different transportation paths; and
- shippers may require contingent bidding (that is, their bid for a particular segment of capacity is contingent on them winning another segment of capacity, and vice versa).

81 In the US, there have historically been concerns over "withholding", for example in connection with the California "energy crisis". The FERC preliminary decision in a case related to the El Paso pipeline shows how the analysis of capacity withholding on El Paso included FERC comparing the certified pipeline capacity to the actual flow and available capacity posted by the pipeline. See FERC, Docket No. RP00-241-006, Initial Decision, September 23, 2002, p. 10.

The auction might be designed to take account of such complexities.

On the other hand, it is important that the design of the auction is fit-for-purpose. There may be relatively few transactions which occur through the auction if shippers have an improved ability and incentive to trade capacity amongst themselves prior to the nomination cut-off time, meaning that capacity might already be efficiently held by the shipper that values it the most at the time of the auction.[82]

Terms and conditions of capacity and service standards

The terms and conditions for the un-nominated capacity sold through the auction would have to be set with regulatory oversight, to ensure that the service standards that the pipeline owner was required to meet were reasonable, and to protect the pipeline owner, given that it would be required to sell capacity.[83]

For example, consideration would have to be given to the liability that a pipeline owner would face were an unplanned interruption to capacity to occur. In this instance it may be appropriate that purchased previously un-nominated capacity be curtailed ahead of originally contracted capacity (as some pipeline owners currently do) and that the pipeline owner would have limited liability for any loss of earnings on the part of the curtailed shippers.

Covered pipelines

Care would need to be taken to ensure that the requirement of the pipeline owners to auction contracted but un-nominated capacity is appropriate for covered pipelines, and does not contradict an access arrangement determined by the AER.

Further consideration is also required regarding whether the requirement for a pipeline owner to conduct an auction for contracted but un-nominated capacity is feasible and appropriate for pipelines that have been granted a 15-year coverage exemption as a greenfield pipeline.[84]

Pipelines servicing a single facility

Some pipelines serve only a single facility and consequently may only be used by a single shipper. Examples might include pipelines serving LNG export facilities or gas fired generation power plants. In such circumstances, an auction for un-nominated capacity may achieve little as there would be no prospect of un-nominated capacity

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82 There is a considerable body of literature on auction design. For an introduction to the theory of auctions, see F. M. Menezes and P. K. Monteiro, 2008. *An Introduction to Auction Theory,* Oxford University Press, and for an extensive review of the theory and application of auctions to public policy see Milgrom, P. 2004. *Putting Auction Theory to Work*, Cambridge University Press and Klemperer, P. 2004, *Auctions: Theory and Practice*, Princeton University Press.

83 Pipeline Regulation and Capacity Trading Discussion Paper submissions: AGL, p. 2; Origin, p. 4; Energy Australia, p. 2; Santos, p. 4.

84 Such exemptions are regulated under the NGL, Chapter 5.

being resold to another shipper. It may be appropriate for the auction to not be required in such circumstances.

4.3 Recommendation 2: Secondary trading platform with information reporting requirements and standardised capacity products

Recommendation 2 has three inter-related components that work to together to reduce transaction costs, information deficiencies and actual or perceived discriminatory access to secondary capacity.

Firstly, prior to the nomination cut-off time, shippers are able to trade capacity amongst themselves. To better facilitate this, the Commission recommends that pipeline owners would be required to operate an internet based capacity trading platform(s) where shippers can anonymously post capacity that is for sale or wanting to be bought. Each pipeline owner might be required to create its own platform, or alternatively to jointly run one platform if there were coordination benefits from doing so.

Where trades were conducted through the platform, payments for the transfer of capacity might be made via the platform, and so handled by the pipeline owner.

Secondly, while it might not be compulsory for shippers to use the secondary trading platform, information on all trades, including those struck outside of the capacity trading platform(s), would be required to be published on the capacity trading platform website(s). This information would show:

- how much capacity has been sold, and for what duration;
- the price of the capacity sale, including the price for any related services such as renomination; and
- any other terms and conditions which would reasonably impact the price of the transaction (for example, whether the sale is firm or interruptible).

Shippers would not be allowed to transport gas on behalf of a third party (a practice known as "bare transfers"[85]), circumnavigating reporting requirements.[86]

Thirdly, the Commission recommends that standardised primary capacity products be required to be developed by industry, but with regulatory oversight, with the intention of precipitating the standardisation of secondary capacity that is traded.

Standardisation might be made to a wide range of characteristics of capacity. Standardisation might be required on:

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85 Where an existing shipper's rights (or part thereof) are temporarily transferred to the counterparty but the existing shipper remains responsible for the financial and operational obligations in the GTA (such as pipeline nominations).

86 This is known as the "shipper must have title" rule in the US. See FERC Order 636 (1992).

- the capacity product itself, such as its duration;
- associated rights and process, such as nomination and renomination rights, scheduling, curtailment, balancing requirements, and rights to line-pack and storage; and
- other terms and conditions such as prudential requirements, and those relating to liability and indemnity.

4.3.1 Rationale for recommendation to introduce platform, information reporting requirements and product standardisation

Due to the currently confidential nature of trades, it is not possible to determine how frequently secondary transactions occur. Anecdotal evidence, however, suggests these transactions are occurring for longer term capacity (greater than six months) but rarely in the short term.

The lack of trade in shorter term capacity (ie, less than six months) could be because the value placed on the capacity by its current holder is greater than the value placed on it by any potential buyer, in which case the capacity is held by the party which values it most highly – an efficient outcome.[87] Put another way, the demand for secondary capacity could be low.

However, the apparently low number of shorter term capacity transactions indicates that capacity may not be being allocated through commercial transactions to the party that values it the highest. In addition to the discussion in section 4.2.1 regarding the incentives on shippers to trade capacity, the Commission has identified a number of other issues relating to secondary capacity trades, particularly for low value trades (eg, shorter term trades), which may be limiting shippers' ability and incentive to transact:

- There may be a lack of information on the existence of prospective buyers and sellers of capacity. Buyers and sellers are unable to find each other, and so trades that would otherwise occur do not.
- Both buyers and sellers may have limited information on the market. This may lead to additional costs as the parties attempt to understand the market value and to ensure that they are being offered capacity on a non-discriminatory basis.
- GTAs are typically customised, which may be resulting in difficulties in quickly and inexpensively determining the value of the capacity rights being sold in order to make a trade. Customisation also limits the depth of the market as a range of different products splits the market.

These issues may be particularly problematic for trades of capacity in the immediate future (where parties need to find each other and agree to make a trade quickly). These

87 The value placed on capacity include the value each shipper places on the *option* to use the capacity, given that a shipper is required to decide whether or not to sell or buy capacity some time prior to knowing whether that capacity will be required.

trades are likely to become of increasing importance as market dynamics change in eastern Australia.

Capacity rights are typically also specified with regard to the injection and withdrawal locations, reducing potential trading partners, reducing liquidity and increasing search costs.[88] Stakeholders have commented that there can be technical impediments to trading capacity on pipelines with multiple injection and withdrawal points - for example, the Roma to Brisbane Pipeline - because the capacity on one part of the pipeline may depend on what is being injected and withdrawn on another part of the pipeline.[89]

The Commission acknowledges that steps have recently been taken by the market to reduce search and transaction costs and improve the ability of shippers to trade capacity. For example, both APA and Jemena have established capacity listing websites, described in Box 4.3.

Box 4.3 Capacity trading websites

To facilitate trades, 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.[90]

APA's platform currently allows capacity on the South West Queensland, Carpentaria, Moomba to Sydney and Roma to Brisbane pipelines to be listed. 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.

APA's website includes summary trading information, which suggests that a limited amount of capacity has been traded to date on the Roma to Brisbane Pipeline.

Despite these initiatives and others made by industry, and other regulatory changes underway,[91] the Commission considers that further regulatory changes are required to reduce search and transaction costs.[92] By requiring the creation of a capacity trading platform(s), requiring that shippers to post certain information on all capacity trades, and standardising capacity products, the three inter-related components of recommendation 2 are intended to:

- reduce search and transaction costs for shippers because they could:

88 AGL, Stage 1 Discussion Paper submission, p. 5; QGC, Stage 1 Discussion Paper submission, p. 2.

89 K Lowe Consulting, *Gas Market Scoping Study, A report for the AEMC*, 2013, p. 124.

90 These websites can be accessed via the AEMO gas Bulletin Board or directly via http://capacitytrading.apa.com.au/ and http://jemena.com.au/industry/pipelines/capacity-trading, respectively.

91 AEMC, *Enhanced Information for Gas Transmission Pipeline Capacity Trading, Draft Rule Determination*, October 2015.

92 Pipeline Regulation and Capacity Trading Discussion Paper submission: AEMO, p. 1.

- simply and anonymously post or review buy- or sell-offers on the platform(s), reducing costs and speeding the process; and
- more quickly assess the value to them of a standardised capacity product compared to a customised product;[93]

- allow shippers to quickly assess whether a future trade is consistent with historical transactions, because of the information on trades provided through the platform;
- increase liquidity, as standardisation may result in more buyers and sells for similar capacity products; and
- provide shippers with confidence that future secondary trading transactions are non-discriminatory. Unlike the current capacity trading facilities operated by the pipeline owners, publishing the price of the trades, plus any information relevant to that price, would give shippers confidence that the access price and conditions were reasonable and being provided on a non-discriminatory basis. Shippers would be less reluctant to enter into a trade, and small shippers may consider their negotiation positions strengthened, reducing barriers to entry and enhancing competition. Anonymity of trades posted through the trading platform might also help in this regard.

4.3.2 Recommendation tradeoffs

Stakeholders have raised a number of tradeoffs regarding a capacity trading platform. These tradeoffs, and the Commission's assessment, are given below.

Anonymity, confidentiality and information provision requirements

Some stakeholders have raised concerns that publishing information on capacity trades may reveal to the market a shipper's position in a related market, which could be disadvantageous to that shipper and reduce its incentives to trade.[94] For this reason, both prospective trades posted on the trading platform, and information on actual trades conducted through or outside of the platform, could be anonymous. Although the pipeline owner, as operator of the platform, would be aware of the counter-parties to the trade, this information would not be published.

The Commission recognises that even if the names of the counter-parties were not published, it may be possible to deduce the likely counter-parties given a number of characteristics of the actual or prospective trade – for example, the point-to-point location of the capacity in question. Further steps might be taken to protect anonymity.

93 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Jemena, p. 5; MEU, p. 16; APGA, p. 3; Energy Australia, p. 2; Santos, p. 2; GDF SUEZ, p. 3.

94 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Esso, p. 1; APGA, p. 9; Origin, pp. 2-3; Santos, p. 3; MEU, p. 21.

On the other hand, in the US the FERC considered the issue of anonymity at length and considered that, despite these concerns, full transparency is warranted.[95]

The Commission will continue to assess the appropriate level of anonymity for capacity trade reporting.

Cost of developing capacity trading platform and standardisation

Developing the capacity trading platform, shipper interfaces with the platform, and standardised capacity products would entail costs for pipeline owners, shippers and regulators. Costs may be minimised by building on existing capacity trading platforms.

The Commission has not yet assessed these costs, and any decision to implement this recommendation would require such an assessment.

Standardising of capacity rights could be an involved process both for industry and regulators. Nevertheless, the Commission considers that the benefits of doing so are likely to be substantial. Experience can be drawn in this regard from the standardisation process undertaken in the US, discussed below.

Standardisation

The intention of standardisation, as discussed in section 4.3.1, is to reduce search and transaction costs (as shippers would be able to quickly determine the value of a capacity product for sale) and increase liquidity (as a plethora of different products splits the market).

On the other hand, customisation of capacity rights provides value to at least one or the other of the shipper or pipeline owner (or else these parties would not agree to them in a GTA) – were standardised products to be made compulsory, this would inevitably reduce the ability of these parties to fine-tune their products.[96]

Bearing this trade-off in mind, the extent of standardisation would have to be carefully considered:

- Along some or all characteristics, product or process standardisation could be voluntary, with shippers and pipeline owners able to negotiate away from the standard.[97]

- For each characteristic it may be unnecessary to have a unique standard, but instead a range of standards which the shipper and pipeline owner could choose between when striking their GTA. This may serve to allow some fine-tuning of

95 FERC, Order 637 (2000), section IV.A.

96 Pipeline Regulation and Capacity Trading Discussion Paper submissions: APGA, p. 7; ESAA, p. 2.

97 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Origin, p. 2. AEMO, p.1. In the US, FERC Order 637 (2000) requires that negotiated contracts be submitted to FERC for review.

capacity products while cutting down on the plethora of potential products that could exist without standardisation.

- It may not be necessary to standardise (in full or in part) the primary capacity market in order to facilitate a sufficiently standardised secondary capacity market. Conversely, standardisation may be required in the secondary capacity market itself.

Standardisation may have transitional issues as existing GTAs are not currently standardised. Clearly, converting existing GTAs to standardised GTAs may impact on the value of these GTAs for either the shipper or pipeline owner. It may be appropriate to grandfather these arrangements where counter-parties cannot agree to a contract variation.[98] In this case it would be particularly important that all information relevant to the value of the capacity be published on the capacity trading website.

Standardisation may be aided through regulated flexibility in receipt and delivery points. This is discussed in more detail in section 4.3.4.

Further work is required to assess the appropriate extent and characteristics of standardisation.

4.3.3 Implementation of capacity trading mechanism and standardisation

In keeping with recommendation 1, recommendation 2 could be effected via a requirement, under the NGL, for pipeline owners and shippers to register with AEMO. Consideration would need to be given to how to define the parties that require to be registered.

As with recommendation 1, obligations would then be placed on registered parties through the NGL and/or NGR:

- for registered shippers, to publish information relating to capacity trades on the capacity trading platform (and, to conduct trades through the platform if this was considered appropriate);
- for registered pipeline owners, to create and run the capacity trading platforms (if this was considered appropriate), and, where necessary, facilitate trades.

Consideration would need to be given to the process by which standardisation might occur. We note that a similar approach was undertaken in the US, where an industry grouping (initially GISB (the Gas Industry Standards Board), now NAESB (the North American Energy Standards Board)) continues to develop standards and protocols under FERC oversight.[99] Standardisation has occurred in five broad areas:

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98 Pipeline Regulation and Capacity Trading Discussion Paper submissions: Stanwell, p. 3; Origin, p. 2.

99 See FERC Order 587 (1996), FERC Order 637 (2000) section IV.D, and *Code of Federal Regulations*, Title 18, part 284.12.

nominations, gas flows (balancing), invoicing, capacity release, and electronic communication.

4.3.4 Design considerations

There are a number of specific design features and considerations for the capacity trading platform that would need to be determined. The Commission welcomes feedback on the discussions below, as well as any other matters that stakeholders wish to raise.

Compulsory trading through the platform

While the information provision requirements of the recommended approach would provide shippers with *confidence* that the access price and conditions were reasonable and being provided on a non-discriminatory basis, such an approach does not *guarantee* non-discriminatory access. A shipper would be able to "pre-arrange" capacity release (whereby they find counter-parties to a trade outside of a capacity trading platform), to the exclusion of other potential counter-parties, or refuse to enter into a trade posted on the trading platform if the counter-party was not to its liking (assuming it was able to determine who the counter-party was).

In the US, under certain circumstances the process by which capacity is traded between shippers guarantees non-discriminatory access.[100]

In most circumstances, shippers wishing to sell or buy capacity are able to simply post their proposed bid or offer on the capacity trading platform. Bids or offers are received from prospective counter-parties and it is the pipeline owner's responsibility to determine which shipper has submitted the highest bid. As such, there is no ability to discriminate between counter-parties.

Shippers can alternatively "pre-arranged" trades, but before the trade can be effected it must be posted on the pipeline’s capacity trading platform so that other shippers have the opportunity to beat the pre-arranged bid. Again, this provides the opportunity for all shippers to compete for capacity trades on an equal basis, although there are two exceptions to this:

- when the pre-arranged price has been agreed between the shippers at the maximum regulated rate; or
- when capacity releases are for less than one month, which the Commission understands is a materiality threshold.

Consideration should be given to whether capacity trades should be required to be conducted through auctions or open seasons (and under what circumstances) in order to guarantee (rather than merely provide confidence for) non-discriminatory access. Put another way, consideration should be given to whether pre-arranged trades

100 *Code of Federal Regulations*, Title 18, part 284.8a.

outside of the platform(s) should be permitted (and under what circumstances). Regardless, information regarding the capacity release would still be required to be published.

Segmentation and flexibility in receipt and delivery points

In the US, pipeline owners are required to allow shippers to "segment" the length of their point-to-point capacity into component lengths under certain circumstances.[101] Shippers are then able to sell segments off independently, with the potential to maximise the volume and value of capacity trading. Segmentation is subject to operational constraints determined independently by engineers.

The Commission has not yet determined the appropriateness of regulated segmentation in eastern Australia, and welcomes feedback in this regard.

The US regime also provides for some flexibility in receipt and delivery points. Pipelines are required to permit shippers access to "secondary" receipt and delivery points on an interruptible basis, in addition to a "primary" (firm) receipt point(s).

Not only might this flexibility provide additional value to incumbent capacity holders, it may also make the capacity products more standardised, and so fungible. Capacity with multiple (secondary) receipt points might be valuable to shippers not at the primary receipt point, if those shippers were willing to buy interruptible capacity.

Counterparty risk

Consideration should be given to how to appropriately manage any counterparty risk that may arise for the party that runs the platform, were payments for the trades made via that party.

4.3.5 Longer-term use it or lose it mechanism

The Commission does not recommend the immediate introduction of a long term UIOLI mechanism. However, should the recommended auction for contracted but un-nominated capacity combined with improvements to facilitate secondary capacity trading (described in this section) result in insufficient levels of trade, then the Commission recommends that the introduction of a long term UIOLI mechanism should be re-considered.

Under such a mechanism, shippers who systematically underutilise their contracted capacity would be required to surrender a defined proportion of firm capacity back to the pipeline owner for resale to another shipper. The capacity product released would be medium or long term (perhaps a month, season, or year). The underutilised capacity

101 See FERC Order 637 (2000), section III.B; FERC Order 637-B; *Code of Federal Regulations*, Title 18, part 284.7d.

would generally be determined through a retrospective review of flow and usage patterns.

Although not designed as such, the capacity re-sale process described in Box 4.2 is in effect a form of the day-ahead UIOLI mechanism described in the AEMC's discussion paper on pipeline regulation and capacity trading.[102] The introduction of an auction for contracted but un-nominated capacity (described in section 4.2) represents a refinement of this mechanism.

While a longer-term UIOLI mechanism might result in more (and more valuable) capacity being released to other shippers, it has two clear drawbacks compared to the recommended day-ahead UIOLI mechanism. The long term mechanism:[103]

- would impinge on the existing property rights of shippers (whereas the day-ahead mechanism recommended would improve the process by which capacity that has already been lost to a shipper is re-allocated to other shippers); and
- may have a more material impact on investment signals. Prospective shippers may be better able to meet long term capacity requirements by purchasing capacity released through the longer-term UIOLI mechanism, with the potential for free-rider effects.

Such a mechanism may be particularly useful for single shipper pipelines, where the ability to block competitive entry into a market is most prevalent.

4.4 Recommendation 3: Information regarding primary capacity trades made transparent

The Commission recommends that the actual (not advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price, be published.

4.4.1 Rationale for recommendation

The Commission considers that there is an issue regarding actual or perceived non-discriminatory access to primary capacity.[104] The price and other terms of primary capacity transactions are currently confidential, meaning that other shippers have no way to assess whether their own capacity purchases are non-discriminatory.

This may particularly deter new entry by shippers with smaller gas portfolios, who, unlike a large shipper, may consider that they do not have the market power to negotiate a good deal with the pipeline owner. Importantly, the perception of non-discriminatory access is as important as the practice of non-discriminatory access.

102 Pipeline Regulation and Capacity Trading Discussion Paper submissions: APGA, p. 12; Origin, p. 4.

103 Pipeline Regulation and Capacity Trading Discussion Paper submissions: APGA, p. 12; APA, p. 33.

104 Pipeline Regulation and Capacity Trading Discussion Paper submission: Encana, p. 4.

Even if, in practice, shippers are being charged the same tariff for the same service, if they perceive that they are not receiving competitively neutral treatment relative to incumbents then this may be sufficient to deter new entry.[105]

To the extent that pipeline owners are currently price discriminating, transparent historical prices, terms and conditions should place a discipline on pipeline owners not to undertake this practice. Even if price discrimination is not occurring in practice, transparency should give shippers confidence that this is indeed the case, and improve their negotiating power with the pipeline owners.

It would be important that not only the price of capacity is published, but also any terms and conditions that might impact the value of the capacity. For example, the requirements on market participants to balance their injections and withdrawals into and from the gas pipelines should not be unduly discriminatory. Otherwise, discrimination could be (or could be perceived to be) undertaken by lowering service standards (as opposed to increasing the price for the same service standard). Consideration would need to be given to specifically which information should be published.[106] The standardisation of capacity products (as discussed in section 4.3) may aid in this regard.

As with more information in the contracted but un-nominated market and the secondary capacity market, more information in the primary capacity market may result in more informed and potentially improved decisions by shippers and other participants. Such decisions not only include capacity procurement decisions, but also for consumption, production, investment and pipeline operations. More information would also enable regulators (such as the ACCC) to assess the prevalence of monopoly power in the primary capacity market.

4.4.2 Recommendation tradeoffs

The Commission has identified various potential tradeoffs regarding the provision of information about primary capacity transactions. These, and the Commission's assessment, are discussed below.

Anonymity, confidentiality and information provision requirements

As with the provision of information regarding secondary capacity trade (see section 4.3.2), the Commission is aware that the release of commercially sensitive information

105 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 31.

106 For example, in the US, for firm service, pipelines are required to post the following information, contemporaneously with the execution of the contract: the names of the parties to the contract; the contract number for the shipper receiving service and for the releasing shipper; the rate charged under each contract and the maximum rate, if applicable; the duration of the contract; the receipt and delivery points and zones or segments covered by the contract, as well as the common transaction point codes; the contract quantity, or volumetric quantity under a volumetric release; special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract; and any affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper. See FERC Order 637 (2000), pp. 177-178.

on primary capacity trades may adversely impact the shipper that is purchasing capacity. As a result, capacity purchases from pipeline owners could also be anonymous. Similarly, the Commission recognises that it may be possible to deduce the likely counter-parties of a trade from other information. The Commission will continue to assess the appropriate level of anonymity for primary capacity trades.[107]

Regulatory burden

As with the introduction of all regulations, consideration will need to be given to the likely regulatory burden that will arise for pipeline owners, shippers and other parties. The Commission has not yet assessed these likely costs.

4.4.3 Implementation of recommendation

As with recommendations 1 and 2, this recommendation could be implemented by requiring parties undertaking gas transmission activities to register with AEMO. Obligations would then be placed on registered pipeline owners to provide the relevant primary capacity trading information.

4.5 Summary of pipeline capacity market recommendations

A summary of the recommendations, and their rationale, are outlined in Figure 4.1 overleaf.

The Commission considers the recommendations to be a balanced and proportionate suite of reforms given the issues observed in the sector. They will provide market participants with an improved opportunity to trade capacity once they have improved incentives and ability to do so, supported by better information.

The Commission also considers the suite of reforms to be internally consistent and self-reinforcing. For example, the auction for contracted but un-nominated capacity provides improved incentives for shippers to trade capacity, but for these incentives to be effective, shippers must be able to do so quickly and at low cost – as provided for through recommendation 2. The reform will therefore be most effective when implemented as a package, rather than in a piecemeal fashion.

107 In the US the FERC considered the issue of anonymity at length and considered that, despite these concerns, full transparency is warranted. See FERC, Order 637 (2000), section IV.A.

Figure 4.1 Summary of pipeline capacity market recommendations

Recommendation	How capacity is priced	Capacity allocation process	Information transparency
1. Contracted but un-nominated capacity sold in an auction with a regulated reserve price	Competitively determined through auction with regulated reserve price: • Improves incentives for shippers to trade capacity • Provides access to competitively priced contracted but un-nominated capacity	Via transparent auction: • Guaranteeing non-discriminatory access • Allocation to party that values capacity highest as indicated in bids	Price, volume and other relevant information from the auction made publicly available: • Informing decision making
2. Capacity trading platforms mandated. Information on all secondary capacity trades must be published through the platforms Standardisation of capacity products to facilitate trading through the platform	Un-regulated, negotiated between shippers	Capacity trading platform provides an opportunity for shippers to reduce search and transaction costs Auction/open season for capacity sales may or may not be mandated Long-term UIOLI mechanism not currently recommended but should be reconsidered in the future if capacity trading remains illiquid	Price, volume and other relevant information from trades made publicly available: • Improving confidence that access is non-discriminatory • Informing decision making
3. Information relating to primary capacity market is made transparent	Un-regulated/regulated (depending on coverage of pipeline) with negotiation between shipper and pipeline owner	Un-regulated	Price, volume and other relevant information made publicly available: • Improving confidence that access is non-discriminatory • Informing decision making

Key:	No change	Less significant change	More significant change

5 Wholesale gas trading markets

Box 5.1 Summary of recommendations

The Commission recommends the following direction for the development of the wholesale gas trading markets on the east coast:

- Two primary trading hubs on the east coast, one in the north and one in the south, with common trading mechanisms applying to each.
- The Northern Hub to be defined as a physical hub at Wallumbilla, with the potential for a virtual hub at a later date.
- The Southern Hub to consist of a virtual hub covering the Victorian DTS, with an entry-exit regime for allocating capacity.
- Simplification of the STTM to a balancing role once liquidity has developed at the Northern and Southern hubs, and in pipeline capacity trading.

Combined with enhanced pipeline access arrangements and information provision, the Commission is of the view that the Energy Council's Vision is best met by focussing trade at two points - in the north by continuing to evolve the existing Wallumbilla GSH and in the south at a virtual hub covering the Victorian DTS.[108] Price discovery at both markets would occur via exchange-based trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible.

Exchange-based trading provides participants with greater flexibility in how they buy and sell gas than the current reverse auction mechanism. Day-ahead and balance-of-day spot products, and longer forward products, can also be traded on the exchange, creating transparency around future price expectations.

While not explicitly part of the Northern Hub, a second GSH at Moomba is likely to be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba could establish itself as a transit point for gas flowing between hubs, particularly given the recent announcement to connect the northern and eastern gas markets.

Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times.

108 Development of the Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access and information provision. These are set out in Chapters 4 and 6, respectively.

5.1 Development of the east coast gas market

As outlined in Chapter 3, the Commission recommends the following direction for the development of the gas trading markets on the east coast:

- Two primary trading hubs on the east coast, one in the north and one in the south, with exchange-based trading applying to each.
- The Northern Hub to be defined as a physical hub at Wallumbilla, with the potential for a virtual hub at a later date.
- The Southern Hub to consist of a virtual hub covering the Victorian DTS with an entry-exit regime for allocating capacity.
- Simplification of the STTM hubs to pure balancing markets once liquidity has developed at the Northern and Southern hubs, and in pipeline capacity trading.

As set out in Chapters 4 and 6, development of the Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access and information provision. In this respect, the package developed by the Commission is a congruent set of inter-related recommendations that mutually reinforce the objectives of each another.

Given the volumes of gas and number of participants on the east coast, the Commission sees a degree of risk in recommending an approach involving multiple hub locations and different market designs. In order to have confidence that a meaningful reference price for gas will develop, the Commission has sought to concentrate trading liquidity, to the extent possible, and recommend a trading approach that facilitates ease of use and understanding by participants.

The Commission is of the view that the Energy Council's Vision would be best met by focussing trade in the north at the existing Wallumbilla GSH and trade in the south at a virtual hub covering the Victorian DTS. Price discovery at both markets would be via exchange-based trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training where possible.

Exchange-based trading provides gas market participants with greater flexibility in how they buy and sell gas than the reverse auction mechanisms in the DWGM and STTM hubs. Day-ahead and balance-of-day spot products, and forward products past a week and a month can also be traded on the exchange, creating transparency around future price expectations. Exchange-based trading is also less administratively complex to implement, as complex pricing algorithms are not required to determine the market price. Further detail on exchange-based trading is provided in Box 5.2.

Box 5.2 Exchange-based trading and gas markets

Exchange-based trading involves buyers and sellers placing anonymous bids to buy gas or offers to sell gas using an electronic trading platform. The market matches bids and offers on price to execute a trade as is done on a stock market. All transactions on the trading platform are published as they occur to support liquidity and transparency.

Under the Commission’s recommended wholesale market design, participants can buy or sell gas through the exchange or trade bi-laterally outside the exchange. When a trade occurs, the facility operator is notified by the shipper and market operator, so that the existing physical nominations of the buyer and seller can be adjusted at the hub.

Trading occurs between predefined business hours on standardised, hub specific contracts. Exchange-based trading products can evolve over time to suit the requirements of participants. Some common contracts include: on-the-day; day-ahead; week-ahead; and month-ahead.

Participants will generally utilise a combination of exchange-based products, along with their bilateral contracts, in order to manage their gas portfolio needs. Continuous exchange trading facilitates the integration between the spot and forward markets through continuous trading of the forward products leading up to the gas day.

A liquid forward curve provides participants with transparency around the market's future price expectations for gas, say, a week ahead or a month ahead or even the following year. Financial derivatives to manage price risk are often developed over the most liquid of these physical products.

While not explicitly part of the Northern Hub, a second GSH at Moomba is likely to be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba could establish itself as a transit point for gas flowing between the east coast markets, particularly given the recent announcement to connect the northern and eastern gas markets via a new pipeline (see section 5.3.2).

Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times.

5.2 Southern Hub for trading gas

The Commission recommends that a virtual hub design continues to be applied in Victoria but with the following changes:

- Transition to **exchange-based trading**, similar to the Wallumbilla GSH, to replace the current reverse auctions process, which would include:
  - incentives on participants to trade gas on the market to balance injections and withdrawals; and
  - certainty of delivery through residual balancing actions conducted by the hub operator.
- Transition to an **entry-exit regime** for allocating pipeline capacity, to replace the current market carriage framework.

An important distinction between the proposed Southern Hub and the current Wallumbilla GSH model can be made in the certainty of delivery that market participants are provided.[109] Under the proposed model for the Southern Hub, a party purchasing gas from the exchange is guaranteed delivery through the balancing mechanism. This process is designed to ensure that small and large trading market participants will receive the gas they purchased with certainty.

As part of the DWGM Review, the Commission gave consideration to an option whereby the pipelines within the DTS, but outside of the inner Melbourne ring, would be transitioned to a contract carriage framework, consistent with the arrangements outside of Victoria.

After consultation with stakeholders, the Commission considers that the technical characteristics of the DTS mean that effective capacity trading and hub services arrangements are unlikely to be practically achieved and so a system of physical hubs and contract carriage is not appropriate in Victoria. In particular, the multitude of entry and exit points and need to flow gas across the entire DTS, mean that it is likely to be efficient for a hub operator to manage flows via a virtual hub and balance the system on behalf of participants.

In addition, the Commission's view is that implementing contract carriage as a package with physical trading hubs is not suited for the DTS due to the following practical challenges:

- Defining firm point-to-point rights on the DTS is likely to be practically difficult given the available capacity between any two points is significantly influenced by

109 In particular, in the event that an exchange counterparty defaults on part, or all, of its delivery quantity at the Wallumbilla GSH, they are required to compensate their counterparty for 25 per cent of the value of the variation. Importantly, this compensation is the only remedy available for a breach of a participant's delivery obligations and may under or over compensate a participant for their actual direct costs associated with the delivery default.

the expected pattern of injections, withdraws and flows across the entire network.

- Likely narrow imbalance tolerances and penalties would present a barrier to entry and involve large monitoring costs for shippers (metering and information systems).
- Variability of flows on the contract carriage 'spokes' is likely to result in the high cost Dandenong LNG facility being scheduled more frequently than currently to balance the inner ring.

Detail on the Southern Hub design is set out in the DWGM Review Draft Report that has been published concurrently with this report.[110]

5.2.1 Price discovery and balancing at the Southern Hub

The recommended Southern Hub market design is referred to as 'voluntary trading with market-based balancing' since participants are not forced to make daily bids and offers for gas injections and withdrawals, as per the current DWGM design and STTM hubs.

Instead, the Commission considers the Southern Hub should be designed so that participants can freely trade gas prior to the gas day on the market but:

- within the gas day, market participants are incentivised to balance their injections and withdrawals,[111] and are able to do this by trading actively on the market; and
- in the event that participants are not collectively balancing their injections and withdrawals, within an agreed tolerance, the hub operator can take actions to maintain the network within safe operational limits (a process known as '**residual balancing**'). The cost of residual balancing could be recovered from the participants that were out of balance.

A key benefit of transitioning the DWGM to a system of voluntary trading with market-based balancing is the expected emergence of a reference price that encourages the development of financial derivative products. Such a price allows parties to take equal but opposite positions in the spot and futures market, which will allow participants to effectively manage risk and therefore support growth in liquidity.

As noted in the Stage 1 Final Report, the majority of participants in the DWGM are effectively managing wholesale price risk by buying wholesale gas direct from upstream producers through bilateral contracts and selling to themselves through the DWGM. Once the Southern Hub becomes sufficiently liquid, we would expect these

110 AEMC 2015, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, December 2015, Sydney.

111 Note that participants would not be required to balance their injections with their withdrawals but instead their actual injections and withdrawals with their nominated injections and withdrawals.

contracts to transition from prices based on indices referencing oil or other products to referencing hub prices; or indeed a lower reliance on bilateral contracts generally as certainty about being able to access gas on the market grows.[112] Where long term contracts include hub referenced prices, parties would then seek to conduct financial risk management using derivatives linked to the reference price at the hub.

Similar to the Wallumbilla GSH, the Commission envisages that the exchange would publish an end of day, volume-weighted price. The purpose of doing so would be to provide the market a single price for gas that financial derivative products could reference. While we note that various price reporting agencies successfully report reference prices in other gas markets (typically based off an amalgam of both exchange trades and bilateral trades), these bodies provide a service in the commercial interests of gas market participants and their role in the Southern Hub will emerge over time if demanded by the market.

The establishment of exchange-based trading allows for innovation in products offered and for standardised products to emerge (eg, day-ahead products, monthly products, winter 2020 products etc) and participants will determine the success of individual products – that is, products will be traded only to the extent that they are useful to participants. In well-established commodity markets, financial derivatives generally reference the price in the most liquid of these products.

5.2.2 Allocation of pipeline capacity at the Southern Hub

The Commission recommends that the market carriage framework and associated limited transportation rights mechanisms (ie, AMDQ and AMDQ cc) be transitioned to an entry-exit system for capacity allocation. The current implicit allocation of transportation capacity based primarily on outcomes in the DWGM should be replaced with a new system that allows network users to book transportation capacity rights at each entry and exit point to the DTS and for these rights to be independent of one another.[113]

This supports the development of trading liquidity at the Southern Hub since gas can be traded irrespective of its physical location in the system. Moreover, demand for entry and/or exit capacity creates market-driven signals for investment in the system that currently does not occur.

The Commission's draft recommendations include the following features:

- An auction process would be used to allocate existing capacity, and potentially to trigger new capacity, at entry and exit points where there are multiple participants active. A market-based mechanism provides clear signals around the

112 This is the case in Western Europe where long term contracts negotiated are moving away from oil-indexed pricing to hubs.

113 Parties wishing to solely trade gas products at the Southern Hub prior to their delivery date (eg, financial traders) would not require entry and/or exit capacity so long as they close out there physical positions prior to delivery.

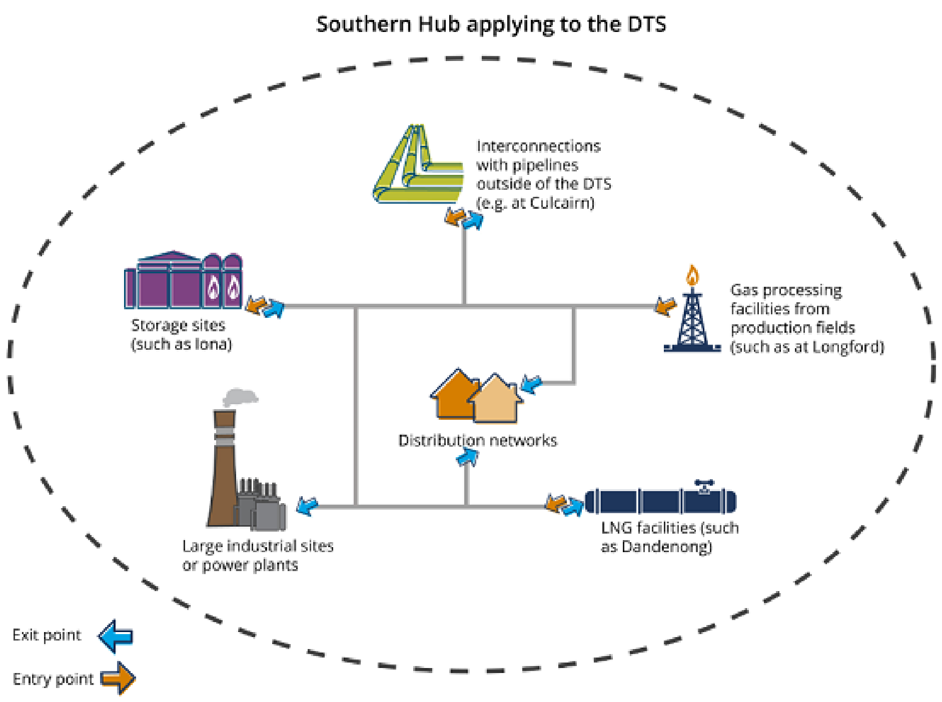
need for new capacity and so supports the provision of efficiently sized investment, delivered at the right location and when needed.

- At entry and exit points where there is only one active participant, capacity allocation would be administratively determined and a regulated access charge would apply. Where a participant requires additional capacity at one of these points (for example, to meet growing demand), a pre-commitment to pay the regulated charge for a number of years into the future would provide the trigger needed for new investment to occur.

Under an entry-exit system, the revenue earned by the pipeline owner would be regulated, on a similar basis (and at a similar level) to today. However, by allowing users to signal the need for additional investment in the DTS (including size and timing requirements), the risk of inefficient investment would be reduced. In addition, requiring users to purchase capacity (and to pre-commit to purchasing new capacity) at entry and exit points ensures they are the party that bears, at least some of, the costs (and risks) associated with their usage decisions. Allocating risk in this way creates incentives on users to ensure that their decisions on access (and hence the signals they create) are well informed and ultimately efficient.

Establishing a system of entry and exit rights in Victoria requires decisions to be made on the mechanism for booking transportation capacity to access the hub, the methodology for setting tariffs at entry and exit points and mechanisms, if required, to encourage secondary trading of capacity. Figure 5.1 shows a stylised depiction of an entry-exit framework over the DTS.

Figure 5.1 Stylised depiction of Southern Hub entry and exit points



More detail on the Commission’s draft recommendations for Victoria can be found in the Draft Report for the Review of the Victorian Declared Wholesale Gas Market.[114]

5.3 Northern Hub for trading gas

As discussed above, the Commission is of the view that the Energy Council's Vision would be best met by focussing trade at a Northern and Southern hub. Price discovery at both hubs would be via exchange-based continuous trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. Growth in trade and liquidity would be supported by a complementary package of pipeline access and market information reforms.

As part of the Wholesale Gas Markets Discussion Paper, the Commission tested three market design concepts. Two of these concepts included virtual hubs of varying sizes around Wallumbilla. One virtual hub covered Wallumbilla and the RBP, while the other covered all pipelines north of Moomba, excluding the MSP.

The Commission is conscious of providing the Energy Council with a solution that not only supports the Vision, but is proportionate to the issues at hand and clearly promotes the NGO. While implementing a larger virtual hub across a wider geographic footprint than the Wallumbilla facility could be expected to contribute to trading liquidity by concentrating a significant number of diverse buyers and sellers, further detailed work would need to be carried out before there was sufficient confidence that the costs and disruption of making such a significant change would outweigh the benefits.

The Commission is also conscious of, and supports, the work that AEMO has carried out in conjunction with industry as part of the design and implementation of the GSH at Wallumbilla. In this context, it is a more prudent approach to build on the existing GSH market design framework so that it has the best possible chance of promoting the Energy Council's Vision.

The Commission recommends that the Wallumbilla GSH be designated as the Northern Hub and that the market continues to evolve in the short term in line with AEMO's recommendations to the Energy Council. AEMO has recommended that the three pricing points at Wallumbilla be reduced to one through the Optional Hub Services model, as described in Box 5.3.

114 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2015, Sydney.

Box 5.3 Optional Hub Services model

At the time of approving the implementation of the Wallumbilla GSH, the Energy Council requested AEMO undertake a review of hub services to support the transition from three trading locations to one trading location. AEMO has completed this review and is recommending that the Energy Council approve implementation of a single Wallumbilla product through the Optional Hub Services model.[115]

The Optional Hub Services model would consolidate the three markets at Wallumbilla into one by pooling together trading participants operating on pipelines connecting to Wallumbilla. A default location within the Wallumbilla hub for the title transfer of gas would be defined in order to establish a single pricing point.

Hub services facilitate the delivery of transactions between trading participants operating on the different pipelines around the Wallumbilla hub. In essence, they facilitate the transfer of gas within a hub. Participants would manage the hub services required to transport their gas to the default trading location by using their own hub services or by purchasing a service from another shipper through the secondary market.

The Optional Hub Services model would establish a voluntary market for the trade of hub services by utilising the existing GSH exchange, enabling participants without existing access to hub services to exchange gas between facilities at Wallumbilla. The model aims to minimise the requirements for hub services through the netting and matching of delivery positions at Wallumbilla delivery points.

Over the longer term, the Commission's view is that the market may need to transition from a physical hub to a virtual hub in order to promote the Energy Council's Vision, although such a virtual hub might only cover the infrastructure located at Wallumbilla. This is because the design of the GSH model that has been implemented at Wallumbilla, and will soon be implemented at Moomba (see section 5.3.2), has the following drawbacks that may negatively impact liquidity growth:

- Lack of delivery certainty after trades have been matched on the exchange.
- Limited competition in the market for hub services.

Each of these is discussed in turn in the sections below.

Lack of delivery certainty after trades have been matched on the exchange

A drawback of the GSH market design that has been put forward to the Commission is the lack of delivery certainty after a trade has taken place on the exchange.[116] If a

115 AEMO, *Hub Services for a Single Wallumbilla Market, Draft Report*, October 2015.

116 CQ Partners, *Submission to the Stage 1 Draft Report*, p. 6.

counterparty fails to deliver the agreed volume of gas, there is no market-based balancing mechanism to deliver the gas that may be essential for the buyer to operate a factory, supply retail customers or run a gas-fired generator.

Compensation is required to be paid in the event that an exchange counterparty defaults on part, or all, of its delivery quantity, outside of the five per cent tolerance set by AEMO. If this occurs, participants are required to compensate their counterparty for 25 per cent of the value of the variation.[117] Importantly, this compensation is the only remedy available for a breach of a participant's delivery obligations and may under or over compensate a participant for their actual direct costs associated with the delivery default.

An example of how the compensatory mechanism works for delivery variance quantities outside of the tolerance range is illustrated in Box 5.4.

Box 5.4 Compensation for delivery quantity variances

Suppose that 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 is not able to deliver the entire contract quantity to Retailer X. 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 five 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 (ie the seller) is paid a total of $45,000 by Retailer X (ie the buyer) for the 8,000GJ 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.

Lack of delivery certainty is of particular concern to participants who do not have large portfolios of gas to call on in the event that a counterparty defaults on delivery. One of the positive features of the STTM hubs and DWGM put to the Commission by stakeholders was the certainty of delivery that these markets provide once a trade has

117 AEMO, *Detailed Design for a Gas Supply Hub at Wallumbilla*, 19 October 2012, p. 20.

been entered into.[118] This certainty is provided by the respective balancing mechanisms.

The Commission notes AEMO can suspend market participants from the GSH if the delivery variance quantity is equal to 25 per cent or more and such an event has occurred on three or more occasions on a rolling six month period, without any reasonable explanation.[119] However, for the Northern Hub to be an attractive market for all participants to trade at, and for trading liquidity to be maximised, the Commission considers that a market-based balancing mechanism is likely to be an aspect of the market that needs to be considered into the future.

Implementing a market-based balancing mechanism at Wallumbilla would necessitate the need for the GSH to transition from a physical to a virtual hub, consistent in design with the Commission's recommendations for the Southern Hub.

Potential limited competition in the market for hub services

The Commission understands that the primary hub services required to move gas across the Wallumbilla hub are compression and redirection. Compression allows participants to ship gas in a westerly direction from low-medium pressure headers to high pressure headers between pipelines at the hub. Compression may also be required to ship gas from the SWQP to the QGP depending on operational conditions. Redirection services allow participants to ship gas in the reverse direction through displacement of gas from a high pressure header to a low-medium pressure header.

A high portion of compression services at Wallumbilla are currently contracted to three major parties. Outside of long term bilateral contracting for new capacity, options for participants to procure access to compression to support short term trading at the hub include:

- the secondary market from the three primary shippers who hold compression capacity; or
- on an as-available basis from APA Group (the facility operator of most of the infrastructure at the Wallumbilla hub).

The Commission understands that re-direction services are primarily provided by APA Group as the facility operator.

As discussed in Chapter 4, a shipper with contracted pipeline capacity has an incentive to sell excess capacity prior to the nomination cut-off time, in order to recoup revenue that would otherwise be lost to that shipper. As the only seller of capacity beyond the nomination cut-off time, the facility operator has the ability and incentive to price as available capacity above levels expected in a workably competitive market. The Commission is concerned that high prices for such capacity, in combination with shippers' limited incentives to trade capacity, may result in inefficient outcomes.

118 CQ Partners, Submission to the Stage 1 Draft Report, p. 5.

119 AEMO, *Gas Supply Hub Exchange Agreement, version 3*, p. 65.

In instances where shippers simply forego the opportunity to sell capacity because it is not their core-business, a prospective shipper's alternative is to purchase as available capacity from the pipeline owner. However, high prices for this capacity may be pricing these shippers out of the market. This can be expected to have a negative impact on liquidity growth at the Northern Hub, as the number of potential trading opportunities is reduced.

The same set of issues is set out in Chapter 4 with regard to access to pipeline capacity to support hub trading also applies for hub services. If all physical gas market participants on the east coast are unable to access contracted but unused compression capacity to facilitate trading, then liquidity growth at the hub will be restricted.

If AEMO designates the default delivery location for the Optional Hub Services model at Wallumbilla as the SWQP high pressure header, this would mean that the seller is responsible for any hub service required to transfer gas to this location. As Table 5.1 shows, redirection and compression services are required from all major pipelines around Wallumbilla to flow gas to the default location.

Table 5.1 SWQP high pressure header notional point - hub service requirements

Pipeline	To default location	From default location
RBP	Redirection + Compression	-
BWP	Redirection + Compression	-
QGP	Redirection + Compression	Redirection
SWQP	Redirection + Compression	-
SGP	Redirection + Compression	NA
DDP	Redirection + Compression	NA

AEMO, *Hub Services for a Single Wallumbilla Market*, Draft Report, October 2015, p. 17.

The Commission recognises these issues and is recommending the following measures to help reduce transaction costs and promote the development of a workably competitive secondary market for pipeline capacity (as set out in Chapter 4):

1. the introduction of an auction for contracted but un-nominated capacity with an ex ante floor price on all pipelines; and

2. the mandatory creation of capacity trading platforms, through which information regarding all capacity trades would be published. Capacity product standardisation would facilitate trading through the platform.

Facility operators auctioning capacity on an as available basis would create a transparent market for pricing this service. Setting an ex ante floor price would protect potential shippers from outcomes inconsistent with a workably competitive market.

Setting a floor price also provides an additional incentive on shippers to sell any unused capacity, as the facility operator keeps the revenue from any capacity that is available to be auctioned.

While Chapter 4 makes reference to pipeline "capacity", the recommendations could equally apply to hub services. The Commission will give further consideration as to which additional services its recommendations should apply to in the Stage 2 Final Report.

5.3.1 Wallumbilla Single Trading Zone

The Commission notes the GSH model was implemented by AEMO at the request of the Energy Council prior to the Council outlining its Vision for Australia's future gas market. The market at Wallumbilla was predicated on a low cost, voluntary model with the objective of supporting improved wholesale trading of gas. AEMO's development work on the GSH model to date has continued within this context.

Going forward, and in order to promote the Vision, the Commission considers the Northern Hub may need to continue to evolve beyond implementation of Optional Hub Services. In order to provide participants with certainty of delivery and pricing of hub services, a transition to a virtual hub may be required.

In extremely liquid gas markets, delivery risk can be offset to a degree by the ability to purchase spot gas for delivery on the same day (ie balance-of-day products). If a sufficient level of trading liquidity does not develop at the Northern Hub for participants to have confidence that the market can provide this service, then it will likely be necessary to move to a model where a hub operator coordinates flows and balances the hub - that is transition from a physical to a virtual hub.

AEMO has begun work to develop one such approach - the Single Trading Zone model - as part of its advice to the Energy Council on hub services for a single Wallumbilla product. Box 5.5 provides an overview of this model, which would provide for a hub operator to manage and balance all flows at the hub, regardless of origin or destination.

Box 5.5 Single Trading Zone model

The Single Trading Zone model would group together delivery points on key facilities connecting at Wallumbilla to form a single market with all transactions and transit flows facilitated through a virtual trading point. A hub operator would manage all gas flows and balancing at the hub.[120]

The Single Trading Zone would have a mandatory participation framework that would apply to all flows transiting the Wallumbilla hub. As such, the framework would apply to exchange transactions, bilateral and OTC market transactions and to participants transiting gas through the hub. While the framework would apply to all gas flows, trading through the exchange would remain voluntary.

The inclusion of all flows is necessary to facilitate efficient operations and delivery of transactions at the hub. It would allow the hub operator to maximise opportunities to aggregate and net flows and to optimise gas flows and balancing. If participants were able to arbitrage between their own services and a hub operator provided service then it would be difficult for the hub operator to provide a fixed price and a firm service.

The following aspects of the market framework would likely apply to all Wallumbilla transactions under a Single Trading Zone model:

- All Wallumbilla transactions would be delivered at a virtual trading point.
- A hub operator would be responsible for the delivery of all transactions.
- All Wallumbilla flows would be subject to a market balancing arrangement - participants who are out of balance would be balanced by the hub operator and subject to any market balancing charges.

Advantages of the Single Trading Zone model

Development of a small virtual hub over Wallumbilla would enhance trading liquidity by enabling traders to bring gas to or receive gas from any point within the hub definition. Beyond nominating their intended delivery/receipt locations, participants would not be involved with the operational processes of managing gas flows or having to separately procure hub services to match trades. This would significantly simplify participation in the market.

The two issues identified under the Optional Hub Services model around certainty of delivery and access to competitively priced hub services (see section 5.3) would also be resolved. Under the Single Trading Zone model, certainty of delivery is provided through a market balancing arrangement, whereby participants who were out of balance would be balanced by the hub operator as a last resort. Standard tariffs would

120 AEMO, *Hub Services for a Single Wallumbilla Market, Draft Report*, October 2015.

apply for hub services for trading gas at the hub, as well as transiting gas through the hub, mitigating the ability of parties to price hub services on an anti-competitive basis.

By resolving the issues around certainty of delivery and access to hub services at Wallumbilla, and supported by a complementary package of pipeline access and market information reforms, the Single Trading Zone model would be likely to deliver a meaningful reference price for gas in the north. Under this approach, smaller shippers would be able to compete on an equal basis with large incumbents.

Over time, the outcome is likely to be a liquid hub where participants have confidence that the observed price reflects underlying supply and demand conditions. This will in turn encourage financial players to participate, as they will be confident that the liquidity exists to close out positions taken in the market prior to having to deliver or take delivery of gas. They will also be confident that the risk profile of their positions is consistent with that of a workably competitive market, where the actions of a small number of participants cannot undermine the price signal.

Areas for further development

As noted by AEMO, the Single Trading Zone model has to date been developed at a high level and is only one potential design option. Further detail and assessment of the regulatory and commercial options, as well as costs and benefits, needs to be undertaken before a decision to implement can be undertaken.

Of particular importance are the arrangements for accessing the hub by shippers and for cost recovery by the infrastructure owner. To-date, we understand that the design envisages all shippers paying a smeared charge to fund the costs of operating the hub. Such an approach would not give any long term investment signals to the hub operator/infrastructure owner, meaning that investments would have to be made based on forecast usage, with significant effects on risk allocation. It may be appropriate to consider the potential for shippers to enter into long term contracts for use of the hub, in a similar manner to the use of entry-exit rights under the recommended Southern Hub arrangements. Other issues for further consideration are the governance arrangements and role of the hub operator, as well as the treatment of existing property rights in the transition to the new regime.

Consistent with the Commission's recommendation of a common market design for the Northern and Southern Hubs, where possible, in order to minimise transaction costs and complexity for market participants, consideration should be given to how much harmonisation can be achieved. While exchange-based trading will be familiar across both hubs, if the Northern Hub were to evolve into a small virtual hub, it would be beneficial to develop the balancing and capacity allocation mechanisms as consistently as possible with the Southern Hub.

The Commission intends to continue working to develop the Single Trading Zone model with AEMO in the event it becomes clear that this approach will need to be implemented to achieve the Energy Council's Vision. An assessment of whether a Single Trading Zone at Wallumbilla - or any other form of virtual hub in south-east and/or south-west Queensland - is required will occur as part of phase two and three of the indicative implementation plan, a set out in section 5.5 and Chapter 7.

5.3.2 Moomba GSH trading location

AEMO has announced that it will be implementing a GSH at Moomba by 1 June 2016 and that this will extend the GSH model implemented at Wallumbilla.[121]

The Commission can see the short term attractiveness of continuing to implement additional GSH locations at pipeline junctions across the east coast, such as providing a relatively inexpensive platform for participants without pipeline access to trade on an ad-hoc basis. However, we do not necessarily see this as a long term solution for promoting the Energy Council's Vision.

As discussed above, the Commission sees a risk in spreading the limited trading on the east coast too thinly. Without most participants trading at a common location, there is unlikely to be the liquidity required to support a meaningful reference price and to provide participants with the confidence to use the markets regularly. Without confidence in the physical market, players without physical positions - such as financial institutions - are unlikely to participate due to the risk of not being able to close out their trades.[122]

Without financial players in the market, the number of institutions trading will naturally be limited and is likely to cap the growth in trading liquidity. Again, without a liquid physical market participants will not have the confidence in the market price to write financial derivatives over the physical products. This in turn limits the ability for players to hedge risk in the physical market and, in turn, negatively impacts liquidity.

It is clear to the Commission that a liquid physical gas market requires a concentration of physical and financial participants willing to trade regularly. Implementing additional GSH locations across the pipeline network may be low cost on face value. However, the substantial costs are those related to participants not having access to an additional source of gas procured through a market that they can use reliably and trust. This will eventually have a flow on impact to price paid by all consumers of gas, large and small.

In the United States, having many physical hubs across the network has been a successful model due to the large number of trading market participants - larger than any other country. Markets at individual physical hubs grow and contract in the United States depending on their level of use over time. This is unlikely to be a realistic approach in Australia, where the market is much more concentrated. If no individual trading point on the east coast emerges to become the benchmark hub, then the benefits of a liquid wholesale gas market will not flow through to consumers.

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121 AEMO, *Gas Supply Hub Reference Group Paper 29, Moomba Trading Location Implementation Plan.*

122 Financial players seek to close out their trades on the physical market prior to delivery as they generally do not have the capacity to deliver or receive gas.

While not explicitly part of the Commission's roadmap for a Northern Hub, a second GSH at Moomba is likely be an appropriate transitional measure to provide participants with flexibility until trading at the Northern and Southern hubs, and in capacity, matures and becomes liquid.

Over time, Moomba could establish itself as a transit point for gas flowing between the northern, eastern and southern markets, particularly with a pipeline soon to be built connecting the Northern Territory with the east coast market. On 17 November 2015, the Northern Territory Government announced that Jemena was selected as the preferred tenderer to construct a 622 kilometre pipeline from Tennant Creek to Mt Isa, as shown in Figure 5.2. The pipeline is expected to be operational by 2018.[123]

As discussed above, a drawback to the current GSH design is the lack of delivery certainty after a trade has taken place on the exchange. If a counterparty fails to deliver the agreed volume of gas, there is no market-based balancing mechanism to deliver the gas that may be essential for the buyer to operate a factory, supply retail customers or run a gas-fired generator. This is likely to restrict the ability of some participants to trade in the market.

Figure 5.2 Proposed NT Pipeline

Source: AEMC, derived from: http://dcm.nt.gov.au/territory_economy/north_east_gas_interconnector

123 Northern Territory Government Newsroom, *NT announces Jemena to build gas pipeline to east coast*, 17 November 2015. See http://newsroom.nt.gov.au/mediaRelease/16962.

5.4 Short Term Trading Market hubs

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.

The STTM provides flexibility to new entrant retailers and large industrial users of gas, who can choose to purchase some or all of their gas requirements through the market instead of directly from producers or retailers. This optionality lowers barriers to entry and promotes competition, creating benefits for consumers.

A key feature of the STTM hubs that make the markets attractive for participants is the certainty of delivery provided through the balancing mechanism. This is a key point of difference with the GSH design where, if a seller of gas fails to deliver the agreed volumes, the buyer has limited options to make up the difference at short notice. In the STTM hubs, this gas is provided through Market Operator Service.

While the STTM hubs have served their purpose well to date, the Commission notes that growth in trading activity at STTM hubs will be naturally limited due to their physical locations at the end of long transmission pipelines, which restricts the ability of participants to purchase STTM gas and ship it to other markets easily due to the cost of transport and/or the predominant flow of pipelines.

As a consequence, it is unlikely that the STTM will grow to include the level of trading activity required to develop into an efficient and credible reference price that participants can price contracts off and trade large volumes of gas around, as set out in the Energy Council's Vision.

Feedback from some stakeholders through the Commission's Stage 1 Report indicates that the level of complexity and costs of operating in the STTM may impose a disproportionate administrative burden on the market, relative to the role played by the STTM on the east coast.[124] Part of this issue stems from the fact that those participants who trade within their bilateral contracts incur a cost for participating in the market, irrespective of whether they derive any value from the arrangements.

The STTM hubs also represents an added level of complexity for entities wishing to operate across jurisdictions, as they are characterised by a different set of arrangements to the DWGM in Victoria, including gas day start times, although the roles of each market are similar.

5.4.1 Evolution of the STTM

As part of the road map for gas market development that the Commission is recommending to the Energy Council, participants would carry out the majority of

124 AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 1 Final Report*, 23 July 2015, Sydney, p. 112.

their trading at the Northern and Southern Hub, supported by changes to the pipeline access arrangements and accuracy and timeliness of information provision.

Once the Northern and Southern Hub are sufficiently mature and liquidity has developed in pipeline capacity trading, the Commission considers that the STTM hubs should be simplified to reduce transaction costs for participants. In continuing to evolve the STTM model, it will be important to preserve the key attributes supported by market participants, such as:

- transparent, market-based balancing to support a competitive retail market;
- certainty of delivery of supply; and
- provision of information to aid decision making.

AEMO's submission to the Wholesale Gas Markets Discussion Paper sets out a conceptual design of a simplified STTM that meets these requirements.[125] Under this high level design, the following changes would be made to the market:

- Replace the ex ante and ex post pricing mechanisms with a trade schedule where participants register transactions with AEMO. These could range from imbalance trades, on-the-day and day-ahead trades through to longer-term GSAs.
- Transactions would be carried out at the Northern and/or Southern Hub, with gas then transported to the demand hub, or bilaterally for delivery at the demand hub.
- A variation of the current Market Operator Service would be maintained to provide a competitive and transparent balancing mechanism at the hubs.
- Balancing costs paid for by participants that deviate from their trade schedule.
- Reporting, settlement and prudential services provided by the Market Operator.

While the ex ante and ex post pricing mechanisms would be removed, the Commission's considers it important that the balancing price for gas be published at the demand hubs on a daily basis, as this will facilitate transparency around balancing costs faced by market participants.

Evolving the STTM in this way would result in participants not having to submit price quantity pairs on a daily basis to ensure their gas is scheduled by the market. Additionally, AEMO would no longer be required to maintain systems to calculate provisional, ex ante or ex post prices. The Commission considers that much of the complexity and costs associated with the market design can be removed, while maintaining the core functionality participants will require in the context of the new market framework.

125 AEMO, *Submission to Wholesale Gas Markets Discussion Paper*, p. 5.

Under the recommended market framework, the Commission envisages most trading to occur at the Northern and Southern hubs as this will be where liquidity is high and transaction costs lowest. Over time, it will also be at these markets where financial derivatives will emerge to manage price risk. Improvements to the accuracy and timeliness of information provision, as well as access to pipeline capacity, will support exchange-based and bilateral trading at these locations.

Box 5.6 provides an example of how a large user could purchase gas from either the Northern or Southern hub to be consumed in Adelaide.

Box 5.6 Buying gas for consumption in Adelaide

Under the current arrangements, small volumes of gas are traded on the STTM hubs at the major demand centres across the east coast. While this provides participants with a convenient means of purchasing or selling incremental gas, it splits trading liquidity and is therefore unlikely to produce a reference price for gas that participants have confidence in and against which risk management products could be based on.

To foster a wholesale reference price for gas on the east coast, the Commission has recommended concentrating trading at a Northern and Southern Hub, supported by changes to encourage development of liquid market for pipeline capacity trading. Under these arrangements, a large user looking to utilise a trading market to purchase gas could:

- Purchase a week-ahead product on the exchange at the Southern Hub for the delivery of gas over a seven day period; on a similar anonymous electronic exchange, purchase secondary pipeline capacity on the SEA Gas Pipeline directly from a shipper selling spare capacity to transport the gas to Adelaide over the next week.
- Purchase a day-ahead product on the exchange at the Northern Hub for delivery the following gas day; on the relevant pipeline capacity exchange, participate in a daily auction of as-available capacity on the SWQP and MAPS simultaneously, in order to secure capacity to ship the gas to Adelaide the following day.

After the transaction(s) is complete, the large user would notify AEMO (as the Adelaide hub operator) of any gas it was shipping to the hub and the amount of gas it expected to withdraw from the hub, the day before the gas day. If the user deviated from its schedules, balancing services would be required and the user would receive a payment if long gas or pay a charge if short gas.

Encouraging growth in liquidity and a meaningful reference price at the Northern and Southern hubs, along with reforms to pipeline access and information provision, will provide participants with greater flexibility for buying and selling gas than currently exists. Because of this, there will not be a strong requirement to trade at the demand centres and the benefits of retaining the STTM hubs as independent pricing points is likely to outweigh the costs.

The Commission recognises some gas users have come to rely on the STTM hubs in recent times as a source of competitive gas supply that is critical to the ongoing operation of their businesses.[126]

Before transitioning the STTM hubs to pure balancing markets, the Commission will need to be satisfied that liquidity at the Northern and Southern hubs, and in pipeline capacity trading, has sufficiently developed to provide the same, if not more, flexibility to participants that the STTMs provide. As discussed in section 5.3.1, this may require moving the Wallumbilla GSH to a virtual hub with a hub operator managing flows and balancing the hub.

For this reason, simplification of the STTM hubs has been earmarked as one of the final aspects of the market development package, as set out in Chapter 7.

5.5 Summary of recommendations and staging

To summarise the Commission recommendations regarding trading markets, we are proposing:

- Two primary trading hubs on the east coast, one in the north and one in the south, with common trading mechanisms.
- The Northern Hub to consist of a physical hub at Wallumbilla, with the potential for a virtual hub at a later date.
- The Southern Hub to consist of a virtual hub covering the Victorian DTS, with an entry-exit regime for allocating capacity.
- Simplification of the STTM hubs to pure balancing markets once liquidity has developed at the Northern and Southern hubs and in pipeline capacity trading.

The Commission considers this number, location and type of trading markets will promote the NGO, support the Energy Council's Vision and be resilient in the face of a changing market. Potential uncertainties into the future include the impact that climate policies could have on the demand for gas-fired generation and continued development of unconventional gas resources.

The Commission's recommendations provide for a gas market framework that supports participants who wish to trade in the north through a primary hub at Wallumbilla and a secondary hub at Moomba. These locations are close to conventional and unconventional gas fields, storage facilities, gas-fired generators, LNG plants and a range of other gas users. The Southern Hub location facilitates the development of a liquid hub for participants from Sydney to Adelaide and in Victoria.

126 Wholesale Gas Markets Discussion Paper submissions: Visy, pp. 4-5; and Qenos, pp. 2-4. Stage 1 Draft Report submissions: Australian Paper, pp. 2-3; and CQ Partners, pp. 1-3.

Reforms to pipeline access will allow participants to move gas in and out of the hub locations in a more seamless manner than is currently possible and on a non-discriminatory basis.

The Commission considers that this type of hub arrangement will have the best chance of developing into a liquid market with a meaningful reference price for gas from which financial derivatives can be developed. To-date, while there have been a number of gas derivative products available for participants to use, the underlying physical markets have not been sufficiently liquid or designed in such a way to support the use of these products. By concentrating liquidity at two points on the east coast, and moving to exchange-based trading, the Commission envisages that financial derivatives will develop over time, along with the associated benefits, if warranted by industry.

Once sufficient liquidity has developed at these hubs and in the secondary pipeline capacity market, the STTM hubs can simplified so as to lower transaction costs for participants directly, as well as indirectly through an expected reduction in fees AEMO will be required to levy from participants to operate the current market designs.

Further detail on the Commission's recommended road map for gas market development is set out in Chapter 7.

5.5.1 Monitoring growth in market liquidity

In putting together its recommendations, the Commission is mindful of ensuring there is a robust case for change, as has been set out in Chapter 2, and that a set of 'markers' has been established to understand how success should be measured.

The Commission's view is that success will be achieved once a liquid wholesale gas market has developed, as per the Energy Council's Vision. The challenge is defining what 'liquid' means. In a qualitative sense, a liquid gas market was defined in the Wholesale Gas Markets Discussion Paper:[127]

- **market depth**: where no one single buyer or seller order is likely to move the market price;
- **market breadth**: where a large number of bids to purchase gas and offers to sell gas are present in the market;
- **immediacy**: the ability to trade large volumes of gas in a short period of time; and
- **resilience**: the ability of the market to recover towards its natural equilibrium after being exposed to a shock.

127 AEMC 2015, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, Wholesale Gas Markets Discussion Paper*, 6 August 2015, Sydney, p. 4

The Commission considers that a liquid physical and financial wholesale gas market, with a meaningful reference price for gas, has the potential to promote the NGO and bring substantial benefits in the long term interests of consumers. As the Commission's recommendations are implemented, it is therefore appropriate to monitor how liquidity is growing in the market and the response of participants. To do this, a number of quantitative measures need to be developed.

While there is no commonly accepted manner within which liquidity can be measured, a number of metrics have been developed as a tool by the Agency for the Cooperation of Energy Regulators (ACER) to monitor the development of the European wholesale gas markets.[128] These were summarised in the Wholesale Gas Markets Discussion Paper and include measures such as: order book volume, bid-offer spread, order book price sensitivity and number of trades.[129]

The Commission notes that the ACER metrics have been developed in the European gas market context where exchange-based trading has been in place for a number of years. As exchange-based trading of gas has only been recently introduced at the Wallumbilla GSH, these metrics are unlikely to be fit-for-purpose in the short to medium term. Once the Commission's recommendations have been implemented for a number of years, the ACER framework may provide a useful tool for monitoring the health of the Northern and Southern hubs, as well as Moomba.

In the more immediate future, the Commission has put together four key liquidity measures that could be used as a way of monitoring how quickly the Northern and Southern Hubs are developing. These are set out in Table 5.2.[130]

The first measure is designed to monitor the **level of participation** at the Northern and Southern hubs relative to the number of physical participants in the east coast gas market. This is important as it provides a snapshot of how well supported the hubs are by both *physical* and *financial* players. A ratio below 100 per cent may indicate that not all physical participants are actively trading at the hubs, while a ratio above 100 per cent provides an indication that most or all physical participants are likely trading, along with a number of financial market players.

Price relevance threshold measures the number of trades required per product at each hub on any given day to provide confidence that the price signal is meaningful. The threshold for this metric is 15 trades per product per day and is based on a survey of European market participants who were asked what the minimum number of trades would be in their view for the price to be trustworthy.

Liquidity threshold measures the amount of gas that is simultaneously being offered and requested for each product at a hub so that the product is considered "liquid". Put another way, this metric is measuring the total volume of gas on the supply and

128 ACER, *European Gas Target Model review and update*, January 2015.

129 AEMC 2015, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, Wholesale Gas Markets Discussion Paper*, 6 August 2015, Sydney, pp. 12-13.

130 Measures are based on work by Wagner, Elbling & Company for ACER in 2014.

demand side for each product at a hub. The proposed liquidity requirement is 10,000 GJ based on a survey of European gas market participants.

The last measure is **liquidity trading horizon**, which provides an indication as to which products it is possible to trade into the future. While the European survey of market participants suggested 36 months was the requirement for a market to be deemed as "liquid", the Commission is of the view that this timeframe is too ambitious for the Australian context. The Commission proposes 12 months as a realistic goal to aim for in the medium term.

While not discussed specifically in this section, the Commission notes that it would be useful to apply a set of similar measures to those in Table 5.2 to the pipeline capacity trading and hub services markets, in order to monitor the their development.

As part of the consultation process for this Draft Report, the Commission is seeking feedback from participants on the quantitative liquidity measures set out below.

Table 5.2 Measures of gas market and pipeline capacity trading liquidity

Measure	Description	Liquidity requirement
Ratio of market participants actively trading at the hubs to physical players on the east coast	Measures level of participation at the exchanges relative to physical participants in the gas market	≥100%
Price relevance threshold	Number of trades required per product/hub/pipeline/trading-day so that the price signal can be considered trustworthy	≥15 trades
Liquidity threshold	Amount of gas simultaneously offered/requested (ask/bid) for a product on a hub so that the product is considered “liquid”	≥10,000 GJ
Liquidity trading horizon	Time horizon within which trading in gas products should be possible with the market being in a liquid state	≥12 months

6 Information and the Bulletin Board

Box 6.1 Summary of recommendations

To support its recommended approach to the evolution of gas trading hubs on the east coast, the Commission has also developed a detailed package of draft recommendations to enhance the information provided to the market.

An important characteristic of a workably competitive market is that participants have ready access to the information they require to make informed decisions about the prices they expect to see resulting from that market. In gas markets, such pricing expectations are not formed in relation to one specific data point but require a range of information about production and consumption levels, transportation flows, and investment levels in both the short and long run.

A central repository of information for use by all market participants and the public exists in the form of the Natural Gas Services Bulletin Board. However, the Commission has identified that there are some gaps and asymmetries in information provision that may be affecting the efficiency with which gas and other resources are allocated in the market and across the economy.

To address these issues, the Commission is making draft recommendations to improve information transparency through the following developments to the Bulletin Board and its governance:

- The stated purpose of the Bulletin Board in the NGR should be broadened to reflect the wider role that information plays in the sector.
- The coverage of the Bulletin Board should be expanded so that a wider range of information is provided through it.
- The reporting framework in the NGR should be improved to allow all relevant facilities to be reported, and in a timely manner.
- The compliance framework should be strengthened by classifying the obligation to register as a civil penalty provision in the Regulations.
- The governance of the Bulletin Board's funding arrangements should be harmonised with that for other AEMO functions.
- A regular review process to maintain the relevance of the Bulletin Board and the information reported on it should be introduced.

To implement these recommendations will require changes to be made to the NGL, NGR and Regulations, as well as to the Bulletin Board Procedures. The Commission will be in a position by the Stage 2 Final Report to make detailed and specific recommendations capable of immediate progression.

6.1 Introduction

An important characteristic of a workably competitive market is that participants have ready access to the information they require to make informed decisions about the prices they expect to see resulting from that market. In gas markets, such pricing expectations are not formed in relation to one specific data point but require a range of information about production and consumption levels, transportation flows, and investment levels 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 both in the market and the broader economy.

The east coast gas market has historically operated in quite an opaque manner with gas, transportation and risk management services sold under bilateral contracts that have invariably been treated as confidential by the parties. Information on some key demand and supply fundamentals in the market has also tended to be opaque.

In response, the Bulletin Board was created in mid-2008 to provide a more level playing field by requiring information be provided to a central repository for use by all market participants and the public.

With the gas market becoming more dynamic, timely and accurate information to inform operational and commercial decisions, as well as policy decisions, is becoming more important. Information will support gas use and allocation decisions over the short and long term, leading to the efficient use of and investment in gas for the long term interests of consumers – consistent with the NGO. However, the Stage 1 Final Report of the East Coast Gas Review noted that there are "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".[131] For this reason, Stage 2 of the East Coast Gas Review has focussed on potential improvements to the Bulletin Board, in particular with the aim of establishing it as a 'one-stop-shop' for information on the east coast gas market.[132]

As a result, in addition to the recommended information provision requirements discussed with regard to pipeline capacity trades (see chapter 4), the Commission is recommending further improvements to information transparency through developments to the Bulletin Board. The remainder of this chapter sets out, at a high level, the draft recommendations with regard to:

- the purpose and content of the Bulletin Board;
- the reporting and compliance frameworks that underpin the Bulletin Board; and
- funding arrangements and future developments.

131 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 1 Final Report*, 23 July 2015, p. 159.

132 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, p. 176.

A separate report on information provision and the Bulletin Board accompanies this Draft Report and can be found on the Commission's website.[133] This report provides a more detailed explanation and assessment of the Commission's recommendations, a collation of the draft recommended NGL and NGR changes, and specific issues to which stakeholders are invited to address in their submissions.

6.2 Purpose and content of the Bulletin Board

Stakeholders and the COAG Energy Council have noted that there are a number of significant information gaps and asymmetries across the gas sector. These gaps can be expected to adversely affect the price discovery process and the way in which gas and other resources are allocated because trading and other decisions must be made on the basis of incomplete, inaccurate and/or asymmetric information.

To address the informational gaps and asymmetries, Commission's draft recommendations include the following improvements to the Bulletin Board:

- The stated purpose of the Bulletin Board in the NGR should be broadened to reflect the important role information plays in enabling informed and efficient decision making, as well as aiding price discovery and facilitating trade.
- The coverage of the Bulletin Board should be expanded to include, among other things, the following information:
  - Upstream activities: Proven and probable reserves should be published.
  - Hub services: The operators of compressors in a gas supply hub should generally be subject to the same reporting obligations as operators of pipelines.
  - Large users (including LNG proponents): Large user facilities that meet the minimum reporting threshold should be required to report the nameplate capacity of their facilities and daily consumption. LNG processing facilities should also be required to report on their facility's short and medium term capacity outlook and material intra-day changes in capacity.
- The frequency with which information is reported should be improved by requiring material changes to a facility's capacity during a gas day to be reported as soon as practicable. This information, with updates to pipeline nominations, should be displayed prominently on the Bulletin Board.

6.3 Bulletin Board reporting and compliance frameworks

The confidence of market participants in the information reported on the Bulletin Board will depend on the extent to which the reporting and compliance frameworks

133 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report: Information Provision, December 2015.

provide for an accurate and timely picture of gas supply, pipeline flows, storage and demand. The Commission's assessment is that some elements of these frameworks are limiting the reliance that can be placed on information reported on the Bulletin Board. In particular, the reporting framework does not currently capture all of the facilities it should and can result in delays in the registration of new facilities. The Commission also has concerns with the strength of the compliance framework and the fact that the reporting framework does not include a clear reporting standard.

To address these concerns and instil a greater level of confidence in the Bulletin Board, the Commission's draft recommendations are that:

- The reporting framework in the NGR should be improved by:
  - removing the link between the obligation to report and the zonal model;
  - no longer mandating the use of the zonal model to aggregate pipeline flow data and giving AEMO greater flexibility to determine how this information is aggregated through the Procedures;
  - replacing the exemption criteria with a minimum reporting threshold (which will be reduced from 20 TJ/day to 10 TJ/day) and removing the distinction that currently exists between facilities commissioned pre- and post-1 July 2008; and
  - redrafting the registration provisions and introducing a reporting standard.
- The compliance framework should be strengthened by classifying the obligation to register as a civil penalty provision in the Regulations. Notes should also be added to the relevant areas of Part 18 of the NGR to identify those provisions that are civil penalty provisions.

6.4 Funding arrangements and future developments

Currently, the cost recovery mechanism for Bulletin Board participants is limited to pipeline operators for the provision of 'aggregation and information services' to AEMO. Some stakeholders have called for these cost recovery rules to be applied more broadly to all parties that provide any information to AEMO for the Bulletin Board. However, as a result of some of the other draft recommendations:

- pipeline operators would no longer provide all the current 'aggregation and information services'; and
- the burden of providing information would increasingly be shared by more gas market participants.

As a result, the Commission's draft recommendation is that the market participant cost recovery provisions be removed from the NGR.

The NGR currently sets out the methodology that AEMO is to employ to recover its Bulletin Board costs. However, this provides a governance framework that is inconsistent with those in place for other AEMO activities. In addition, the level of prescription in the NGR has resulted in very little flexibility for AEMO to adjust its methodology to changing market circumstances. The Commission considers that the inconsistent governance approach is unwarranted and that AEMO should be able to incorporate its Bulletin Board costs into its broader fee methodology process. Accordingly, the Commission's draft recommendation is that the current rules on the cost recovery of AEMO's Bulletin Board activities should be removed from the NGR.

A key factor leading to our work in this area, was a concern that the Bulletin Board has had limited amendments made to maintain its relevance to the east coast gas market and to meet the needs of market participants. The Commission acknowledges this concern and to provide a framework to assist in the ongoing improvement of the Bulletin Board has set out draft recommendations that AEMO:

- be provided with clearer and more direct responsibility to maintain the relevance of the Bulletin Board over time by requiring it to 'update' the Bulletin Board; and
- publish a biennial report on the Bulletin Board, including relevant information such as a summary of the Bulletin Board work program, performance and usage statistics, compliance and enforcement activities and also identifying any aspects that potentially require amendment. The report is to be prepared in consultation with market participants, Bulletin Board users and the AER and AEMC. It will aid in the identification of minor issues and potential procedure changes as well as potential rule change requests or more substantial concerns that may be considered by the COAG Energy Council.

6.5 Implementation

The package of draft recommendations include changes to the current operation of the Bulletin Board as well as required amendments to the National Gas Law (NGL), National Gas Rules (NGR), National Gas (SA) Regulations (Regulations) and Bulletin Board Procedures (Procedures). The separate report which accompanies this paper provides details of the required changes.[134]

This implementation phase is not contingent upon other recommendations in the East Coast Gas Review or the recommendations in the DWGM Review. In addition, given the more detailed and advanced nature of this work, the Commission will be in a position by the Stage 2 Final Report to make specific recommendations for implementation, capable of immediate progression. Accordingly, the amendment processes will be able to commence shortly after the publication of the final report.

134 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report: Information Provision, December 2015.

7 Implementation and next steps

7.1 A comprehensive package of reforms

The Commission's draft recommendations for the East Coast and Victorian DWGM reviews form a package of integrated reforms, developed with regard to the Energy Council's Vision and Gas Market Development Plan. As outlined over the preceding chapters, the Commission recommends the following direction for the development of the gas trading markets on the east coast:

- Two primary trading hubs on the east coast, one in the north and one in the south, with exchange-based trading applying to each.
- The Southern Hub to consist of a virtual hub covering the Victorian DTS, with an entry-exit regime for allocating capacity.
- The Northern Hub to be initially defined as a physical hub at Wallumbilla, with the potential for a virtual hub at a later date.[135]
- Simplification of the STTM hubs to pure balancing markets once liquidity has developed at the Northern and Southern hubs, and in pipeline capacity trading.

While not explicitly part of the Northern Hub, the Commission considers that a second GSH at Moomba is likely to be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba may establish itself as a transit point for gas flowing between the northern and eastern gas markets, particularly given the recent announcement to connect the northern and eastern gas markets via a new pipeline (see section 5.3.2).

As set out in Chapters 4 and 6, development of the Northern and Southern hubs is supported by equally important recommendations to enhance pipeline access and information provision. In this respect, the package developed by the Commission is a set of inter-related recommendations that mutually reinforce the objectives of each other. Together, the proposed reforms aim to support three key outcomes:

- Establishment of an efficient and transparent reference price for gas.
- Participants being able to readily trade gas between hub locations.
- Investment in infrastructure that responds to market signals and is facilitated by a supportive regulatory framework.

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135 The incremental development of the existing Wallumbilla GSH, including the introduction of optional hub services, may be sufficient to develop a liquid trading hub in the north, particularly if a liquid market for pipeline capacity develops. However, in the event that this does not occur, it may be necessary to transition to a single trading zone or a larger virtual hub similar to the Southern Hub in Victoria.

Once in place, these reforms 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.

7.2 A staged approach to implementation

The scope of the reform program will require leadership by the COAG Energy Council in implementing the agreed changes to the market and regulatory arrangements. The reforms should be implemented in a timely manner, but with recognition of the need for a detailed design phase and a clear and comprehensive transition and implementation strategy.

While the Commission considers that many of its recommendations should be implemented as soon as possible, others will need to be implemented in sequence. Some further measures being considered by the Commission will be contingent on the relative success (or otherwise) of the earlier recommendations. In this way, the Commission envisages that the implementation of the complete package will occur over several phases, forming a roadmap to guide the development of the market over the next decade.

The Commission's current view is that the first phase of reform, to be completed within the next five years, would comprise:

- Implementing the recommended enhancements to information provided through the Bulletin Board. The Commission will be in a position by the final report to make detailed and specific recommendations as to the amendments to the NGL, NGR, Regulations and Bulletin Board Procedures that will be required, and these will be capable of immediate progression.

- Introducing the recommended mechanisms outlined in Chapter 4 to enhance pipeline access. The Commission's intention is that implementation would be primarily driven by industry, and so appropriate governance arrangements will need to be put in place to allow standardisation and the introduction of the capacity trading platform(s) to be implemented. Some regulatory work, such as developing the reserve price methodology, will also need to be undertaken in parallel.

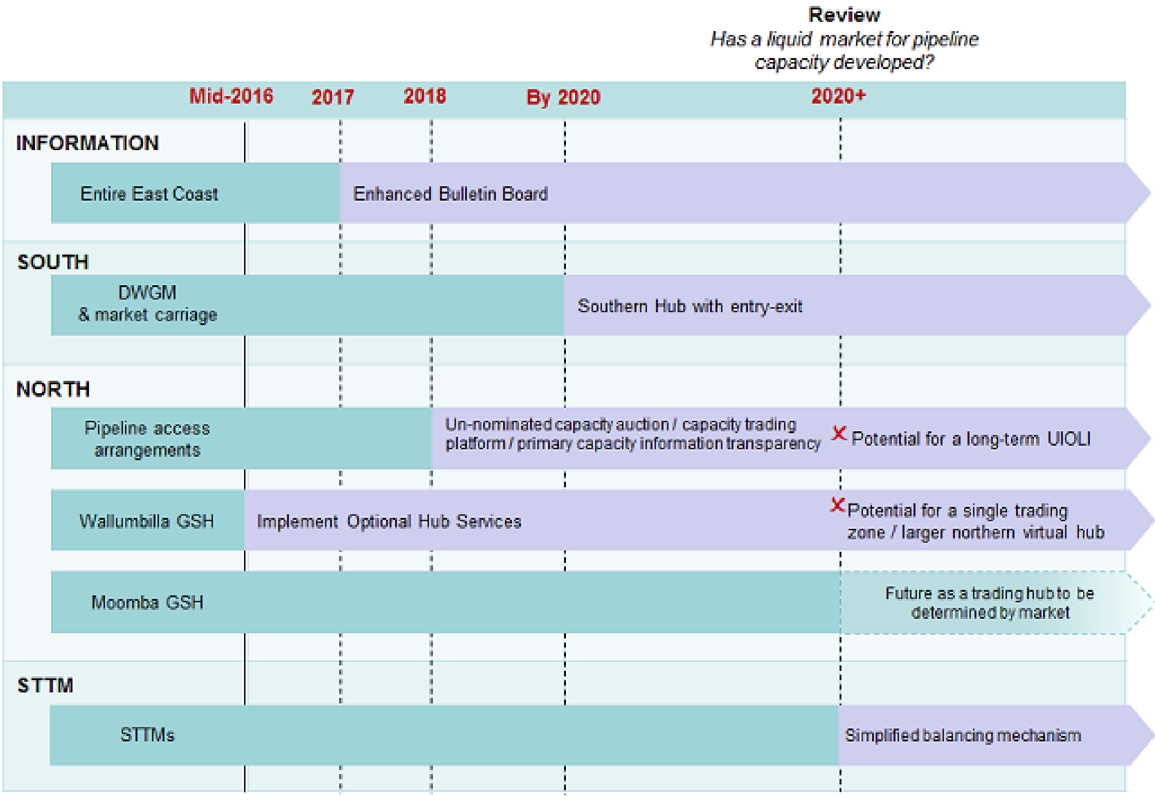
- Transitioning the DWGM and market carriage arrangements to the recommended Southern Hub design, including a complementary system of entry and exit rights. It is likely that further detailed design work be required to finalise these arrangements following this review, prior to implementation.

These measures would be in addition to the work currently being undertaken by AEMO to implement the Optional Hub Services arrangements at the Wallumbilla GSH and establish an additional GSH at Moomba.

An overview of the staging of the overall package is set out in Figure 7.1 below, which also highlights certain dependencies later in the reform program.

Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. If an effective market for pipeline capacity does not develop, then the pipeline access arrangement reforms may need to be coupled with a long term use-it-or-lose-it mechanism. Additionally, the Commission would look to potentially establish a single trading zone / larger northern virtual hub under these circumstances.

Figure 7.1 Reforming east coast gas markets



These key contingencies in the later phases of market development are as follows:

- If an effective market for pipeline capacity does not develop, then the pipeline access arrangement reforms may need to be coupled with a long term use-it-or-lose-it mechanism.
- Further development of the Wallumbilla GSH may also be warranted if trading in pipeline capacity and hub services is ineffective and does not support the development of liquid commodity trading. In addition, the Commission considers that there may be a need to implement a mandatory balancing mechanism, if the liquidity of trading is insufficient to give participants certainty of delivery.
- A second GSH at Moomba is likely to represent an appropriate transitional measure to provide participants with flexibility until trading at the Northern and Southern hubs, and in capacity, mature and become liquid. At that point, the

Commission would expect that the future (or otherwise) of Moomba as a trading hub would be determined by the market.

- Finally, once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the STTM hubs would be simplified from their current design to purely support transparent and competitive balancing.

7.3 Next steps

7.3.1 Further design work

Over the remainder of the review, the Commission intends to undertake further work to develop its recommendations in more detail.

The areas which the Commission anticipates considering further include:

- exchange-based trading and market-based balancing regimes;
- the entry-exit regime for the Southern Hub, including capacity allocation mechanisms and tariff methodologies;
- changes to the access arrangement for the DTS;
- the auction for contracted but un-nominated pipeline capacity;
- the pipeline capacity trading platform(s);
- appropriate capacity product standardisation, and the governance of an industry process to have carriage of this; and
- new roles and functions, and the identification of the appropriate institutions to take these roles.

7.3.2 Assessment

While transitioning to the Commission's recommended model will provide many benefits to market participants wishing to trade gas on the east coast and, in turn, consumers of gas, there will also be costs involved. These include the costs associated with implementation of exchanges and platforms to trade gas and pipeline capacity, integration with existing systems and operations, ongoing operational costs, and implementation and establishment costs for industry.

The Commission is undertaking further work to understand the costs and likely benefits of implementing the reforms proposed and will present these findings in our final report. Stakeholder views on how implementation might best be undertaken, if this model were recommended, are welcomed through this consultation process.

Some stakeholders have suggested that the benefits and costs of the market development package should be quantitatively estimated before implementation. The Commission agrees that it is important to assess the likely costs and benefits of potential reform with regard to the NGO.

However, analysing the likely costs and benefits of reform of this nature is inherently complex and in some cases is poorly suited to quantitative assessment – either because such assessment is not possible or because there is a large degree of uncertainty. In particular, it is often more straightforward to derive quantitative estimates of costs than of benefits, which tend to be more diffuse.

While the Commission will seek to develop quantitative measures where possible and relevant, any assessment against the NGO is likely to, in large part, draw on qualitative measures. The Commission considers such an approach to be appropriate and unavoidable.

7.3.3 Implementation

A key part of the Stage 2 Final Report will be a recommendation as to how the implementation of the Commission's reform package should be progressed.

While implementation of the Commission's recommendations on information provision will be capable of immediate progression through the rule change process (with a limited number of associated NGL changes), implementing the Commission's other recommendations will be considerably more complex. The high-level design developed by the Commission in this review will need to be given effect through:

- extensive, inter-linked changes to the NGL, NGR, regulations and procedures; and
- new business processes and systems across a range of institutions and market participants.

Over the remainder of the review, the Commission intends to undertake further work to develop its recommendations in more detail. This will include further consideration of how the implementation of the recommendations should be managed. The implementation process may include the formation of a dedicated team to lead and co-ordinate the various elements of the reform roadmap. There may potentially be a role for an advisory panel to provide stakeholder input.

We recognise that measures such as these would be likely to require a significant degree of commitment and cooperation from a range of stakeholders. However, we consider this to be appropriate given the nature of the likely task. At this stage, it appears unlikely that it would be efficient, or even possible, to implement the reform package in a piecemeal manner using existing 'business-as-usual' processes.

A 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 Australian 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 Assessment framework

The purpose of this appendix 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.

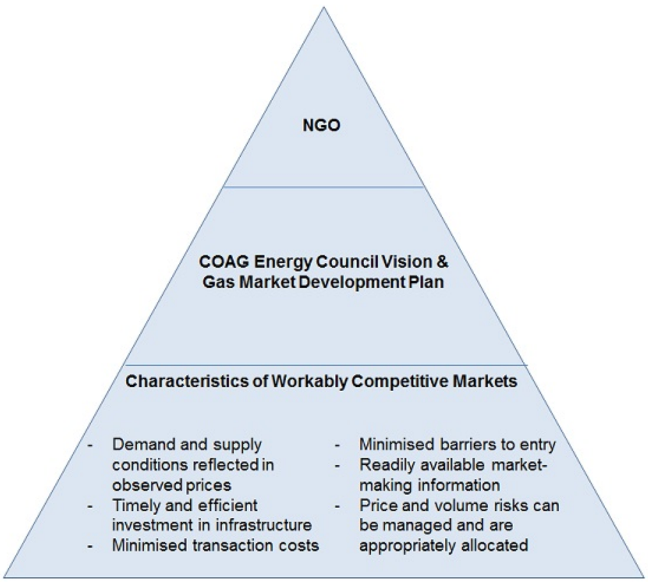
B.1 Assessment framework structure

In accordance with the terms of reference, the 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.

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 B.1, and each is discussed below.

Figure B.1 Assessment framework



B.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:[136]

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 imitate the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;

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

- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them; and
- 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.

These principles guide the direction of the recommendations stemming from these reviews towards achieving the NGO.

B.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference, the AEMC must also have regard to the Energy Council's Vision for Australia's future gas market and Gas Market Development Plan. Specifically, the Energy 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 Energy Council's Vision for Australia's future gas market, which is as follows:[137]

> "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:[138]

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.

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

138 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/

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 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.

B.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.[139] These are:[140]

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.

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139 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."

140 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.

C Submissions to the discussion papers

This appendix outlines a summary of submissions of the issues raised relating to the Wholesale Gas Markets Discussion Paper (August 2015) and Pipeline Regulation and Capacity Trading Discussion Paper (September 2015). It also sets out the AEMC's response to the issues raised. Note that where stakeholder views relate to the same issue, they have been grouped together in the table and responded to by the AEMC collectively.

Copies of submissions can be found on the AEMC's website.

Table C.1 Summary of submissions to Pipeline Regulation and Capacity Trading Discussion Paper

Issue raised	Stakeholder(s)	AEMC response
	General	
An issue or problem must be more clearly identified before proposing changes. The discussion paper only identifies potential 'obstacles' to the development of a liquid gas market.	Jemena, p.3; APGA, pp.3, 6; APA, pp.2, 6; Origin, p.1.	The Commission considers that there are issues in the capacity market that warrant regulatory change. See section 4.1.
The stated objectives of the review and the COAG Energy Council's vision appear to focus on short term, allocative efficiency (eg the efficient allocation of existing pipeline capacity), while the NGO focuses on long term efficiency (eg efficient investment in new pipeline capacity). The AEMC's subsequent assessment process should address the trade-off between these and clarify the long term objectives.	APA (Houston Kemp), pp.2-3.	See section 3.5 for a discussion of the Commission's assessment framework and an assessment of its recommendations with regard to the NGO.
It's not clear that transmission arrangements are contributing to low market liquidity. Low liquidity could be a result of the number of participants.	APA, p.26.	The Commission acknowledges that the lack of trade could be because the value placed on the capacity by its current holder is greater than the value placed on it by any potential buyer, in which case the capacity is held by the party which values it most highly – an efficient outcome. Put another way, the demand for secondary capacity could be low.

Issue raised	Stakeholder(s)	AEMC response
		However, the apparently low number of shorter term capacity transactions indicates that capacity may not be being allocated through commercial transactions to the party that values it the highest. See section 4.3.1.
Decisions should not be made until the ACCC Inquiry is released, as this would provide evidence of the nature of any issues.	Jemena, pp.3-4; APGA, p.5.	The Commission has worked closely to date with the ACCC, which has informed the Commission's draft recommendations. The Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. The Commission intends to publish its final report after the ACCC's Inquiry is finished. See section 4.1.
Significant reform should not be pursued while the market adjusts to the changes associated with LNG exports in Queensland.	AGL, p.1.	Future industry participants are likely to require more flexible and sophisticated ways of managing their gas portfolios because of upward pressure on GSA contract prices, reduced flexibility in GSAs and increased spot price volatility. See Chapter 2.
The existing framework has provided incentives for pipeline operators to provide services that meet the needs of all its users, including trading between users. Some pipelines, such as the Moomba to Adelaide Pipeline system, would not benefit from any of the approaches.	Epic Energy, p.4; Jemena, p.4.	The Commission will continue to consider the extent to which its recommendations should be designed to account for the variety of sector participants.
Some parties have not experienced high search and transaction costs for pipeline capacity trading.	Stanwell, p.2.	While recommendations to reduce transaction costs may not benefit all parties, the Commission considers that they are likely to be of overall market benefit, consistent with the NGO. See section 4.3.1.

Issue raised	Stakeholder(s)	AEMC response
Storage facilities, hub services and other pipeline services should be specifically included in the discussion of regulation and trading arrangements.	AEMO, p.1.	While Chapter 4 makes reference to pipeline "capacity", the recommendations could equally apply to hub and other services. The Commission will give further consideration as to which additional services its recommendations should apply to in the Stage 2 Final Report. See section 5.3 (Potential limited competition in the market for hub services).
Pipelines are characterised by economies of scale and are designed to serve variable demand. Therefore it is productively efficient that some capacity will remain unutilised. These attributes can be present in a workably competitive market. The AEMC should tease out these economic complexities in the subsequent review process.	APA (Houston Kemp), pp.6, 12.	The Commission is particularly concerned in cases when capacity is valued but unutilised. The apparently low number of shorter term capacity transactions indicates that capacity may not be being allocated through commercial transactions to the party that values it the highest. See section 4.3.1.
There should be a central trading platform for pipeline capacity.	AEMO, p.2; Esso, p.1; QGC, p.7; GDF SUEZ, p.3.	See section 4.3 which recommends a central trading platform for pipeline capacity.
Industry led responses are preferred. They are likely to be delivered faster and at lower cost than government initiatives or regulation.	APGA, p.3; APA, p.26; Santos, p.1.	Despite initiatives undertaken by industry to date, and other regulatory changes underway, the Commission considers that further regulatory changes are required to reduce search and transaction costs. See section 4.3.1. Consideration would need to be given to the process by which standardisation of capacity might occur. We note that in the US, an industry grouping (initially GISB (the Gas Industry Standards Board), now NAESB (the North American Energy Standards Board)) develops standards and protocols under FERC oversight. See section 4.3.3.
Regulatory intervention is necessary to address the issues raised in the discussion paper. The market would have addressed these issues already if it were possible.	MEU, p.13.	
Market power is not likely to be an issue where there are multiple sellers and buyers, access to low cost infrastructure (with non discriminatory tariffs) and a common gas specification (a fungible commodity).	Encana, p.6.	Recommendations made by the Commission and discussed in Chapter 4 seek to improve incentives for shippers to trade capacity, provide non-discriminatory access, provide access to contracted but un-nominated capacity at a price consistent with

Issue raised	Stakeholder(s)	AEMC response
Gas storage makes the market more resilient and flexible, but in Australia has been hindered by high transportation tariffs, including interruptible tariffs on pipelines that have surplus capacity.	Encana, pp.7-8.	that expected in a workably competitive market, and standardise capacity. The Commission is not at this stage recommending changes to the economic regulation of pipelines. The Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In light of the ACCC's findings, the Commission may supplement its draft recommendations with those concerning the economic regulation of pipelines.
Pipeline tariffs should be the same for anyone using the same type of service in the same location. Tariffs should also reflect depreciation of the pipeline (or the capital costs that have been recovered) and low cost expansions should be enjoyed by all users.	Encana, p.4.	
Pipeline owners that are not regulated or subject to competition protect their existing customers over new customers. They set tariffs at rates that the market can bear, instead of cost reflective tariffs. They build new facilities instead of offering services to improve efficiency.	Encana, pp.27-28.	
The discussion paper did not discuss Canada's gas experience, which has resembled Australia and is now a world leader in gas transport at low tariff rates.	Encana, p.31.	The Commission will continue to investigate relevant international experience.
A staged or incremental approach to implementing measures would reduce unnecessary costs on consumers. There should be sufficient time in between each stage to assess the effectiveness and whether further measures are necessary.	Jemena, p.8; ESAA, p.2; Origin, p.1; APLNG, p.2; Santos, p,2.	The Commission makes a number of recommendations regarding pipeline capacity markets in Chapter 4, which it considers should be implemented as soon as practicable. The Commission does not recommend the immediate introduction of a long term UIOLI mechanism. However, should the recommended auction for contracted but un-nominated capacity combined with improvements to facilitate secondary capacity trading (described in Chapter 4) result in insufficient levels of trade, then the Commission recommends that the introduction of a long term UIOLI mechanism should be re-considered. See section 4.3.5 and Chapter 7.

Issue raised	Stakeholder(s)	AEMC response
Aspects of all three approaches are needed to deliver an efficient gas transmission service.	MEU, p.24.	The Commission considers the recommendations to be a balanced and proportionate suite of reforms given the issues observed in the sector. They will provide market participants with an improved opportunity to trade capacity once they have improved incentives and ability to do so, supported by better information. The Commission also considers the suite of reforms to be internally consistent and self-reinforcing. See section 4.5.
Approach A - Facilitate trading between parties		
Approach A alone is unlikely to resolve pipeline congestion and utilisation as it does not address incentives on pipeline owners and shippers to trade unused, contracted pipeline capacity.	AEMO, p.1, QGC, p.7; MEU, p.20.	As noted above, the Commission considers the recommendations in Chapter 4 to be a balanced and proportionate suite of reforms given the issues observed in the sector. The Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In light of the ACCC's findings, the Commission may supplement its draft recommendations with those concerning the economic regulation of pipelines.
Further reform (Approaches B and C) should be considered now, as recent initiatives to facilitate trading of pipeline capacity have not been successful.	AEMO, p.1.	
This approach would be a starting point and should be implemented in the first instance.	QGC, p.7; APLNG, p.2; Energy Australia, p.1.	
Given the previous and current work in this space, further benefits are likely to be marginal. Any further solutions should be voluntary with no increased reporting requirements.	AGL, p.2.	Despite initiatives undertaken by industry to date, and other regulatory changes underway, the Commission considers that further regulatory changes are required to reduce search and transaction costs. See section 4.3.1.
Only industry led options that reduce transaction costs and time should be pursued. Industry has already taken considerable steps to improve capacity trading and can be expected to continue these efforts. Many of these are recent and the benefits not yet realised.	APGA, pp.3, 7; APA, pp.16-17; ESAA, p.3.	
A secondary trading market and central trading platform should be an industry led initiative.	APA, p.13.	

Issue raised	Stakeholder(s)	AEMC response
Capacity trading could be supported through a centralised matching service, or through spread products (eg the gas supply hub spread product).	Energy Australia, p.2.	See section 4.3, which recommends the mandatory creation of capacity trading platforms.
If a pipeline in underutilised, pipeline owners should allow flexible receipt and delivery points.	APLNG, p.1.	The Commission is considering whether additional flexibility in receipt and delivery points is warranted and welcomes feedback in this regard. See section 4.3.4 (Segmentation and flexibility in receipt and delivery points).
Standardisation of capacity rights		
This is a low cost option that could reduce transaction costs and streamline negotiation. Standardisation is vital for liquidity.	Jemena, p.5; MEU, p.16; APGA, p.3; Energy Australia, p.2.	The Commission recommends that standardised primary capacity products be required to be developed by industry, but with regulatory oversight, with the intention of precipitating the standardisation of secondary capacity that is traded. See section 4.3.1.
Standardisation could be achieved through regulation or consultatively through a body such as the Australian Financial Markets Association.	Stanwell, p.3.	
While having a standard contract is beneficial, participants should be able to negotiate alternative terms between themselves.	Origin, p.2.	The intention of standardisation is to reduce search and transaction costs (as shippers would be able to quickly determine the value of a capacity product for sale) and increase liquidity (as a plethora of different products splits the market). On the other hand, customisation of capacity rights provides value to at least one or the other of the shipper or pipeline owner (or else these parties would not agree to them in a GTA) – were standardised products to be made compulsory, this would inevitably reduce the ability of these parties to fine-tune their products. Section 4.3.2 (Standardisation) discusses potentially appropriate approaches in light of this trade-off. The Commission welcomes further feedback in this regard.
The ability to tailor a GTA is beneficial, so complete standardisation should not be pursued. However, this may limit the ability of some shippers to trade capacity with each other.	APGA, p.7; ESAA, p.2.	
Bespoke arrangements under existing GTAs could be maintained to the extent they do not restrict secondary trading.	AEMO, p.1.	
Standardised arrangements should focus on operational aspects of a GTA. Introducing minimum service requirements would also be beneficial.	AEMO, p.1.	

Issue raised	Stakeholder(s)	AEMC response
Many terms are already standardised across shippers, such as credit requirements, nomination timing, responsibilities and obligations.	APGA, p.7.	
Some work has been carried out by individual pipeline operators to standardise GTAs. Standardisation across pipelines is likely to require greater coordination/regulation.	AEMO, p.1.	
The operational capacity transfer service implemented by the gas transmission industry in 2014 is improving consistency of important terms related to capacity trading.	APGA, pp.7-8.	
Standardisation should occur for transactions between pipeline owners and shippers as well as between shippers.	Stanwell, p.3.	The Commission recommends that standardised primary capacity products be required to be developed to the extent necessary to precipitate the standardisation of secondary capacity that is traded. It may also be necessary to standardise some characteristics of secondary capacity. See section 4.3.
Standardisation should occur through the secondary trading market instead of primary contracts. Secondary trading requires a shorter lead time making standardisation very valuable.	APA, pp.18-19.	
Secondary contracts should be standardised. To the extent practicable, primary contracts should also be standardised.	Origin, p.2.	
Short term contracts should be standardised, as these are largely used in secondary trading to reduce transaction costs. They would be used by both shippers and pipelines.	Santos, p.2; GDF SUEZ, p.3.	
Standardisation should apply to new GTAs only.	Stanwell, p.3; Origin, p.2.	Standardisation may have transitional issues as existing GTAs are not currently standardised. Converting existing GTAs to standardised GTAs may impact the value of these GTAs for either the shipper or pipeline owner. It may be appropriate to grandfather these arrangements where counter-parties cannot agree to a contract variation. In this case it would be important that all information relevant to the value of the capacity be published on the capacity trading website. See section 4.3.2 (Standardisation).

Issue raised	Stakeholder(s)	AEMC response
Pipeline owners offering spare firm capacity		
Auctioning spare capacity would ensure the capacity is purchased by the participant who values it most.	Santos, p.2.	See section 4.2 which recommends an auction for contracted but un-nominated capacity.
This would not manage congestion where there is a high level of capacity already contracted. This would need to be combined with options that entice shippers to give up unused capacity.	AEMO, p.2.	See section 4.2, which discusses how an auction for contracted but un-nominated capacity may improve incentives for shippers to trade capacity.
The pool of purchasers is too small to support this option. This option splits the market between pipeline owner capacity and shipper capacity. A single mechanism should be used to maximise liquidity.	Stanwell, p.3.	The Commission is not recommending that the *process* by which spare firm capacity is allocated is regulated (ie, through an auction or open season). As discussed in Chapter 4, the Commission is recommending the standardisation of primary capacity, the auctioning of contracted but un-nominated capacity, and increased information provision requirements on primary capacity sales.
Auctioning spare capacity does not necessarily provide a signal for investment. It might result in capacity being undervalued as shippers are seeking a lower price.	MEU, p.20.	See section 4.2. As noted above, the Commission is not recommending that the *process* by which spare uncontracted firm capacity is allocated is regulated (ie, through an auction or open season). The auction would only apply to contracted but un-nominated capacity.
The AER rejected an APA proposal to introduce an auction mechanism under its queuing mechanism for spare capacity in the 2012 RBP access arrangement. This approach could be revisited.	APGA, p.8; APA, p.28.	
If this option were implemented, it should be a transparent process run by the pipeline owner and not a centralised independent body.	Origin, p.2.	

Issue raised	Stakeholder(s)	AEMC response
Publishing information about spare capacity		
Low cost information measures are already being pursued in the Enhanced Information for gas transmission pipeline capacity trading rule change. These benefits should be given time to take effect.	Jemena, p.5; APGA, p.8; ESAA, p.3.	Despite initiatives undertaken by industry to date, and other regulatory changes underway, the Commission considers that further regulatory changes are required to reduce search and transaction costs. See section 4.3.1.
Industry led capacity listing websites could be further improved, or trading exchanges introduced, without the need for regulation.	APA, p.30.	
Many pipeline owners publish prices and standard GTAs on their website, as well as providing capacity listing platforms that the pipeline owner or shippers can use to advertise spare capacity.	APGA, p.8.	The Commission recommends that the actual (not advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price, be published as it considers that there is an issue regarding actual or perceived non-discriminatory access to primary capacity. See section 4.4.
Information should be published in a central location and in a standardised format.	Origin, p.2; Santos, p.2.	Sections 4.2 and 4.4 discuss information provision requirements for secondary and primary capacity trades, respectively.
Once standard contracts are in place, information about price, duration, location and the parties involved should be published in close to real-time.	Stanwell, p.3.	
The most useful information would be how much capacity each participant has and how much is spare.	Stanwell, p.4.	Through the Enhanced Pipeline Capacity Information draft rule and the draft recommendations in this review regarding information and the Bulletin Board (see Chapter 6), shippers will be able to access information relevant to capacity trading.
Publication of commercially sensitive capacity transactions or volume flows that reveal contractual positions should be carefully considered. For example, long term contracts should not be published.	Esso, p.1; APGA, p.9; Origin, pp.2-3; Santos, p.3.	The Commission is aware that the release of commercially sensitive information on capacity trades may adversely impact the shipper that is selling or purchasing capacity. As a result, capacity trades could be anonymous. Similarly, the Commission recognises that it may be possible to deduce the likely counter-parties of a trade from other information. The Commission will continue to

Issue raised	Stakeholder(s)	AEMC response
Information could be aggregated or delayed to address confidentiality issues.	Esso, p.1; MEU, p.21.	assess the appropriate level of anonymity for capacity trades. See sections 4.3.2 (Anonymity, confidentiality and information provision requirements) and 4.4.2 (Anonymity, confidentiality and information provision requirements) .
Voluntary surrender of capacity		
Participants can already negotiate with a pipeline operator to surrender unused capacity or perform a novation or assignment of contracts with another shipper.	Stanwell, p.4; APGA, p.9; APA, p.30; Santos, p.3.	Noted. The Commission is not recommending a voluntary surrender of capacity mechanism.
This option splits the market between pipeline owner capacity and shipper capacity. A single mechanism should be used to maximise liquidity.	Stanwell, p.4.	
This option is high cost and would outweigh any benefits.	Stanwell, p.4.	
A voluntary surrender mechanism should ensure the pipeline owner does not incur costs or losses as a result of acting as agent - it should not absolve obligations under a take or pay contract.	APGA, p.9; APA, p.31.	
There is little incentive for the pipeline owner to on-sell the capacity. There would need to be clear rules on these requirements, for example whether the pipeline owner must prioritise the shipper's capacity over its own spare capacity.	APA, p.31; Santos, p.3.	
This option could be implemented without regulatory intervention through further development of capacity listing platforms.	APGA, p.9.	

Issue raised	Stakeholder(s)	AEMC response
Approach B - Improve incentives on capacity holders		
Capacity hoarding is not a significant issue as shippers have a commercial interest to trade their available capacity.	AGL, p.3; Origin, p.3.	A shipper with contracted capacity currently has an incentive to sell unwanted capacity prior to the nomination cut-off time. However, the Commission considers that some shippers may have a countervailing incentive not to sell capacity, either because: • it is not core-business ; or • because it may know that the potentially high price of un-nominated capacity sold by pipeline owners may limit entry by shippers that are its competitors in a related market. See section 4.2.1 (Improved incentives for shippers to sell access).
Hoarding may occur where a shipper uses variable capacity or requires an option to expand (risk management). This is not malicious and should not be treated like misuse of market power. This is why mandatory day ahead capacity trading incentives are supported by industry, but not longer term capacity trading.	APGA, pp.10-11; Santos, p.3.	
Capacity hoarding may be benign, or even pro-competitive, as shippers are able to ensure others do not have access to transport capacity at prices below a sustainable level.	APA (Houston Kemp), p.8.	
The AEMC should better explain exactly what it considers to be capacity hoarding (eg, is risk management considered hoarding?), where is it occurring and the issues caused.	APA, p.15.	
Shippers with long term contracts are hoarding capacity to exclude their competitors. This is adding costs to the gas supply chain by preventing new entrants and inhibiting flexibility, short term trading and gas storage.	Encana, p.14.	
This approach addresses some but not all of the issues raised in the discussion paper.	MEU, p.23.	The Commission acknowledges that individual reform options only address specific identified issues.
Pipeline owners should be required to offer interruptible capacity at a lower price than firm capacity. This would make capacity hoarding less attractive to shippers.	MEU, p.22.	See section 4.2, which recommends the introduction of an auction for contracted but un-nominated capacity with a regulated reserve price on all pipelines.
Having both shippers and pipeline operators able to sell spare capacity means no party can profitably withhold capacity when there is demand.	APA (Houston Kemp), p.7.	An incumbent shipper may know that the potentially high price of un-nominated capacity sold by pipeline owners may limit entry by shippers that are its competitors in a related market. An incumbent shipper may therefore decline to sell capacity prior to the

Issue raised	Stakeholder(s)	AEMC response
		nomination cut-off time to gain a competitive advantage. See section 4.2.1 (Improved incentives for shippers to sell access).
Offering spare capacity at the short run marginal cost would undermine the prospect of shippers committing to future take or pay contracts that underwrite investment and affect the competitive position of incumbent shippers in upstream and downstream markets.	APA (Houston Kemp), p.6.	The Commission acknowledges that through the recommended auction, on some occasions, shippers would be able to access very-short term capacity at a potentially low price (ie, at or just above the reserve price) on the occasions that they require it, without the long term commitment of a take-or-pay contract used to underwrite investment. This could, theoretically, create a free-rider effect, whereby shippers do not underwrite capacity because they are able to buy cheaper capacity underwritten by another shipper. However, the Commission does not consider that this is likely to be a material issue in practice for day ahead auctions of contracted but un-nominated capacity. Very few, if any, shippers would be able to rely solely on day-ahead capacity to manage their gas needs, or the gas needs of their customers, over any medium to long term period. The majority of gas users are either relatively inflexible in their usage (for example, residential gas customers) or require a relatively consistent supply of gas to justify sunk investment in immovable assets (for example, a factory). See section 4.2.2 (Investment signals).
A market carriage arrangement should allow for prices to be higher when there are shortages and provide for a regulatory or contractual framework to ensure parties not committing to finance new capacity contribute to the long term cost of making the capacity available.	APA (Houston Kemp), p.7.	
Some of the mechanisms in the discussion paper may stifle pipeline development activity, which are occurring under the current framework.	Stanwell, p.2.	
The main issue is that short term pipeline capacity is being offered at higher prices than the long term contract prices. It should be closer to the marginal cost.	QGC, pp.1-4.	
Selling spare capacity at long term contract prices is not necessarily an exercise of market power, but reduces free rider issues and supports future pipeline investment.	APA (Houston Kemp), p.8.	
Any model should ensure that existing capacity holders are compensated and that there are no financial imbalances.	GDF SUEZ, p.4.	An important advantage of the auction mechanism proposed is that it would not substantially impact existing capacity rights held by shippers – shippers typically already lose their firm capacity rights at the nomination cut-off time. See section 4.2.2 (Existing nomination and re-nomination rights).

Issue raised	Stakeholder(s)	AEMC response
	Compulsory capacity reallocation	
Interruptible pipeline capacity should be sold at a discount price to improve utilisation. Most parties would prefer firm capacity, but it's unavailable. They are penalised with higher prices.	Esso, p.1; MEU, p.12.	See section 4.2, which recommends the introduction of an auction for contracted but un-nominated capacity with a regulated reserve price on all pipelines.
If designed well (drawing from international experience) the complexity, cost and impact on contract holders could be minimised.	AEMO, p.2.	See section 4.2.2 and 4.2.4 which discuss trade-offs and design considerations for the recommended auction.
Capacity should be allocated to the parties that value it most, compared to a queuing methodology. This is the most efficient method for capacity allocation and provides a clear signal for augmentation.	MEU, p.10.	The recommended auction provides a market based mechanism to price and allocate potentially scarce capacity. Through their bids, shippers indicate the value they place on the un-nominated capacity. The auction would result in the un-nominated capacity being made available to any shipper that values it greater than the cost of its provision, and, in the case that there is more demand for un-nominated capacity than that available, to the shippers that value it the highest. See section 4.2.1 (Efficient capacity allocation).
Overseas markets that use this mechanism are attempting to solve issues that are not applicable to the east coast.	Stanwell, p.4.	The recommended auction is intended to: improve incentives for shippers to trade capacity; provide non-discriminatory access to contracted but un-nominated capacity at a price consistent with that expected in a workably competitive market; allocate capacity to the shippers that values it the highest as indicated in their bids; and allow for better informed decision making by shippers and other parties, who have full transparency of the outcomes of the auction. The Commission considers these benefits warrant the auction's introduction. See section 4.2.1 (Improved incentives for shippers to sell access).
There would be little incentive for shippers to enter into long term contracts given the free-rider issue.	Stanwell, p.4.	As noted above, the Commission acknowledges that through the recommended auction, on some occasions, shippers would be

Issue raised	Stakeholder(s)	AEMC response
Free rider issues can be minimised by designing the mechanism to maintain long term incentives.	AEMO, p.2.	able to access very-short term capacity at a potentially low price (ie, at or just above the reserve price) on the occasions that they require it, without the long term commitment of a take-or-pay contract used to underwrite investment. This could, theoretically, create a free-rider effect, whereby shippers do not underwrite capacity because they are able to buy cheaper capacity underwritten by another shipper. However, the Commission does not consider that this is likely to be a material issue in practice for day ahead auctions of contracted but un-nominated capacity. See section 4.2.2 (Investment signals).
Forcing a pipeline owner to sell short term capacity at a low or clearance price reduces the incentive on shippers to hold long term capacity. Also, long term contracts are not necessarily in place for the life of the contract and the pipeline owner does not recoup all its costs from firm long term services.	APA, pp.13, 33.	
The over-sell and buy-back mechanism facilitates free riding by providing access to capacity that has been funded by another party.	APGA, p.11.	See section 4.2.2 (Investment signals). Note that the Commission is not recommending the over-sell and buy-back mechanism.
Some shippers require the flexibility to use their reserve capacity within the gas day in response to changing conditions.	Stanwell, p.4; Santos, p.4.	Notwithstanding concerns raised in section 4.2.2 (Existing nomination and re-nomination rights), an important advantage of the auction mechanism proposed is that it would not substantially impact existing capacity rights held by shippers – shippers typically already lose their firm capacity rights at the nomination cut-off time. It might, however, result in a higher utilisation of the pipeline and so an implicit reduction in the firmness of capacity re-nominations that some shippers may rely on during the gas day.
The over-sell and buy-back mechanism is the most market-based option of the capacity reallocation options put forward. It would seem to have the least impact on existing property rights.	APLNG, p.2.	
Existing property rights should not be impacted without compensation. GTAs are long term investments that underwrite the pipeline.	Stanwell, p.2; Esso, p.1; ESAA, p.3; Origin, p.1.	
UIOLI provisions may impact a shipper's ability to utilise the linepack park and loan tolerance associated with its capacity. This may not be evident from the actual capacity being used each day.	AGL, p.2.	
A modified over-sell and buy-back mechanism should be introduced.	QGC, p.9.	See section 4.2 which explains the Commission's recommendation to introduce an auction for contracted but un-nominated capacity with a regulated reserve price on all pipelines.

Issue raised	Stakeholder(s)	AEMC response
Firm day ahead UIOLI does not need to be regulated as the market is already able to offer this on a voluntary basis. Regulation would infringe on existing capacity rights to re-nominate and would reduce flexibility.	APGA, p.12; Origin, p.4.	The Commission recognises that the recommended auction is in effect a form of the day-ahead UIOLI mechanism described in the AEMC's discussion paper on pipeline regulation and capacity trading. However, the Commission considers that the recommended auction, with a regulated reserve price, has the advantage of providing non-discriminatory access to competitively priced capacity. See section 4.2.1. As noted above, an important advantage of the auction mechanism proposed is that it would not substantially impact existing capacity rights held by shippers.
Short term capacity trading products should be aligned with short term gas products.	Esso, p.1.	It may be appropriate to consider harmonisation of nomination cut-off times as part of the harmonisation of the gas day start time, as recommended in stage 1 of this review, or through a standard developed by industry. It may also be appropriate that the capacity nomination cut-off is set with regard to any timing requirements relating to nominations for the gas commodity. See section 4.2.2 (Existing nomination and re-nomination rights).
Compulsory long term UIOLI is likely to have very poor consequences for investment and could impact liquidity.	APGA, p.12; APA, p.33.	While a longer-term UIOLI mechanism might result in more (and more valuable) capacity being released to other shippers, it has two clear drawbacks compared to the recommended day-ahead UIOLI mechanism. See section 4.3.5.
Shippers secure firm contracts at a level to manage their risks, including seasonal fluctuations. If a regulator imposes UIOLI, the regulator should also be responsible for security of supply, including compensation to a shipper if they result in financial loss.	AGL, p.2; Origin, p.4; Energy Australia, p.2; Santos, p.4.	Notwithstanding concerns raised in section 4.2.2 (Existing nomination and re-nomination rights), an important advantage of the auction mechanism proposed is that it would not substantially impact existing capacity rights held by shippers – shippers typically already lose their firm capacity rights at the nomination cut-off time. It might, however, result in a higher utilisation of the pipeline and so an implicit reduction in the firmness of capacity re-nominations that some shippers may rely on during the gas day. The Commission is not recommending a long term UIOLI auction, which would impinge on the existing property rights of shippers and therefore may impact on shippers' security of supply.

Issue raised	Stakeholder(s)	AEMC response
An alternative would be to introduce a use-it-or-auction-it mechanism. Shippers would be required to offer unutilised capacity on a trading platform, but would retain control of the sale and trading process.	QGC, p.9.	By allocating auction revenue to pipeline owners, shippers that hold capacity might then have a stronger incentive to sell capacity prior to the nomination cut-off time (even if it is selling to a competitor), rather than the pipeline owner recouping the revenue for that sale, stimulating the secondary capacity market. See section 4.2.1 (Improved incentives for shippers to sell access).
Limitations in GTA provisions for trading by pipeline owners		
This mechanism would reduce barriers to capacity trading. These provisions should be phased out and apply to all new GTAs.	Stanwell, p.4; APLNG, p.2; GDF SUEZ, pp.3-4.	The Commission is working with the ACCC to understand the prevalence of these limitations, and has not specifically recommended that any such limitations be prohibited at this stage. We will continue to work with the ACCC in this regard. Standardisation of GTAs may also address any limitations in GTA provisions for trading by pipeline owners. See section 4.2.
Shippers with firm services should have no influence over the availability or price of interruptible services for that capacity.	Encana, p.5.	
Any contractual provisions that limit capacity trading should be removed before considering arrangements to manage congestion.	AEMO, p.2.	
These can be benign or even pro-competitive. Specifying receipt and delivery points is normal and changing these can affect the capacity available to other shippers. Favoured nation clauses can protect a foundation shipper from some risks and can support investment in the pipeline infrastructure.	APGA, p.13; Origin, p.4; APA (Houston Kemp), p.8.	
The prevalence and issues caused by these GTA provisions that limit capacity trading should be investigated before proposing regulation.	APA, p.33; Origin, p.4.	

Issue raised	Stakeholder(s)	AEMC response
Reserve capacity for short term trading		
This is not compatible with contract carriage arrangements as long term contracts underwrite the development and expansion of pipeline assets. It penalises foundation shippers.	AEMO, p.2; APGA, p.13; APA, p.34.	Noted. The Commission is not recommending this approach in light of these concerns.
Foundation shippers would likely be overcharged for transport in order to subsidise the pipeline's reserve capacity.	Stanwell, p.5; APA, p.34; Santos, pp.3-4.	
The pipeline owner is already able to build a pipeline with a larger capacity than required.	Stanwell, p.5.	
Reserving capacity is not consistent with the objective of delivering a market based solution.	QGC, p.8.	
This could result in inefficient operation of the pipeline, if it is oversized. Who would bear the cost of the pipeline capacity available for short term sales?	Origin, p.5.	
Approach C - Improve incentives on pipeline owners		
Pipelines should be regulated to address the natural monopoly issues associated with pipeline ownership.	AGL, p.3; MEU, p.24; Encana, pp.9, 15.	Over the course of the review, the Commission has identified concerns with outcomes in the market arising from a lack of incentives on pipeline owners to offer primary capacity at a price expected in a workably competitive market, or to provide a level of service in the secondary market commensurate with what would be expected in such a market. However, feedback received from stakeholders has tended to suggest that there are more pressing areas of focus for this review regarding the reallocation of capacity between shippers. The Commission has consequently developed the package of measures described in Chapter 4 which are targeted specifically at
Pipelines that have no competitor should be subject to cost of service regulation or at least a rate cap based on a reasonable return.	Encana, p.15.	
If this Approach is pursued, Approaches A and B may not be necessary.	AGL, p.3.	

Issue raised	Stakeholder(s)	AEMC response
		addressing these issues. While it is not recommending broader changes to the current regime for the economic regulation of pipelines at this stage, the Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In its work, the ACCC will be able to draw upon information gathering powers that are not available to the AEMC. In the event that the ACCC was to find that there are issues to be addressed in relation to the incentives acting on pipeline owners – or in relation to the ability of the current regulatory regime to act as an effective constraint on these – the Commission may look to supplement its draft recommendations in this regard.
Changes to economic regulation of pipelines		
The coverage provisions are currently inadequate at preventing monopoly rent seeking behaviour. It is very difficult to secure coverage, even where the asset provides a monopoly service and it would be uneconomical to duplicate the pipeline to break the monopoly. It should be expanded beyond downstream competition to cover those with market power on pipelines.	MEU, p.11; Energy Australia, p.3.	As noted above, the Commission is not at this stage recommending changes to the economic regulation of pipelines. The Commission intends to continue to work with the ACCC as its inquiry focuses on transportation arrangements following its recent hearings. In light of the ACCC's findings, the Commission may supplement its draft recommendations with those concerning the economic regulation of pipelines.
The coverage provisions are not fit for purpose as they do not relate to whether the pipeline operator can exercise market power.	GDF SUEZ, p.4.	
Pipeline owners actively seek revocation of coverage because it allows them to gain a better return on their assets through higher prices.	MEU, p.23.	
Any consideration of regulatory arrangements should include pipeline services and other gas facilities (such as storage) - not just reference services.	AEMO, p.3; Santos, p.5.	

Issue raised	Stakeholder(s)	AEMC response
This option should not be pursued unless other intermediary steps are unsuccessful.	Origin, p.5; APLNG, p.2.	
A problem has not been identified in the discussion paper.	Jemena, p.5; APA, p.34.	
Interfering with the gas access regime would impact on private investment decisions and existing property rights at a very high cost. It could create sovereign risk issues that could affect the ability to attract capital for future investment.	Jemena, pp.1, 7.	
The gas access regime was designed to target vertically separated gas infrastructure. Consistency of coverage criteria was a deliberate decision and provides an appropriate constraint on the monopoly gas transmission pipeline owners.	APGA, pp.3, 13-14.	
Changing the coverage criteria would not provide further incentives for the secondary trade of contracted but unutilised capacity.	APA, pp.20-21.	
The Productivity Commission has stated that the purpose of the access regime is to improve allocative efficiency and not productive efficiency.	APGA, pp.18-19.	
Comments about the access regime should not be applied to the coverage criteria, as the NGL imposes a very different framework once a pipeline meets the coverage criteria. The NGL imposes price regulation and addresses practices that involve excessive, monopolistic or gouging pricing.	APA (Houston Kemp), p.9.	
The discussion paper appears to suggest that criterion (a) is too high a hurdle for determining price regulation. However, changing (a) may result in regulation that does not deliver net economic benefits. The NGO is focussed on economic efficiency.	APA (Houston Kemp), p.10.	

Issue raised	Stakeholder(s)	AEMC response
This option may not be necessary as shippers will be in competition with the pipeline owner for the sale of secondary pipeline capacity.	Stanwell, p.5.	
This option may not be necessary as the current framework has been effective in facilitating investment. It would involve a very high degree of cost and change.	QGC, p.14.	
Any further regulation should be on an 'incremental pricing' basis - to separate new investment from existing investment for the purpose of calculating prices.	Stanwell, p.5.	
Changing the gas access regime would have significant flow on effects for competition policy.	APGA, pp.4, 13-14.	
Limitations in GTA provisions for trading by shippers		
Mechanism would reduce barriers to capacity trading. These provisions should be phased out and apply to all new GTAs.	Stanwell, p.5; APLNG, p.2; GDF SUEZ, p.4.	The Commission is working with the ACCC to understand the prevalence of these limitations, and has not specifically recommended that any such limitations be prohibited at this stage. We will continue to work with the ACCC in this regard. Standardisation of GTAs may also address any limitations in GTA provisions for trading by shippers. See section 4.2.
This option is necessary as a precursor before the introduction of a new capacity trading mechanism.	QGC, p.14.	
Contracts could be submitted to the AER for review.	AEMO, p.3.	
Pipeline operators could be required to provide minimum pipeline services, such as re-nominations, delivery point flexibility, allocations and title transfer.	AEMO, p.3.	
This option should include and investigation of any practical limitations. For example, GTA provisions might be included due to the technical requirements of the pipeline.	Origin, p.6.	
There is no evidence that standard GTA provisions limit capacity trading.	APA, p.35	

Table C.2 Summary of submissions to Wholesale Gas Markets Discussion Paper

Issue raised	Stakeholder	AEMC response
Ability of the status quo to promote the COAG Energy Council Vision		
AEMO believes the Energy Council Vision can be delivered through developments to the existing wholesale gas market if there are effective capacity trading arrangements, enhanced information and commitment from industry. More fundamental change to gas market design may be required in the future if the markets do not evolve to meet the vision.	AEMO, p. 1.	As set out in Chapters 4 and 6, development of the Commission's recommended Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access and information provision. In this respect, the package developed by the Commission is a congruent set of inter-related recommendations that mutually reinforce the objectives of each another. In addition, Chapter 7 outlines the sequencing of the Commission's recommendations.
APA considers that the current market is still evolving – it is too early to implement a particular market design based on assumptions about uncertain future market development. APA advocates an incremental, market-led development approach which retains the flexibility to modify the market framework as the market's needs develop over time.	APA, pp. 2-3.	The Commission considers that an incremental, market-led development will not promote the Vision or NGO going forward. See Chapters 2 and 3.
The ESAA maintains an incremental approach to reform that has appropriate regard for existing contracts is the best approach to facilitating trading, but notes that the outcomes of the AEMC's assessment of current arrangements are highly relevant to the development of a long term market reform strategy.	ESAA, p. 3.	
ERM has concerns that the three high level market design concepts put forward by discussion by the AEMC all involve a significant overhaul of the existing trading arrangements on the east coast and that such changes would significantly reduce competition within Australia's east coast gas market.	ERM, p. 1.	

Issue raised	Stakeholder	AEMC response
ERM believes that a fourth option should also be investigated that builds upon the current arrangements and investigates areas for enhancement.		
Hydro Tasmania welcomes this review as an opportunity to remove existing inconsistencies within the east coast market (including the different facilitated markets as well as market carriage and contract carriage transportation arrangements) and create a uniform east coast gas market. Hydro Tasmania believes that fundamental change is required to achieve a transparent and efficient market. Significant changes to the structure of the market should not be ignored on the sole basis that it may be cumbersome to implement such changes and should be decided on a carefully completed long term cost-benefit analysis. Given that this would be a significant change, a staged approach may be an appropriate option to transition to such a design.	Hydro Tasmania, p. 1.	
Domestic gas users have become price takers in an international market. The price volatility introduced by the scale and international price linkage of the LNG export industry requires improved markets and risk management. The current East Coast markets are not designed to cope with large and temporary swings in supply/demand conditions.	EnergyAustralia, p. 1.	Chapter 2 outlines how achieving a liquid wholesale gas market on the east coast will ensure the industry is robust to these changes. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends the STTM design then be simplified to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times. The Commission is aware that many participants in the STTM hubs, particularly large users, highly value the certainty of supply provided. While such a mechanism would be provided in the Southern Hub, the Commission notes that there may also be a need to implement a mandatory balancing mechanism at the Northern Hub, if the liquidity of trading is insufficient to give participants certainty of delivery. This would be an important prerequisite to the simplification of the STTM design.

Issue raised	Stakeholder	AEMC response
The ESAA is supportive of the AEMC examining the appropriateness of the facilitated market designs and developing a long term strategy for the location of facilitated markets on the east coast. However, the ESAA considers it prudent for the AEMC to first consolidate its position on the current state of the east coast market and to understand whether the NGO and COAG Vision are achievable under the current gas market framework.	ESAA, p. 2.	The achievability of the Vision is discussed in section 2.2.
GDFSAE states that with the dramatic growth now underway in the gas industry it is unlikely that the incremental development process will be sufficient to meet future needs for liquidity, transparency, trading options, etc.	GDFSAE, p. 5.	The Commission agrees with this view.
The MEU restate their position on the Stage 1 findings and recommendations, indicating that, on balance, there is no need for wholesale redesign of the STTM or the DWGM. The MEU comment that, by any measure, the DWGM had proved to be a resilient and reliable market. The MEU does agree that there are aspects of both the STTM and DWGM where improvements could be made but this did not require redesign. The MEU is concerned that, despite these observations, the AEMC did not listen to the views of end users active in the STTMs and the DWGM and persisted in recommending redesign.	MEU, p. 7.	See sections 5.3 and 5.4. The Commission considers that the changes to the DWGM represent a refinement of the existing virtual hub.
Origin considers there are a number of improvements that could be made to the DWGM, STTM and gas supply hub that could enhance market efficiency. Origin considers that the main issue in the DWGM and STTM is the complexity and cost to operate in these markets. The presence of a number of ancillary prices other than the traded commodity price makes these markets	Origin Energy, pp. 2-3.	The Commission considers that an incremental, market-led development will not promote the Vision or NGO going forward. See Chapters 2 and 3.

Issue raised	Stakeholder	AEMC response
complex to trade in as the costs and risks are uncertain and difficult to hedge. This creates a barrier to participation. If these unnecessarily complex elements of the markets were simplified, specifically by linking the ancillary prices back to the commodity price, this would improve participants' ability to manage risk, enhancing price discovery and potentially fostering greater participation and liquidity.		
Qenos favours maintaining or enhancing existing markets operating via the DWGM and STTM. Qenos does not support a move to change the STTM to a voluntary market that is solely focussed on providing gas balancing arrangement without an alternative that enables supply at major demand hubs.	Qenos, p. 2.	The Commission considers that an incremental, market-led development will not promote the Vision or NGO going forward. See Chapters 2 and 3. As noted above, once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends the STTM design then be simplified to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times. The Commission is aware that many participants in the STTM hubs, particularly large users, highly value the certainty of supply provided. While such a mechanism would be provided in the Southern Hub, the Commission notes that there may also be a need to implement a mandatory balancing mechanism at the Northern Hub, if the liquidity of trading is insufficient to give participants certainty of delivery. This would be an important prerequisite to the simplification of the STTM design. See section 5.4.
Visy consider that the STTMs have opened up genuine supply alternatives to users that did not exist before the advent of these markets. Visy also state that the STTMs have allowed users to procure some or all of their gas without the need to contract for transmission pipeline capacity. Visy state that there have been a large number of large users enlisting in STTMs within just the last year as end users start to recognise the benefits and consider that the view that wholesale users just trade their own gas no longer applies as end-users begin to expand their direct wholesale participation via STTMs.	Visy, pp. 4-5.	
Stanwell state that, given the success of the east coast gas market in facilitating LNG development, and the fact that the LNG projects can internally manage their gas operations, the case for fundamental change to the design of the east coast gas market is not compelling.	Stanwell, p. 6.	Chapter 2 outlines the Commission's view on the case for change.

Issue raised	Stakeholder	AEMC response
Ability of Concept 1 to promote the COAG Energy Council Vision		
There are potential consequences for balancing outcomes associated with this concept – in particular if applied to Victoria. A Melbourne demand hub with the pipelines connected to it working on a contract carriage basis implies a loss of coordination. The core issue in managing the Victorian network is to manage within-day constraints. Under a contract carriage model there is no price basis for managing the trade-off between supply and demand across the day. The Melbourne demand hub would then be the only market for resolving differences between supply and demand, and could mean that demand or LNG at Melbourne could be left to resolve all issues. Further consideration should be given to the coordination of pipeline and network operation under Concept 1.	AEMO, p. 7.	The Commission is concerned that demand variability on the spokes would result in Dandenong LNG being scheduled more frequently than currently to balance the DTS.
AGL does not support further consideration of concept 1, as introducing additional hubs (i.e. Gladstone, Iona and Longford – in addition to Wallumbilla and Moomba) is likely to increase market complexity and participants transaction costs. AGL can only assume that these costs and complexities will also create barriers to entry. AGL considers that it is also unclear what benefits a 5 hub model would produce when the east coast gas market is still underscored by relatively few market participants – buyers and sellers. Without a sufficient level of participation trade at each new hub is likely to be too low for substantial liquidity and transparency to eventuate.	AGL, p. 1.	The Commission considers that developing numerous physical hubs on the east coast splits trading liquidity and is unlikely to result in the emergence of a meaningful reference price that is reflective of underlying supply and demand conditions. This lack of liquidity undermines any locational signals provided under Concept 1. The Commission also considers that this concept increases market complexity and participants transaction costs. The Commission considers that the technical characteristics of the DTS mean that effective capacity trading and hub services arrangements are unlikely to be practically achieved and so a system of physical hubs and contract carriage is not appropriate in Victoria. In particular, the multitude of entry and exit points and need to flow gas across the entire DTS, mean that it is likely to be efficient for a hub operator to manage flows via a virtual hub and balance the system on behalf of participants.
APA does not believe there is a case for the multiple market hubs suggested in Concept 1. The ideal number of trading locations is ultimately a question for the market to answer.	APA, p. 4.	

Issue raised	Stakeholder	AEMC response
APA believes that an efficient market structure in line with option 1 (a physical market) might feature: (1) a northern voluntary supply hub at Wallumbilla, with a single trading point supported by hub services; (2) a southern voluntary supply hub in Victoria (appropriate location to be determined); (3) market-based balancing markets at major demand centres; (4) contract carriage pipelines linking supply hubs; (5) a well-developed and fully functioning secondary pipeline capacity market with appropriate incentives; and (6) effective, transparent information provision through the Bulletin Board that shows forecast daily gas flows into and out of zones, line pack status, and scope for real time reporting during incidents.		In addition, the Commission's view is that implementing contract carriage as a package with physical trading hubs is not suited for the DTS due to the following practical challenges: • Defining firm point-to-point rights on the DTS is likely to be practically difficult given the available capacity between any two points is significantly influenced by the expected pattern of injections, withdraws and flows across the entire network. • Likely narrow imbalance tolerances and penalties would present a barrier to entry and involve large monitoring costs for shippers (metering and information systems). • Variability of flows on the contract carriage 'spokes' is likely to result in the high cost Dandenong LNG facility being scheduled more frequently than currently to balance the inner ring. In addition, the success of contract carriage more broadly in promoting the Vision depends crucially on the fluidity and effectiveness of secondary trading of capacity measures, which, while this is being promoted as part of the east coast review, will be unproven initially. Uniquely, in Victoria the introduction of an entry-exit model would represent an evolutionary step and therefore the benefits of such a virtual hub could be realised with much lower (although still material) implementation costs.
APGA considers that a series of physical, voluntary hubs could be developed to enhance liquidity in the existing market without significant changes to the current regulatory settings. APGA state that a version of Concept 1, with supply hubs at Wallumbilla, Moomba and in Victoria and supported by voluntary balancing markets in Victoria, Sydney, Adelaide and Brisbane, could support increased liquidity of marginal gas at these central locations which, with increased supply, could develop into a meaningful secondary market.	APGA, p. 18.	
EnergyAustralia support the introduction of more trading locations which provides flexibility and localised pricing. However, new entrants and major users would find it more difficult to participate directly in this model. This model is an efficient way to facilitate the optimisation of existing portfolios and will enable more dynamic market responses to price shocks and supply/demand condition changes. However it may cement the role of long term supply and transport contracts and current market structure.	EnergyAustralia, p. 2.	

Issue raised	Stakeholder	AEMC response
The replacement of the DWGM with physical trading hubs at Iona and Longford and a balancing hub at Melbourne could facilitate more efficient pipeline investment arrangements by allowing direct customer involvement and investment in pipelines. It is difficult to make a definitive judgment on this though, without full consideration of the available options for managing investment under a virtual hub model. The likely adequacy of market liquidity will also be an important consideration, as well as potential barriers to new market entry.	ESAA, p. 4.	
GDFSAE is inclined to be more supportive of this model compared to the other two, as it represents a reasonable evolution of the existing arrangements and has the potential to provide a good balance of liquidity and locational signals.	GDFSAE, p. 3.	
GDFSAE suggests that under Concept 1, consideration should also be given to including a hub at Culcairn, which is becoming increasingly important to gas flows between Victoria and NSW.	GDFSAE, p. 3.	
GDFSAE considers that splitting the existing DWGM into three new hubs – two trading hubs at Longford and Iona, along with a balancing hub at Melbourne – provides a more effective locational signal for new investment, and should be more able to deal with pipeline congestion than the current DWGM.	GDFSAE, p. 3.	
Hydro Tasmania supports further analysis of Concept 1 and requests the AEMC to continue the investigation by completing a comprehensive and competitive cost-benefit analysis to better understand the optimal structure. Hydro Tasmania believes such an analysis would include the potential limitations that may arise with Concept 1 by setting fixed physical hubs. The design of such a market	Hydro Tasmania, pp. 1-2.	

Issue raised	Stakeholder	AEMC response
should take into account the potential long term changes to supply and what impact that may have on the supply proximity to the defined physical hubs. Another potential challenge may be the relatively small market with few participants which could lead to some of the physical trading hubs being illiquid.		
QGC consider that this could represent an overall improvement on the current structure as there are harmonised trading arrangements across the east-coast. Multiple market designs make trading complex, inefficient and costly for participants. However, QGC also see the following issues with Concept 1: • The underlying market is too small to support this market design. • It would need to be underpinned by a well-functioning secondary capacity trading scheme. • Arguments that sharper locational prices, generated under this model, could assist in identifying contractual congestion on pipelines is not an adequate basis to implement changes.	QGC, pp. 3-4.	
Stanwell's long term vision for the gas market is for one modelled on the US market with logical commodity pricing points representing physical locations on the gas network, such as Wallumbilla, Moomba, Iona etc. Stanwell note that not all of the hubs and demand centres would need to be implemented at once. The markets could be developed in a staged manner in consideration of the priority and need. In addition, Stanwell state that the design of the hubs and demand centres could be easily and	Stanwell, p. 8.	

Issue raised	Stakeholder	AEMC response
cheaply replicated if future need for new locations arose, and, conversely, this relatively cheap market set up could also lend itself to removing markets in the future if they prove to be unutilised due to participant or market changes.		
The MEU state that Concept 1 proposes trades occur at supply points rather than demand points yet provides no indication why this change will provide a different outcome to that currently seen. The MEU consider that unless a gross pool approach is implemented thereby preventing the trading hubs from bilateral trading, then it is not clear how the change will deliver the outcome sought.	MEU, p. 7.	The Commission considers that developing numerous physical hubs on the east coast splits trading liquidity and is unlikely to result in the emergence of a meaningful reference price that is reflective of underlying supply and demand conditions. See sections 5.2 and 5.3.
The MEU's overall assessment of option 1 is that unless bilateral trades are included into the trading hub operation, the revealed prices will be much the same as at the current STTM and will only assess the value of gas at the margin. The balancing hubs will be less transparent than the STTM hubs in identifying the costs of balancing and allocating equitably the costs of balancing to the causers. Issues with pipeline capacity trading, augmentation, hoarding, are not addressed, even implicitly. Based on the limited information provided, the MEU considers that the changes proposed would not deliver a benefit to overcome the detriments consumers would face when assessed against the status quo. In particular, the end users currently gaining a benefit from being within the DWGM and STTM would lose the flexibilities they currently have for limited (if any) benefit.	MEU, pp. 14-15.	The Commission considers that , over time, various price reporting agencies may enter and successfully report reference price as they do in other gas markets (typically based off an amalgam of both exchange trades and bilateral trades). However, these bodies provide a service in the commercial interests of gas market participants and their role in the Southern Hub will emerge over time if demanded by the market. As set out in Chapters 4 and 6, development of the Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times.
Origin cautions against any rush to establish hubs in multiple locations without addressing the underlying concern as to whether there would be sufficient volumes to support liquidity and any meaningful trading activity.	Origin Energy, p. 2.	The Commission considers that developing numerous physical hubs on the east coast splits trading liquidity and is unlikely to result in the emergence of a meaningful reference price that is reflective of underlying supply and demand conditions.

Issue raised	Stakeholder	AEMC response
Qenos considers that Concept 1 is unlikely to result in the desired liquidity due to there not being enough participants across the entire market to create a meaningful reference price at each hub. Qenos also consider that firm transportation rights would need to be introduced to improve the ability for end users to trade gas and that multiple transportation agreements would need to be in place for end users to source gas from more than one hub.	Qenos, p. 3.	In addition, the success of contract carriage more broadly in promoting the Vision depends crucially on the fluidity and effectiveness of secondary trading of capacity measures, which, while this is being promoted as part of the east coast review, will be unproven initially. The Commission considers that, even if secondary trading of pipeline capacity were to develop sufficiently in Victoria, participants would be faced with significant associated transaction costs, eg, where traders need to move gas across the DTS and so require capacity to do so.
Santos consider that too many physical hubs will split the buyers and will result in very thin trading on some hubs. Eastern Australia does not have the demand or trading counter-parties to warrant this.	Santos, p. 4.	
The replacement of STTMs and DWGM with mere balancing platforms is not supported by Visy.	Visy, p. 3.	
Supports the development of gas supply hubs at Wallumbilla, Moomba and Victoria, where the same products are traded.	Esso, p. 2.	Price discovery at both hubs included in the Commission's draft recommendations would be via exchange based continuous trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. The Commission considers that exchange based trading provides participants with greater flexibility in how they buy and sell gas than the current reverse auction mechanism. Day-ahead and balance-of-day spot products, and longer forward products, can also be traded on the exchange, creating transparency around future price expectations.

Issue raised	Stakeholder	AEMC response
Ability of Concept 2 to promote the COAG Energy Council Vision		
Virtual hub development would be a significant undertaking in the context of the east coast gas market. However, the implementation of virtual hubs could be considered further if there is a failure to achieve both competitive hub service provision and pipeline capacity trading arrangements.	AEMO, p. 4.	Virtual hubs facilitate trading by allowing market participants to trade anywhere within the hub without having to book pipeline capacity to transport the gas between particular points. This reduces transaction costs and is a particular advantage on networks where there may be several nodes at which capacity bookings may otherwise be required. However, the need to manage flows within the hub and less precise investment signals can be considered disadvantages with the virtual hub model. Consequently, the Commission's preferred model does not feature virtual hubs over the majority of the pipeline network. As set out in Chapters 4 and 6, development of the Commission's recommended Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access and information provision. In this respect, the package developed by the Commission is a congruent set of inter-related recommendations that mutually reinforce the objectives of each another. This is also discussed in sections 5.2 and 5.3.
A key selling point of virtual hubs is that they internalise the complexities, and hence hurdles to efficient trading, associated with the need to pair commodity and capacity transactions in order to pool participants into a single market. However, the virtual hubs proposed in Concept 2 would solve only a relatively small component of the capacity trading issue. Further, the relatively small coverage of the virtual hubs means that, depending of participation costs, participants may by-pass the hubs and carry-out wholesale transactions at alternative locations.	AEMO, p. 8.	
AGL supports further consideration of concepts 2 and 3 – the virtual trading hub models, noting that further analysis, including cost/benefit assessments, will provide further clarity on their merit. AGL notes that consideration of the virtual hub models must take place concurrently, and with regards to, the AEMC’s work on pipeline capacity trading.	AGL, Attachment 1, p. 2.	
This proposal is more consistent with an incremental approach to gas market reform in the Victorian market to the extent it retains a virtual hub that covers the Victorian DTS. But the implementation of a virtual hub at Wallumbilla is a significant change that would require economic regulation of pipeline arrangements in that region, the merits of which require further consideration. The rationale for, and implications of including the Brisbane demand hub in the northern virtual hub must also be examined.	ESAA, p. 4.	

Issue raised	Stakeholder	AEMC response
The inclusion of the Wallumbilla hub in this model is likely to be a challenge as a relatively large portion of gas transits the APA Wallumbilla compound on the SWQP rather than entering the RBP. However, the exclusion of the Wallumbilla hub would greatly reduce the reach of the hub and its ability to pool together potential buyers and sellers. SWQP may be a better location as it has the potential to pool together participants trading in the northern and southern markets. The SWQP is one of the key capacity trading links on the east coast. Linepack on the SWQP may also aid the management of constraints within the hub.	AEMO, p. 8.	The Commission's consideration of the Northern Hub is outlined in section 5.3. Over the majority of the east coast of Australia, the geographically distant nature of production and demand centres, with long, point-to-point pipelines, means that there would be significant costs associated with virtual hubs in terms of less precise investment signals and reduced competition to provide additional pipeline capacity. Efficient investment outcomes form a very important part of the NGO, when assessing long term benefits to consumers. Consequently, under the Commission's recommended roadmap, the majority of pipelines would continue to operate a contract carriage regime, similar to that which currently exists. The Commission therefore does not consider that including the SWQP is likely to meet the criteria that should be considered in determining whether and where a virtual hub is appropriate, as outlined in section 3.3. In addition, the rationale for including the RBP in this concept was that a broader range of diverse users could be captured as compared to the SWQP. The Commission does, however, recognise the importance of access to pipeline capacity, and so recommends a suite of reforms to improve the contract carriage model. This is outlined in Chapter 4.
APA considers that the virtual market concepts (Concepts 2 and 3) do not address, and may even exacerbate, the failures identified in a number of reviews in relation to market carriage, where investment is delayed or stopped due to free rider issues, inefficient regulatory processes and the lack of firm transmission rights.	APA, p. 4.	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3. The eventual size of the Northern Hub is discussed in section 5.3. Investment impacts can be partially mitigated in virtual hubs

Issue raised	Stakeholder	AEMC response
APLNG supports Concept 2 and considers it the best balance between establishing the COAG Vision and ease of implementation. APLNG further hope that this northern hub could include Moomba over time. As the market matures, APLNG consider that the goal could be to implement Concept 3.	APLNG, p. 2.	through the implementation of an entry-exit regime. Under entry-exit, auctions are held for entry capacity and can be held for exit capacity, depending on the characteristics of the network. These auctions reveal prices that signal the need for investment. This is a key difference compared to the market carriage arrangements in Victoria. Due to the characteristics of the pipeline system, a contract carriage framework with physical hubs may be more suitable than a virtual hub with market carriage or entry-exit. Outside of Victoria, the capital intensive nature of the long point-to-point pipelines means that the weakening of investment signals from implementing a virtual hub may outweigh the benefits. Similarly, due to the Victorian transmission network be a meshed system, the efficiency benefits of a hub operator coordinating flows within a virtual hub may outweigh the benefits of price signals provide under contract carriage. It is important for gas market design to take account of the physical nature of the pipeline system in order to explicitly acknowledge these trade-offs.
Hydro Tasmania considers that Concept 2 does not address existing market inconsistences; the mix of virtual hubs connected by contract carriage transmission pipelines does not significantly change the current inconsistencies in the market. Hydro Tasmania therefore believes that Concept 2 is not an optimal solution.	Hydro Tasmania, p. 1.	
The MEU state that Concept 2 proposes that the DWGM effectively operates as now and there is a northern hub developed similar to the DWGM. The MEU consider that, although the bidding structure of the DWGM does provide a basis for delivering a market price that reflects the price for gas across the DWGM, there are concerns that the price does not fully reflect the bilateral gas trades as it also includes the cost of balancing.	MEU, p. 7.	Section 5.2 outlines the benefits of transitioning the existing arrangements in Victoria to the Southern Hub model.
The MEU states that, based on the limited detail provided, this concept is better than Concept 1 as it retains the flexibility of the DWGM and extends these to end users in Brisbane. However, the end users within the Adelaide and Sydney STTM hubs lose the flexibility of operation and lose transparency in balancing. Price discovery is not enhanced although there might be increased price transparency in the new northern hub. Issues with pipeline capacity trading,	MEU, pp. 15-16.	See sections 5.2 and 5.3. The recommended entry-exit virtual hubs are materially different in character to the existing DWGM virtual hub on the DTS.

Issue raised	Stakeholder	AEMC response
augmentation, hoarding, etc, are not addressed, even implicitly, except for the new northern hub where presumably the new hub would operate like the DWGM using entry/exit pricing.		
Origin questions the practicality of virtual hubs on the east coast (notwithstanding the Victorian DWGM), and at this point is unconvinced that the broad adoption of this model would provide a viable means of fostering market development and efficiency.	Origin Energy, p. 2,	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3. Application of these concepts to the Southern and Northern Hubs are discussed in Chapter 5.
Qenos considers that the northern hub should include Moomba. To enhance liquidity, Qenos consider that this option requires pipeline capacity trading between the two hubs.	Qenos, p. 3.	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3. The eventual size of the Northern Hub and the role of Moomba is discussed in section 5.3.
QGC consider it is a logical step change to create a single Wallumbilla/RBP hub for a number of other reasons: (1) it would reduce the transactional costs imposed on participants at the Brisbane STTM; (2) the Brisbane STTM is serviced by a single pipeline from Wallumbilla; and (3) the regulatory changes required to create the virtual hub are likely to be relatively less complex as RBP is a regulated pipeline. This concept is unlikely to generate additional liquidity and a creditable reference price being established at any one trading location (insufficient buyers and sellers). It also contemplates the inclusion of a GSH at Moomba in order to provide an alternative centralised exchange for participants (particularly southern players) to trade gas. There are, however, a range of factors that require more detailed consideration in order to demonstrate that establishing a separate pricing point at Moomba is the optimal short and / or long term solution for the east coast gas market.	QGC, pp. 4-5.	The Commission's consideration of the Northern Hub is outlined in section 5.3, in which it initially recommends the continued development and implementation of the Optional Hub Services model at Wallumbilla, together with improvements the contract carriage model for pipeline capacity, outlined in Chapter 4. If the recommended initiatives to facilitate the trading of hub services and pipeline capacity proved ineffective at promoting gas market liquidity at Wallumbilla, the Commission considers that there would be a case for expanding the hub either over the full Wallumbilla compound or more widely over pipelines in south-east and/or south-west Queensland.

Issue raised	Stakeholder	AEMC response
Santos considers that a virtual hub design would require significant changes to the pipeline capacity market and there are questions whether there is sufficient pipeline capacity to enable the ready movement of gas around large virtual hubs through the entry and exit model.	Santos, p. 4.	As noted in section 3.2.3, a main drawback of a virtual hub compared to a physical hub is that, because of the lack of locational signals, there is a need to manage gas flows within the hub, which can result in higher costs that may largely have to be smeared across hub users or in the amount of long term capacity rights being reduced. This is a key consideration when designing the size of a virtual hub as this issue become more pronounced for larger virtual hubs which contain physical constraints. The Commission considers that the DTS meets the criteria for virtual hubs set out in section 3.3, and that the costs of managing gas flows would not outweigh the benefits of a virtual hub at that location. If the recommended initiatives to facilitate the trading of hub services and pipeline capacity proved ineffective at promoting gas market liquidity at Wallumbilla, the Commission considers that there would be a case for expanding the hub either over the full Wallumbilla compound or more widely over pipelines in south-east and/or south-west Queensland. In this case, consideration of the management of gas flows within the hub would inform the hub’s size and location.
Stanwell states that it is unclear how this concept could operate without the inclusion of the Moomba supply centre.	Stanwell, p. 8.	The Commission's consideration of the Northern Hub, including Moomba, is outlined in section 5.3.
Stanwell considers that virtual hubs require complex entry and exit tariffs. Stanwell state that virtual hubs require the pipeline transport system to act like a large vessel with one charge to 'enter' the vessel and another separate charge to 'exit'. Because the tariff conceals the distance between the gas source and the customer, efficient distance-based price signals are obscured.	Stanwell, p. 2.	Section 5.3 outlines the entry-exit model proposed by the Commission.

Issue raised	Stakeholder	AEMC response
Stanwell consider that virtual hubs do not allow for both standard and bespoke products, whereas physical hubs do. Stanwell state that the trade if standard and bespoke products can be achieved by voluntary markets for liquid standardised (ie. exchange traded) products in conjunction with bilaterally negotiated agreements for non-standard products.	Stanwell, p. 3.	The establishment of exchange-based trading allows for innovation in products offered and for standardised products to emerge (eg, day-ahead products, monthly products, winter 2020 products etc) and participants will determine the success of individual products – that is, products will be traded only to the extent that they are useful to participants. In well-established commodity markets, financial derivatives generally reference the price in the most liquid of these products. See section 5.2.
Stanwell consider that virtual hubs are not readily scalable, whereas physical hubs are. For example, if the proposed Northern Territory gas pipeline eventuates, a physical hub could be set up at the interconnection between this pipeline and the existing pipeline network. However, under a virtual hub arrangement, the hub would need to be reconfigured to incorporate the new pipeline with probable changes to entry and exit tariffs around the node.	Stanwell, p. 3.	While not explicitly part of the Northern Hub, a second GSH at Moomba will be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba could establish itself as a transit point for gas flowing between the east coast markets, particularly if the proposed pipeline from the Northern Territory into the east coast market is completed. See sections 5.3 and 5.5.1.
Visy are concerned about the risk and challenge associated with conversion to virtual hubs and whether the creation of particular hubs will in fact improve liquidity and properly address the Vision.	Visy, p. 3.	Sections 5.3 and 5.4 outline the Commission's view on how the proposed recommendations, including a virtual hub in Victoria, are expected to promote the Vision. This is also summarised in section 3.3
Ability of Concept 3 to promote the COAG Energy Council Vision		
The implementation of a virtual hub/s across the east coast of Australia (in particular Concept 3) would be a considerable challenge for reasons that include: (1) the virtual hub/s would combine transmission systems with different ownership and operations; (2) the virtual hub model would be a significant change to the operation, investment framework and regulation of pipelines on the east coast; (3) congestion is likely to be a challenge to manage on the geographically large transmission systems. These	AEMO, p. 4.	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3. While the Commission seeks to concentrate trading as much as possible at two hubs, the Commission does not consider that two very large virtual hubs covering most or all of the pipeline system would be likely to be efficient.

Issue raised	Stakeholder	AEMC response
constraints may not be observable today as traders generally transport gas along a specific commercial path and operate within the bounds of their contractual arrangements; (4) the inclusion of some facilities and not others could impact on trading and balancing outcomes. For example, if participation costs are high then trading may be conducted away from the virtual hub which would undermine the goal of focussing wholesale trading at the hub.		Over the majority of the east coast of Australia, the geographically distant nature of production and demand centres, with long, point-to-point pipelines, means that there would be significant costs associated with virtual hubs in terms of less precise investment signals and reduced competition to provide additional pipeline capacity. Efficient investment outcomes form a very important part of the NGO, when assessing long term benefits to consumers. Consequently, under the Commission's recommended roadmap, the majority of pipelines would continue to operate a contract carriage regime, similar to that which currently exists.
AEMO agrees that enlarged hubs are a good idea, though only to the extent that the scale does not undermine their goal. Constraints within the proposed hubs are likely to be a challenge to the virtual hub model. The proposed hubs cover a large geographical area and combine multiple pipeline transmission systems – constraints between these systems could impact on the markets ability to match traders operating at different locations within the hub. It is possible that the size of these hubs may make it difficult to maintain a virtual trading point given the level of constraints. Some socialisation of costs are likely to be associated with funding the cost of alleviating congestion if commodity deals are settled at a single price. A further challenge to the establishment of such large hubs is that they combine transmission pipelines that are currently owned and operated by different entities, cross multiple jurisdictions and are governed by different pipeline regulations.	AEMO, p. 9.	
AGL supports further consideration of Concepts 2 and 3 – the virtual trading hub models, noting that further analysis, including cost/benefit assessments, will provide further clarity on their merit. AGL notes that consideration of the	AGL, attachment 1, p. 2.	As set out in Chapters 4 and 6, development of the Commission's recommended Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access to enable the ready movement of gas on the east coast.

Issue raised	Stakeholder	AEMC response
virtual hub models must take place concurrently, and with regards to, the AEMC's work on pipeline capacity trading.		The Commission is undertaking further work to understand the costs and likely benefits of implementing the reforms proposed and will present these findings in our final report.
Concept 3 appears to require the revocation of existing greenfields exemptions in place for the LNG pipelines which are scheduled to run for 15 years, as this model will require economic regulation and changes to existing contractual arrangements to create entry/exit rights.	APA, p. 18.	Consideration relevant to the detailed design work involved with implementation are outlined in Chapter 7.
APLNG supports Concept 2 but notes that as the market matures, the goal could be to implement Concept 3.	APLNG, p. 2.	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3.
EnergyAustralia consider that Concept 3 will allow for a harmonised gas scheduling process but the benefits of this are unlikely to outweigh the reform costs. EnergyAustralia consider that simpler reforms may still offer significant albeit imperfect improvements to allocative efficiency and that cross-jurisdictional issues may also provide a barrier to national reform.	EnergyAustralia, p. 3.	
GDFSAE is less supportive of this model than Concept 1 as it does not provide sufficient granularity in terms of location signals for new investment. Concept 3 is not feasible (at least in the medium term), as it would require substantial regulatory change to many pipelines, and require significant hub services to be established. Concept 3 is not favoured as it would require complex regulatory changes including how to incorporate a mixture of market and contract carriage pipelines. Locational signals would be all but lost, and service costs to facilitate such large virtual hubs would be prohibitive. These issues would also introduce new and unmanageable risks for participants which would act as disincentives for market participation.	GDFSAE, pp. 3-4.	

Issue raised	Stakeholder	AEMC response
The creation of two large virtual hubs covering the east coast would represent a significant change from current arrangements. It would effectively require the implementation of market carriage transportation arrangements across the entire east coast and therefore significant and complex regulatory intervention. As noted in the Discussion Paper, consideration would need to be given to infrastructure investment incentives and how infrastructure investment (e.g. gas processing, pipelines, storage facilities) would occur under this framework.	ESAA, p. 4.	The Commission highlights that in international terms, market carriage transportation arrangements are an unusual form of virtual hub. The Commission is recommending enhancing the existing DTS arrangements by introducing a system of entry and exit capacity rights to replace the existing system of limited transportation rights in the market carriage arrangements. The Commission notes that some locational signals could be provided under an entry-exit system, ie, for those at entry and exit points to each system.
Hydro Tasmania supports further analysis of Concept 3 and requests the AEMC to continue the investigation by completing a comprehensive and competitive cost-benefit analysis to better understand the optimal structure.	Hydro Tasmania, p. 1.	While the Commission seeks to concentrate trading as much as possible at two hubs, the Commission does not consider that two very large virtual hubs covering most or all of the pipeline system would be likely to be efficient given doing so only adds a small number of additional participants to each hub but results in investment signals being lost on large portions of the pipeline system. See section 3.4.
The MEU state there is no clarity as to whether the two virtual hubs will be operated as gross or net pools. If bilateral trading between production and users is allowed to continue, then the reference price will still be "at the margin" and still reflect the cost of balancing.	MEU, p. 7.	The Commission considers that two reference prices - and so two trading hubs - are likely to best strike a balance between the benefits of concentrating trading and having prices that are meaningful. These two prices would seek to reflect market conditions in the two regions which have both significant sources of supply and demand. In addition, exchange-based trading means that observed prices reflect the underlying value of gas to participants on the east coast. See section 3.4 and Chapter 5.
On balance, the MEU considers that Concept 3 presents a preferred option for consumers of the three concepts proposed, although it must be stated that the limited detail provided on the three options makes a categorical preference somewhat difficult. The MEU considers that this option has the potential to deliver a better outcome for all	MEU, pp. 16-17.	While the Commission seeks to concentrate trading as much as possible at two hubs, the Commission does not consider that two very large virtual hubs covering most or all of the pipeline system would be likely to be efficient. See section 3.4.

Issue raised	Stakeholder	AEMC response
consumers than the status quo but this would have to be demonstrated during the development of the detail.		
Qenos considers that this concept offers benefits over the other two. It would reduce the requirement for complementary transportation agreements to be in place and a simpler entry-exit model would further simplify purchasing. Qenos would be interested in understanding how this could actually work.	Qenos, pp. 3 & 5.	
QGC views a concept similar to this as the preferable longer-term market model for the east coast (ie, a potential ten year target for the market). It encompasses the broadest set of potential buyers and sellers and so has the most potential to maximise trading liquidity in each hub so as to foster the development of a credible reference price. However, at this stage, it represents a significant departure from the status quo and presents a wide ranging set of complexities (such as entry/exist pricing) that would take time to progress. As such it is unlikely it could be implemented, in full, over the near term.	QGC, p. 6.	
Stanwell considers this concept is an exceptional change to the design of the market and would take years to fully implement given the existing property rights. Stanwell state that it is unclear how it is superior to either of the other options.	Stanwell, p. 8.	
Origin questions the practicality of virtual hubs on the east coast (notwithstanding the Victorian DWGM), and at this point is unconvinced that the broad adoption of this model would provide a viable means of fostering market development and efficiency.	Origin Energy, p. 2.	The advantages and disadvantages of the virtual hub concepts are discussed in detail in Chapter 3.

Issue raised	Stakeholder	AEMC response
Additional concepts considered to promote the COAG Energy Council Vision		
GDFSAE suggests that multiple gas market zones could be established to provide locational pricing signals as is done in the NEM. The gas balance at each zone as well as the movement of gas between the zones would be centrally scheduled by a single gas scheduling engine with an objective of overall optimisation subject to physical constraints.	GDFSAE, p. 4.	Zonal pricing with capacity rights establishes multiple pricing zones and introduces capacity rights between the zones, which would provide a market determined price for usage of the system by users without such rights, and therefore a signal for investment. As the capacity rights relate only to inter-zonal congestion, the market-led signals would only drive investment between zones – a separate process would be required to govern investment within zones. The Commission considers that this does not obviously establish better preconditions for supporting market-led investment than the entry exit model and results in a significant increase in complexity and transaction costs for market participants. A system of zonal pricing is also currently untested in gas markets internationally, as far as the Commission is aware. See Appendix B of the Stage 2 Draft Report for the DWGM Review.
QGC proposes a fourth concept that would allow participants to trade natural gas at a virtual central hub (incorporating Wallumbilla and the SWQP). The proposed Southern Hub would still exist along with a new physical trading point at Gladstone. QGC consider that it could be implemented more simply than Concept 3, while still capturing the major production and demand elements of the east coast markets (ie, represents a broader set of the market participants (and gas flows) than currently exists at Wallumbilla GSH). QGC's view is that the proposed coverage of buyers and sellers is likely to create a market with sufficient depth to underpin the establishment of a credible reference price. QGC note that it has previously suggested an alternative	QGC, pp. 7-8.	The Commission considers that including SWQP in the northern hub would add very few participants, and hence, liquidity to the northern hub and would result in lost investment signals along a significant stretch of pipelines. The Commission also understands that the SWQP is likely to become congested in the future and so challenges will arise associated with scheduling flows. In addition, the Commission considers that any concerns participants have with accessing SWQP more broadly will be addressed as part of the mechanisms introduced to facilitate trade in pipeline capacity markets.

Issue raised	Stakeholder	AEMC response
model where Moomba would be considered a receipt point for the Wallumbilla GSH. Under this model, trades would be based off the Wallumbilla price ex-transport. While, implementation would require a number of issues to be worked through, this could be examined as an intermediate step towards the creation of a central hub. QGC consider that entry and exit arrangements would need to be established, which involves consideration of how these are best applied to the SWQP as an “uncovered” pipeline (and whether any regulation is necessary).		
Visy proposes an option that retains the STTM hubs and DWGM, develops trading hubs at key physical points in the east coast (Moomba, Sydney, Longford and Iona) and introduces tools to address pipeline capacity unavailability. Visy state that this option is similar to Concept 1 but with the important caveat that STTMs and DWGM should retain their status a full spot markets without being scaled back to balancing-only.	Visy, pp. 6-9.	As outlined in Chapter 5, the Commission is recommending that the STTM hubs remain in place until liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading. The Commission recommends that the STTMs are then pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTMs have provided in recent times.
Trading of pipeline capacity and supporting information		
It is important that the following arrangements are in place to achieve a liquid wholesale gas market: (1) effective pipeline capacity trading arrangements; (2) efficient pipeline and storage services to support short term trading; (3) competitive and efficient hub services to pool together traders and concentrate liquidity; (4) harmonisation of participant interfaces to wholesale gas markets; and (5) enhance gas market information. In particular, it is important to increase transparency for the sections of the network that are overlayed with wholesale gas markets.	AEMO, p. 3.	As set out in Chapters 4 and 6, development of the Commission's recommended Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access and information provision. In this respect, the package developed by the Commission is a congruent set of inter-related recommendations that mutually reinforce the objectives of each another. The Commission's recommendations regarding pipeline access cover: contracted but un-nominated capacity auction; capacity trading platform with standardisation of capacity; and primary capacity information transparency. The Commission's

Issue raised	Stakeholder	AEMC response
AGL notes that consideration of the virtual hub models must take place concurrently, and with regards to, the AEMC's work on pipeline capacity trading. Accordingly, AGL reserves judgement on the various virtual market concepts proposed until further analysis is undertaken.	AGL, p. 1.	recommendations regarding information provision include: broadening the purpose of the Bulletin Board in the NGR; expanding the scope and coverage of the Bulletin Board; and improving the reporting and compliance framework. These are covered in Chapters 4 and 6, respectively. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTMs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTMs have provided in recent times.
APA considers that the east coast has achieved pipeline capacity trading on market terms, and development of secondary pipeline capacity markets is well on its way. APA notes that previously agreed reforms, such as increased and better information provision to support capacity trading, have not yet been implemented.	APA, p. 20.	
While the ESAA maintains an incremental approach to reform that has appropriate regard for existing contracts is the best approach to facilitating trading, the outcomes of the AEMC's assessment of potential measures to better facilitate pipeline capacity trading is highly relevant to the development of a long term market reform strategy.	ESAA, p. 2-3.	
The MEU considers that there is an inability to trade capacity of pipelines from those with unused capacity to those seeking capacity. The MEU states that this is a desirable feature and requires the introduction of a capacity trading market, particularly in the STTM.	MEU, p. 10.	
Origin appreciates there is a separate workstream on pipeline capacity trading but we suggest it is difficult to consider market design and in particular, the three high-level concepts in isolation of pipeline access and regulatory arrangements as the two are inextricably linked.	Origin Energy, p. 2.	
Qenos consider that the main barrier to achieving a liquid market is the lack of access to transportation from the hubs to demand centres.	Qenos, p. 4.	

Issue raised	Stakeholder	AEMC response
Santos consider that a major impediment to liquidity is the ability to transport gas to and from a desired destination, which in turn reflects the nature of the transmission pipeline regime across Eastern Australia. Santos consider that hubs in the US and UK have developed to be liquid trading hubs because they have evolved from the unique set of market conditions, demand and historic infrastructure, although neither are a natural fit for the Australian market without knowing what changes are proposed to the pipeline capacity market, these pipeline reforms really are the missing link that is required before a recommendation on the market design can be determined.	Santos, pp. 3-4.	
Stanwell considers that a transparent and competitive market in the resale of rights to use pipeline capacity is optimal for the east coast. Stanwell state that when setting tariffs, the AER could also authorise highly specific, point-to-point capacity rights in order to create a secondary market in pipeline capacity (these capacity rights could be segmented to cover the gas network between logical pipeline "break points").	Stanwell, pp. 1-2.	
Addressing the fundamental issue of bringing unutilised short term pipeline capacity to market is likely to remove the need to introduce or prescribe alternative physical or virtual trading hubs. With a more open and efficiently priced short term pipeline capacity trading environment, gas trading locations will naturally evolve at locations where buyers and sellers consider it best suits their needs.	QGC, p. 2.	In the United States, having many physical hubs across the network has been a successful model due to the large number of trading market participants - larger than any other country. Markets at individual physical hubs grow and contract in the United States depending on their level of use over time. This is unlikely to be a realistic approach in Australia, where the market is much more concentrated. If no individual trading point on the east coast emerges to become the benchmark hub, then the benefits of a liquid wholesale gas market will not flow through to consumers.
The establishment of an entry/exit model will not, per se, solve the problem of pipeline capacity scarcity which is a	Visy, p. 3.	The Commission also notes that, since parties only require rights to enter and exit the DTS under the recommended design, these rights represent more homogenous and fungible products than the

Issue raised	Stakeholder	AEMC response
key concern for the east coast of Australia. Visy state that many pipelines on the east coast are fully contracted and that this is a strong barrier to entry for parties unless capacity trading is effective. Visy also notes, from an anecdotal perspective, there appears to be a large degree of capacity hoarding by particular shippers on particular pipelines, which also forms a barrier to entry to pipeline access by new entrants and end users.		point to point rights under Concept 1 and so are likely to be easier to trade.
To maximise the benefit of supply hubs, and more generally to enable gas to flow to where it is most valued within the interconnected east coast gas market, a transparent mechanism is required to enable the trading of short term pipeline transportation capacity.	ERM, p. 5.	The Commission agrees that the trading of short term pipeline capacity is particularly important to support liquid trading of gas that reflects short term changes in supply and demand. The Commission is consequently recommending that contracted but un-nominated capacity be auctioned on a day-ahead basis.
EnergyAustralia consider that voluntary balancing only arrangements at demand hubs such as suggested in Concepts 1 and 2 could result in a more opaque market as much of the pricing and portfolio information provided currently would not be available.	EnergyAustralia, p. 3.	The Commission notes this but considers that the Energy Council's Vision would be best met by focussing trade at two points on the east coast: in the north by continuing to evolve the existing Wallumbilla GSH and in the south at a virtual hub covering the Victorian DTS. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times.

Issue raised	Stakeholder	AEMC response
Concerns about market depth and concentration on the east coast		
APA is concerned with market depth on the east coast. Regardless of the number of market participants and the volume of gas traded among them, there will remain three or four very large participants that control up to 80% of the market's gas. A single large participant moving from "buy" to "sell" (or vice-versa) could significantly move the market. In this environment, APA believes it is unlikely that sufficient confidence will develop in a market price as a reference to support a liquid wholesale gas market.	APA, p. 3.	Chapter 2 examines the number and type of participants in the wholesale gas market across the east coast. It shows that the Vision is expected to be achievable, particularly given the transformation that is occurring in the east coast gas market. Chapter 5 outlines how financial derivatives to manage price risk can be expected to be developed over the most liquid of the physical products that emerge at the Northern and Southern Hub.
APA would caution against the temptation to introduce significant changes to the structure of the market without considering the key fundamental issues of market depth and breadth. It would not serve the gas market to undermine existing mechanisms that have served the industry well, such as incentives to invest, through the perceived goal of achieving a liquid market that may not eventuate due to the limited number of large market participants.	APA, pp. 3-4.	
APGA consider that the structure of the Eastern Australian gas market is the major limiting factor to its liquidity. APGA present high-level HHI analysis as suggesting that a level of concentration in production that makes it difficult to develop liquid markets. The level of intervention required to increase the number of participants, address the concentration of market power or increase the volume and/or location of gas demand is almost certain to be too costly.	APGA, pp. 12-15.	
EnergyAustralia are unsure that a liquid derivatives market would develop under any of the concepts proposed, noting that primary sellers of supply and transport are not exposed to the spot price with their liability limited by force majeure and other clauses.	EnergyAustralia, p. 3.	

Issue raised	Stakeholder	AEMC response
ERM concerned that balancing gas regimes end up favouring the larger players and result in disproportionate costs and unmanageable risks imposed on smaller participants. ERM points to the industry structure at each of the demand hubs, where one or two players dominate (for instance, AGL is a dominant gas retailer in NSW, Origin in SA and Origin and AGL in Queensland).	ERM, p. 2.	The Commission considers that the system of voluntary trading with market-based balancing does not result in any participants being favoured more than others. In particular, all participants are incentivised to trade with one another to resolve imbalance. This is outlined in section 5.2. More broadly, the Commission's recommendations propose to only pare back the existing STTM hubs once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading.
The MEU considers that there is limited competition and concentration of gas production on the east coast.	MEU, p. 8.	Upstream supply arrangements sit outside of the remit of this review. However, the Commission notes that the ACCC is currently investigating this as part of its concurrent inquiry. See Chapter 2 for discussion of the level of competition on the east coast.
Visy considers that the challenges posed by a high concentration of gas production in very few producers and very few pipeline owners and limited competition must be dealt with. However, provided that participation in these trading hubs remains voluntary, participants will be able to indicate which hubs are most important to them. The worst case is that some hubs have limited activity (whereas others are more active) and that this is much better than status quo where (apart from Wallumbilla which is only emerging, and STTMs which are short term price signals only) there is poor price transparency on the east coast at present.	Visy, p. 2.	
The compulsory or voluntary nature of markets		
APA supports a voluntary market over a compulsory market.	APA, p. 24.	See section 5.2.1.
APGA consider that voluntary hubs are preferable to compulsory hubs as they appropriately allocate the cost of services to the parties that use the services and do not generate 'false liquidity'.	APGA, pp. 9-10 & 12.	

Issue raised	Stakeholder	AEMC response
APGA consider that both virtual hubs and compulsory hubs generate false liquidity, adding costs to participants while delivering limited benefits.	APGA, pp. 7&9.	The Commission recommends a system of 'voluntary trading with market-based balancing' where participants are not forced to make daily bids and offers for gas injections and withdrawals, as per the current DWGM design and STTM hubs. A key benefit of transitioning the DWGM to a system of voluntary trading with market-based balancing is the expected emergence of a reference price that encourages the development of financial derivative products. Such a price allows parties to take equal but opposite positions in the spot and futures market, which will allow participants to effectively manage risk and therefore support growth in liquidity. See section 5.2.1.
ERM considers that the mandatory or voluntary nature of the virtual hub concepts needs to be explored before they can meaningfully comment.	ERM, p. 5.	
GDFSAE assumes that the final design would retain a voluntary option for participants to seek supply of gas from the northern hub, but would also retain the current gross trading of all gas withdrawn from Brisbane. GDFSAE suggests that this combination of voluntary and mandatory trading at a single virtual hub might pose some challenges.	GDFSAE, p. 3.	
Origin considers that the discussion paper is unclear on whether any of the concepts require voluntary or mandatory participation and states that it is important to recognise there are trade-offs between voluntary and mandatory participation.	Origin Energy, p. 2.	
Qenos consider that the experience in the current STTM and gas supply hub has shown that compulsory participation by both shippers and end users is required to maximise market depth and liquidity.	Qenos, p. 1.	
Different gas specifications on the east coast		
AGL considers that some producers may need to invest in processing in order for their gas to be suitable specification for LNG plants. AGL considers this investment is best addressed by producers/the private sector.	AGL, Attachment, p. 3.	The Commission has concerns that differences in gas specification have the potential to limit secondary trading of pipeline capacity and, therefore, trading liquidity. Consequently, gas specification may be a matter to be addressed through the standardisation process. The Commission intends to give further consideration to this issue over the remainder of the review.
APA considers that there are two key problems associated with differing gas specifications in different geographical segments of the market: (1) reduction in liquidity through	APA, p. 11.	

Issue raised	Stakeholder	AEMC response
splitting the market; and (2) barriers to market entry for some gas.		
APGA consider that the differing gas specifications may act as a barrier to trade. Participants with export exposure may refuse to purchase standard specification gas. There is the potential they will insist on further processing. Further processing of gas would be a service that could not meet the production process exemption for coverage under the National Access Regime, opening the door to appropriate oversight of gas processing facilities.	APGA, p. 19.	
Cautious about drawing inferences from overseas markets		
The European system of virtual hubs and entry-exit models was developed and has evolved within the particular context of multiple sovereign member states, vertical integration of transmission businesses and varying levels and sophistication of third party access regulation. APA considers that the European gas market has not developed within the same cohesive National Competition Policy structure as is in place in Australia, where principles of competition, third party access, and vertical disaggregation have been common place for almost 20 years. Further, APA does not consider that it is appropriate to apply a virtual market model, as developed for electricity markets, to gas markets. APA is cautious about drawing conclusions from observations of other markets; there are invariably so many forces in play that it is very difficult to draw causal conclusions from isolated observations. In particular, APA considers that the application of the European market model should not be seen as the panacea to achieve Australia's policy objectives.	APA, p. 14.	The Commission considers that some parallels can be drawn between the broader market environment in Eastern Australia and markets in Europe and the United States. However, the east coast market arguably suffers from the challenges arising in both the US and Europe. Like the US, the transmission network is primarily made up of long, point-to-point pipelines, typically between production centres and far distant demand centres. Consequently, the efficiency of investment is a key concern. However, like many markets in the EU, there are a relatively low number of market participants (although lower barriers may stimulate additional competition). As a result, the ability of virtual hubs to pool liquidity may be of significant benefit. This means that there is not an obvious international precedent to draw on, and that an approach that draws on both models should also be considered. See sections 3.2.3 and 3.3.

Issue raised	Stakeholder	AEMC response
Entry-exit, as is in Europe, requires that a shipper must independently (and simultaneously) win two auctions: to enter system 1, and to exit system 1/enter system 2. A failure to win either of these auctions will result in a failure to deliver. APA considers this could be a concern in either of the AEMC's virtual market models.	APA, p. 21.	
APGA considers detailed comparisons between international gas markets and the Australian gas market are of little value.	APGA, p. 14.	
The ESAA considers that, unlike the NBP TTF and Henry Hub, the east coast gas market is characterised by a relatively low number of market participants, low annual consumption and long point to point transmission pipeline connections. Long term bilateral agreements for gas supply and transportation are also a prominent feature of the east coast gas market given the capital intensive nature of gas production/transportation. Collectively these factors may provide a barrier to increasing trading and liquidity on the east coast, particularly where the risks of trading cannot be effectively hedged.	ESAA, p. 3.	
The long-distance transportation nature of the east coast may render it not cost-effective to develop large virtual hubs like in Europe. The US market demonstrates that the development of market liquidity is based on a number of other factors, as well as the existence of short term trading markets. These other factors include transportation access, underlying physical market volumes, the number of buyers and sellers and availability of gas storage.	Esso, p. 1.	
Origin cautions against a simplistic view that the Australian gas market should strive to replicate overseas models as there are marked differences between the Australian market and these markets. These include that the east coast gas	Origin Energy, p. 1	

Issue raised	Stakeholder	AEMC response
market is characterised by lower levels of consumption, fewer market participants and different pipeline arrangements.		
The European and US wholesale gas markets are very different to Eastern Australia's in population, number of demand centres, distance and pipeline infrastructure to name a few. However these differences are often overlooked in discussions of the benefits of their respective wholesale gas market designs. These markets can, and should be, used as a reference point, but the Australian local conditions will often mean that they cannot be directly replicated, or not without significant cost.	Santos, p. 1.	
Virtual hubs require complex entry and exit tariffs that conceal the distance between the gas source and the customer and obscures efficient distance-based price signals. The entry/exit regime is also hindering efficient market outcomes in the European market.	Stanwell, pp. 2-3.	
Visy struggles to support deployment of virtual hubs based on apparent successful operation in other jurisdictions with meshed systems and would need to see a lot more detail in terms of the advantages in an east coast Australia context to be convinced.	Visy, p. 3.	
Cautious to undertake reform at this point in time		
AGL considers that the AEMC should exercise caution in recommending changes to a market that is in transition.	AGL, p. 1.	The Commission has presented an overview of the case for change in Chapter 2. In particular, industry participants are likely to require more flexible and sophisticated ways of managing their gas portfolios going forward. This will likely be due to: • rising gas supply agreement (GSA) contract prices, inducing participants to reduce their average gas supply costs through market-based trading;
APA strongly recommends that the existing Wallumbilla Gas Supply Hub be given the opportunity to develop and flourish in response to demonstrated industry needs before being replaced by a costly market design founded on assumed future needs.	APA, p. 5.	

Issue raised	Stakeholder	AEMC response
Stanwell consider it may be unwise to fundamentally redesign a market which has proven robust to the development and initial commissioning of a large LNG industry.	Stanwell, p. 8.	• reduced load factor flexibility in GSAs and/or flexibility priced at a premium, providing an incentive to utilise trading markets to procure flexibility; and • spot price volatility, resulting in arbitrage opportunities that participants seek to benefit from. In the Commission's view, these factors highlight the importance of achieving the COAG Energy Council's Vision. Achieving the Vision will provide participants with greater flexibility when buying and selling gas, and should promote an increase in wholesale market competition. Competition facilitates the process by which gas is allocated to those users who value it the most, promoting efficient wholesale market outcomes that benefit consumers through lower retail prices.
Other comments		
AGL considers that gas transportation and supply arrangements that are sufficiently flexible to meet short term changes in supply and demand profiles should be the underlying driver of any policy reform proposals.	AGL, Attachment 1, p. 1.	While supply arrangements sit outside of the remit of this review, as set out in Chapters 4 and 6, development of the Commission's recommended Northern and Southern Hubs is supported by equally important recommendations to enhance pipeline access, including over the short term.
The extent of legislative change to Australia's competition policy framework and the imposition of regulatory oversight required to create virtual markets should not be underestimated.	APA, pp. 16-17.	Uniquely, in Victoria the introduction of an entry-exit model would represent an evolutionary step and therefore the benefits of such a virtual hub could be realised with much lower (although still material) implementation costs. While the Commission considers there would also be benefits associated with implementing such a model in the Northern Hub, it considers that there are greater costs at this stage and that it would be substantially more difficult to implement.
APA considers that a virtual market model will necessarily involve disruption of existing contractual rights. In addition to the costs involved in dissolving these contracts, APA consider the AEMC should consider the impacts on business confidence that could arise where contracts are displaced by government policy.	APA, p. 17.	

Issue raised	Stakeholder	AEMC response
APA believes that managing and honouring existing contractual rights is more than a transitional issue, and the direct costs of resolution are likely to exceed benefits derived from a change to virtual markets as unaddressed market structure limitations and the effect on investment incentives from such markets will be further barriers to market liquidity.		
APGA consider that virtual hubs are likely to require regulatory intervention into existing commercial arrangements.	APGA, pp. 10-12.	
ERM would not support a removal of the DWGM or STTM, or any change to these markets to make them voluntary and/or solely balancing regimes.	ERM, p. 2.	The Commission's recommended design for the Southern Hub retains the certainty of delivery provided by the DWGM. In addition, once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still preserving the flexibility the STTM hubs have provided in recent times. See sections 5.2 & 5.3.
ERM consider that information about physical market conditions should be made available on a much wider and real time basis and captured in a single location (the Bulletin Board). Unplanned pipeline and production facility constraints should be reported as soon as they occur (consistent with the NEM).	ERM, p. 3.	The Commission has considered the potential for moving to real time reporting. At this time, the Commission considers that the benefits of moving to this type of report are likely to outweigh the costs but that these benefits may increase in the future. The Commission recommends that the frequency with which information is reported and alerted to market participants should be improved by requiring any material changes to a Bulletin Board facility's capacity during a gas day to be reported as soon as practicable on that day. This information, along with updates to pipeline nominations should be displayed prominently on the Bulletin Board. See Chapter 6 and the supplementary report on information provision which accompanies this paper.

Issue raised	Stakeholder	AEMC response
Clarification is needed as to how the AEMC east coast gas market review, DWGM review, AEMO's work in developing the Wallumbilla Gas Supply Hub and the ACCC East Coast Gas inquiry will tie together. ERM considers that there appears to be overlap in areas and are unclear about how any inconsistent findings will be addressed.	ERM, p. 6.	The DWGM Review considers the Victorian gas industry in greater detail than the East Coast Review and makes recommendations that would only initially be applied to the DTS. Consequently, these matters are presented in a separate, complementary report that focuses specifically on the DWGM review. The Commission is working closely with the ACCC and there is the ability for the ACCC to share information with the Commission. Further, we currently intend to provide the final report for this review and the DWGM Review to the Energy Council in May 2016 so that they are able to reflect the ACCC's findings. Throughout East Coast Review, the Commission has also been working closely with AEMO as it develops its recommendations regarding a single trading product for Wallumbilla.
Esso considers that eastern Australia could achieve an increased level of short term trading and liquidity over time with the right supporting policies, but that long term bilateral contracts will remain a key component of the market place.	Esso, p. 1.	The Commission agrees that bilateral gas contracts continue to play a role in liquid wholesale gas markets going forward.
GDFSAE suggest that in considering the three concepts, there is an important trade-off to be considered between achieving greater liquidity (through larger virtual hubs), and ensuring effective locational signals for investment and trade (through localised physical hubs or concentrated virtual hubs. Another important general consideration is that reducing the complexity and risk of facilitated markets is likely to improve participation and promote market liquidity.	GDFSAE, p. 2.	The Commission agrees with these considerations and has explicitly considered these in its assessment. See section 3.2.3.
GDFSAE considers that "trade is focused at a point that best serves the needs of participants" should be an explicit criteria assessed by the AEMC.	GDFSAE, pp. 2-3.	

Issue raised	Stakeholder	AEMC response
QGC identified that establishment of “within-day” trading flexibility is essential to allow further balancing (due to the swings in LNG production), increased liquidity and the overall development of a well-functioning east coast gas market. QGC expects that this issue would also be considered through this work stream and in do so examine the impediments to and options for creating a viable intraday gas market.	QGC, p. 9.	The Commission recommends the use of exchange based trading at the Northern and Southern Hubs. Exchange based trading provides participants with greater flexibility in how they buy and sell gas than the current reverse auction mechanism currently. Exchange trading allows for innovation in products, eg, within-day products.
Santos considers that all options will require an assessment of the collective costs and benefits. Santos also notes that participants may have a valid claim to compensation - especially if any reform results in a change away from the current contract carriage access to a more regulated, open access framework.	Santos, p. 2.	We are undertaking further work to understand the costs and likely benefits of implementing the reforms proposed and will present these findings in our final report. Analysing the likely costs and benefits of reform of this nature is inherently complex and in some cases is poorly suited to quantitative assessment – either because such assessment is not possible or because the it exhibit a large degree of uncertainty. The Commission therefore considers that such an assessment is best done through a combination of quantitative and qualitative assessment. The Commission will attempt to quantify impacts where it is possible and appropriate to do so – but in some cases, this will not be the case or the quantification may exhibit a large degree of uncertainty. See Chapter 7.