REVIEW

Australian Energy Market Commission

WHOLESALE GAS MARKETS DISCUSSION PAPER

East Coast Wholesale Gas Markets and Pipeline Frameworks Review

6 August 2015

Submissions due 10 September 2015. Reference: GPR0003
Wholesale Gas Markets Discussion Paper

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: GPR0003

Citation

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

About the AEMC

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

Foreword

The east coast gas industry is attracting the most amount of interest since its inception in the late 1960s. From an industry built on the basis of long term contracts and a conservative risk profile, participants are having to adapt to a growing liquefied natural gas (LNG) export industry three times the size of the domestic market.

The size of the LNG demand, as well as the variable nature of the coal seam gas wells supplying the LNG production facilities, is expected to result in participants managing their gas portfolios more actively than in the past through short term trading. Greater shorter term trading of gas will require physical markets that can foster liquidity and support the emergence of risk management products.

While natural gas is growing in importance to the Australian economy, some domestic gas users are facing difficulties negotiating new gas contracts during this transitional period. In the Commission's view, this highlights the importance of achieving the COAG Energy Council's Vision of a liquid wholesale gas market and providing participants with greater flexibility when buying and selling gas. Trading gas through well-functioning markets is also fundamental to consumers being able to know whether the gas price reflects underlying demand and supply conditions.

As the Commission prepares the Stage 2 Draft Report ahead of the December 2015 Energy Council meeting, this review is an opportunity for gas industry stakeholders to shape the future direction of market development on the east coast. As 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".[1]

In this respect, the objective of this Discussion Paper is to progress the debate on gas market development as we develop our recommendations for the Stage 2 Draft Report. It also provides stakeholders with the opportunity to respond to three high level market design concepts that have been designed to focus the debate on key elements of gas market design. It is important to note that these concepts do not represent a preferred approach, but have instead been designed to engender discussion.

Over the next few months the Commission will be seeking input from industry on a number of workstreams associated with this review. We appreciate the time and resources required to attend meetings and prepare submissions, particularly over such a short timeframe, and thank stakeholders for engaging with the Commission throughout the review process.

John Pierce

Chairman

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

Contents

1 Executive summary

The objective of this paper is to continue to progress the debate on gas market development and how best to meet the Council of Australian Governments' Energy Council Vision for Australia's future gas market. Publishing this Discussion Paper provides stakeholders with an opportunity to provide feedback leading into the Commission's Stage 2 Draft Report, which is due to be considered by Energy Ministers at the December 2015 Energy Council meeting.

As part of the terms of reference for this review, the Commission is required to consider the number and type of facilitated markets on the east coast, taking into account the current arrangements and changing gas market conditions. Facilitated markets operate at gas hubs, which are defined locations on a pipeline system where the transfer of ownership and pricing of gas takes place. Physical hubs represent the transfer and pricing of gas at a specific location on the pipeline system, while virtual hubs encompass a large segment, or all, of a pipeline system.

Physical hubs provide strong locational signals on the price of gas at a specific point in the system. However, multiple physical hubs, and the need to source pipeline capacity to transport gas to and from the hub location, can have a negative impact on liquidity. Virtual hubs on the other hand allow for title transfer of gas anywhere within the definition of the hub, thereby providing participants with greater trading flexibility and help promote liquidity. Virtual hubs typically require a system for allocating transmission capacity into and out of the hub area, such as an 'entry-exit model' where users book capacity rights independently at entry and exit points.

Three high level market design concepts have been developed as a way of seeking targeted feedback from stakeholders on the future development of the east coast gas market. While these concepts have been prepared with the Energy Council's Vision in mind, they have not yet been tested against the assessment framework developed in the Stage 1 Report and do not represent a preferred approach.

The three high level design concepts range from multiple physical hubs to two large virtual hubs across the east coast and are as follows:

- **Concept 1** - Multiple hub locations: Gas Supply Hubs at Wallumbilla, Moomba, Longford, Iona and Gladstone all of which represent physical hubs. Balancing arrangements would be in place at the major demand centres in Adelaide, Brisbane, Melbourne, Sydney and potentially Canberra.

- **Concept 2** - Northern and southern virtual hub, with balancing at Adelaide and Sydney: A new virtual hub in the northern region that encompasses the Roma to Brisbane Pipeline and current Wallumbilla hub (the ‘northern hub’) and a virtual hub in the south covering the Victorian Declared Transmission System (the ‘southern hub’).

- **Concept 3** - Two large virtual hubs covering the east coast: Concept 3 is an extension of Concept 2 and involves the establishment of a northern and southern virtual hub that, together, cover the entire east coast. This approach would not require separate balancing mechanisms at Adelaide and Sydney.

The Commission notes this is not an exhaustive list of options and is interested in understanding stakeholders' views on these and other market design concepts that could meet the Energy Council's Vision.

2 Introduction

The purpose of this paper is to define the concept of a liquid wholesale gas market and set out potential market design concepts that could achieve the Council of Australian Governments' Energy Council Vision (the Vision) for Australia's future gas market, which is as follows:[2]

> "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 focussed 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 Council's Vision can be broken into three key outcomes:

- Establishment of an efficient and transparent reference price for gas.
- Participants able to readily trade gas between hub locations.
- Investment in infrastructure that responds to market signals and is facilitated by a supportive regulatory framework.

The achievement of the Vision requires the creation of a self-reinforcing loop that encourages both the demand and the supply side of the market to participate. Facilitated markets that are simple, low cost and easy to use will encourage participation by producers and users. More participants and greater traded volumes leads to more meaningful pricing signals, giving producers more confidence that they will have a market for their supply. Increased supply gives buyers sufficient confidence to augment their contracts with traded gas from the market. As trading volumes increase, financial risk management tools can be developed, further strengthening confidence in the market.

The ability to buy and sell gas on a facilitated market on an equal basis to other players, and hedge price risk, lowers barriers to entry and promotes competition. This is because, as well as acting as a credible alternative source of gas, the option of using a market will increase the level of competitive tension during gas supply agreement (GSA) negotiations. Trading gas through well-functioning markets is also fundamental to consumers being able to know whether the gas price reflects underlying demand and supply conditions.

---

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

An efficient market-based reference price for gas that is credible in the eyes of participants requires sufficient trading liquidity. Liquidity is commonly defined based on four characteristics:[3]

1. **Market depth**: where no single buy or sell order is likely to move the market price excessively.

2. **Market breadth**: where a large number of bids to purchase gas and offers to sell gas are present in the market.

3. **Immediacy**: the ability to trade large volumes in a short period of time.

4. **Resilience**: the ability of the market to recover towards its natural equilibrium after being exposed to a shock.

In a market with many buyers and sellers, participants should be able to trade confidently knowing that all transactions are occurring at a price that broadly reflects supply and demand, and which cannot be materially moved by the actions of a small number of players. Unless participants are confident that the hub price represents close to 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 a facilitated market or indexing GSAs to a hub price, as the price risk cannot be effectively hedged.

Developing a liquid and credible gas price for the east coast of Australia is not an easy task, particularly given the relatively small number of participants and low volumes consumed compared to markets in Europe and the United States (US). The east coast of Australia is also unique in that the gas market covers a large geographic area with low population density. A question therefore exists as to whether the current approach of multiple hubs at various locations across the east coast gas system can aggregate sufficient volumes of trades to generate a meaningful wholesale gas price, and therefore achieve the Energy Council's Vision.

To progress the debate on gas market development, and to provide stakeholders with the opportunity to provide more focussed feedback leading into the Commission's Stage 2 Draft Report, three high level market design concepts have been developed. These concepts have been put together as a way of seeking feedback from stakeholders and do not represent preferred options.

While the high level market design concepts have been prepared with the Energy Council's Vision in mind, they have not yet been tested against the assessment framework developed during Stage 1 of the review and set out in Appendix A. The assessment framework is structured so that the single overarching objective guiding the Commission is the National Gas Objective, although we will also have regard to other factors, including the Energy Council's Vision and the Gas Market Development Plan.

---

3 IEA 2008, *Development of competitive gas trading in continental Europe – How to achieve workable competition in European gas markets?*, IEA Information Paper, May, p. 46.

The Commission is interested in hearing stakeholders' views and encourages alternative high level market design concepts that could meet the Vision to be put forward through submissions. The remainder of this paper is structured as follows:

- Section 3: Defines a liquid wholesale gas market and sets out how the east coast market could operate in the future;
- Section 4: Discusses the role of a gas hub and defines two different hub designs;
- Section 5: Outlines why physical gas trading takes places;
- Section 6: Sets out why parties trade financial gas products;
- Section 7: Discusses how physical gas imbalances can be managed;
- Section 8: Sets out three high level market design concepts to facilitate stakeholder discussion;
- Section 9: Glossary of terms; and
- Appendix A: Assessment framework.

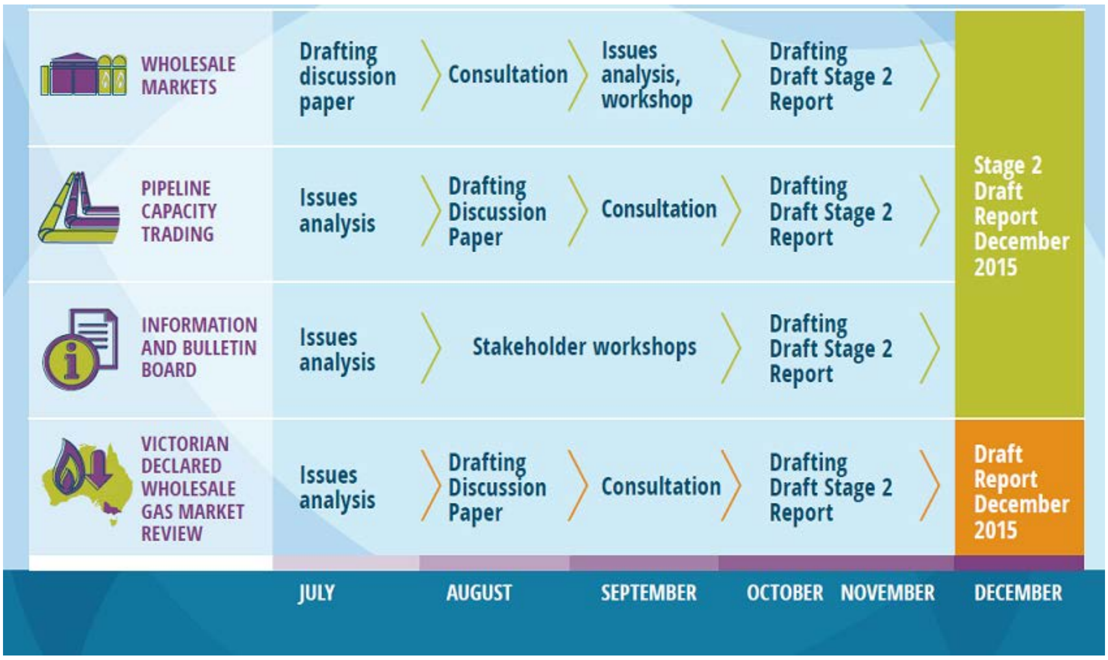
2.1 Next steps in the development of our advice

As outlined in Chapter 3 of the Stage 1 Final Report, there are four workstreams being progressed by the Commission as part of Stage 2 of the review. These are illustrated in Figure 2.1 below. This discussion paper relates to the Wholesale Markets workstream.

Feedback from stakeholders through the consultation process, as well as input from a technical working group that is planned to be convened in September 2015, will inform the Commission's recommendations in the Stage 2 Draft Report. The Commission will also be working closely with the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator throughout all elements of this Stage 2 analysis to draw on their operational and regulatory expertise as we develop our advice.

Work to finalise the Stage 2 Draft Report will commence once the Commission has received direction from the Energy Council at the December 2015 meeting of Energy Ministers.

Figure 2.1 Stage 2 workstreams



2.2 Responding to this paper

The Commission welcomes submissions on any of the issues raised in this discussion paper. In particular, we are interested in stakeholders' views on the following points:

- Over the next 10 years, how do industry participants see their gas sales and procurement activities changing?
- Do the current market arrangements adequately support participants' needs?
- Are gas trading markets expected to become more important in ensuring the efficient allocation of gas?
- How many and what type of wholesale gas trading markets are required to meet the Energy Council's Vision and how should this be assessed?
- Does having multiple gas hubs contribute to or detract from the objective of achieving a liquid wholesale gas market and why?
- What are the main barriers to achieving a liquid wholesale gas market on the east coast and are regulatory solutions required?
- Could the virtual gas hub design concepts set out in section 8 be feasibly implemented on the east coast of Australia? If not, what barriers exist?
- Do existing contractual rights and/or issues around cross border trade preclude any particular gas hub designs?

- Are different gas specifications, such as a higher quality specification for the LNG plants and the odourisation of some transmission pipelines, likely to act as a barrier to trade in the future?

The closing date for submissions is **Thursday, 10 September 2015**.

Submissions should quote project number "GPR0003" and may be lodged online at www.aemc.gov.au or by mail to: Australian Energy Market Commission PO Box A2449 Sydney South NSW 1235.

3 East coast gas market - now and in the future

This section provides an overview of the east coast gas market today, defines the characteristics of a 'liquid wholesale gas market' and discusses what one could look like on the east coast of Australia. Gaps between the current market and the Energy Council's Vision are drawn out through the discussion.

3.1 How the east coast gas market works today

Trade in natural gas and pipeline capacity has predominantly been based on long-term bilateral contracts. In an industry based on capital-intensive assets, particularly an emergent one, contracts are a prudent way to manage risk and secure finance at competitive rates.

The east coast gas market also includes a number of facilitated spot markets. These markets can be characterised as four *physical* gas hubs and one *virtual* gas hub. As discussed in section 4, a gas hub is a location where the transfer of ownership and pricing of physical gas takes place. Physical hubs represent the transfer and pricing of gas at a specific location on the pipeline system, while virtual hubs typically encompass a large segment, or all, of a pipeline system.

There are currently three facilitated gas 'market' designs and five gas hubs on the east coast:

- Short Term Trading Markets (STTMs) in Adelaide, Brisbane and Sydney (broadly physical hubs);
- the Declared Wholesale Gas Market (DWGM) in Victoria (a virtual hub covering the Victorian Declared Transmission System (DTS)); and
- the Gas Supply Hub (GSH) at Wallumbilla (physical hub).

The DWGM and STTM were primarily introduced to support retail competition and as a mechanism to resolve daily gas imbalances in a transparent and competitive way, while the GSH was implemented to facilitate trading close to production centres. Trading of gas on the facilitated markets is generally low and split across these five locations. A sixth gas market could be operational in 2016, with another GSH to be potentially implemented at Moomba.[4]

The STTMs and DWGM are gross pool designs where all gas shipped to and withdrawn from the hubs must be transacted through the markets. The GSH on the other hand is a voluntary market that participants may opt to use to buy and sell gas at the Wallumbilla hub. Prices in the STTM and DWGM are determined by stacking and matching offers with bids in price order once per day and five times per day, respectively. The marginal price determined through this process then applies to all

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

gas transacted through the hub over a defined period. GSH prices are established through matching buy and sell orders, similar to a stock market.

As most gas on the east coast has historically been transacted through bilateral contracts of varying terms, the role of the facilitated markets to date has mostly been to manage daily gas imbalances and to facilitate incremental trading of gas. While bilateral contracting is not necessarily an inhibitor to active gas trading, further participation has likely been limited for two reasons:

- **Stable market dynamic**: The volume and direction of gas flows on the east coast have generally been stable. Participants would sign long-term gas supply and matching transportation agreements with prices generally linked to inflation and, unless an significant event occurred, there was little requirement to actively trade gas on a short term basis.

- **Inability to hedge spot price risk**: Outside of the flexibility that may exist in GSAs (see Box 3.1), market participants have generally not been able to hedge spot price risk in the DWGM or STTM, resulting in exposure to daily price fluctuations. The lack of successful financial risk management products in these markets is partly reflective of the fact that not all of the trading risk is captured in a single commodity price. Due to separate uplift and deviation charges, hedging the commodity price can still expose traders to other price risks.

These factors have meant there has not been a strong requirement to date for very detailed, accurate or timely information on the gas system to assist participants' short term trading decisions. There has also generally not been a strong requirement to procure pipeline capacity at short notice to transport gas to and from hubs in response to movements in the commodity price.

Box 3.1 Managing spot price risk through bilateral contracts

Spot price risk can be physically managed through flexibility in bilateral gas contracts. The ability to manage this risk depends on the specific provisions negotiated into gas supply and transportation agreements, and nomination cut off times set by producers and pipeline operators.[5]

Consider a shipper who is transporting gas to Sydney via the Moomba to Sydney Pipeline (MSP). The shipper may, based on the provisional pricing schedules, decide to purchase five per cent of their gas requirements from the Sydney STTM.

STTM bids and offers are submitted by 12 noon and by 1pm the ex ante price for the following gas day is published. At this point the shipper has two options:

1. If the STTM ex ante price is below the shipper’s delivered contract price, the shipper provides nominations to the producer and pipeline operator for the following gas day to flow 95 per cent of their gas requirements through

5 Shippers nominate gas quantities to their producers and pipeline operators before each gas day.

the MSP, with the remaining five per cent to be purchased on the STTM at the lower price.

2. If the ex ante price turns out to be above the delivered contract price, the shipper would have structured their bids and offers such that the additional five per cent is not purchased on the market, and instead provides nominations to the producer and pipeline operator to flow 100 per cent of their gas requirements for the following gas day.

Managing risk in this way is dependent on the flexibility negotiated in GSAs and gas transportation agreements (GTAs) and nomination cut off times.

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

In January 2015 first LNG cargos were exported from Gladstone, with significant volumes of coal seam gas (CSG) coming online to meet the new demand. First exports represent a historic moment for the east coast gas industry and the market has now entered a transitional period to a new supply/demand balance. Total east coast gas demand is expected to increase from around 690 PJ in 2014 to nearly 2,000 PJ in 2018, driven primarily by LNG production.[6]

Once the LNG trains are fully operational they will consume around 4,400 TJ of natural gas per day on average to meet their contractual obligations, and more if the trains are run at maximum capacity. This compares to average daily consumption on the east coast of around 1,665 TJ per day and to winter peak demand of 2,560 TJ per day.[7] If one of the LNG trains shuts down unexpectedly, and assuming an average turn down rate of 80 per cent for CSG wells, this would leave 125 to 174 TJ per day of gas to be absorbed by the domestic market, equivalent to 6-8.5 per cent of average daily gas demand and storage injection.

The large amount of gas required for LNG exports compared to domestic consumption, combined with the variability inherent in CSG supply, is from time to time likely to result in price differentials across the east coast market. This will provide participants with commercial opportunities to arbitrage gas prices between the facilitated markets as well as between bilateral contract and market prices. Flexibility to trade gas and pipeline capacity at short notice, as well as access gas storage, may also become critical for the security of the gas system.

An example of short term trading during the commissioning of QCLNG Train 1 is discussed in Box 3.2.

6 AEMO, National Gas Forecasting Report 2014.

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

Box 3.2 Commissioning of QCLNG Train 1

In the months leading up to the commissioning of QCLNG Train 1 and loading of the first cargo on 27 December 2014, prices at the Wallumbilla GSH were as low as $0.20/GJ, with the volumes of trades ranging between 2,000 GJ and 40,000 GJ per day.[8]

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

Origin was able to turn down production on its equity gas while purchasing 28 PJ of ramp gas.[9] This allowed the business to take advantage of the relatively cheap ramp gas to supply its customers, while preserving its equity gas for use at a later date. Origin was also able to monetise ramp gas through additional gas-fired generation and business sales.[10]

3.2 What does a liquid wholesale gas market look like?

In a liquid wholesale gas market, gas is physically able to be bought and sold via two means, namely:

- gas can be *contracted* bilaterally between parties (typically for longer durations, bespoke terms and non-transparent pricing) - as is prevalent in Australia; and
- gas can be *traded* among parties (typically for very short-to-medium durations, with variable levels of standardisation and pricing transparency).

As discussed in section 2, liquidity is defined based on market depth, breadth, immediacy and resilience. A liquid trading market is one where a single buy or sell transaction is unlikely to move the market prices substantially, there are a large number of offers to sell gas and bids to buy gas available to participants, trades can be effected quickly for sizeable volumes of gas and the market is sufficiently resilient to recover from demand or supply-side shocks.

For liquidity to emerge on a gas trading market, there needs to be a sufficient number of buyers and sellers willing to trade. Concentration of trading will lead to a wholesale gas reference price that parties trust and which reflects underlying supply and demand. This will in turn encourage more trading, creating a self-reinforcing loop of growing market liquidity. As participants become confident in the trading of physical

8 AER Industry Statistics.

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

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

gas, *financial* products will emerge to hedge physical positions. This can occur via standardised over-the-counter (OTC) contracts through intermediaries, as well as exchange-based platforms like the ASX.

The emergence of financial risk management products will make it more attractive for participants to reference a hub price in bilateral contracts, as the price risk can be effectively hedged. This is likely to make contracting easier and less costly as the time spent negotiating price formulation and escalation mechanisms is reduced.

The concept of liquid wholesale gas market is currently being considered in Europe through the Gas Target Model. The European Agency for the Cooperation of Energy Regulators (ACER) published a series of metrics in January 2015 designed to assess whether a wholesale market is 'well-functioning'. These metrics are grouped into two key characteristics and discussed more fully in Table 3.1:[11]

- meeting of market participants' needs: products and liquidity are available that enable effective management of wholesale market risk; and
- "market health": the wholesale market is demonstrably competitive, resilient and has a high degree of security of supply.

Table 3.1 outlines selected ACER metrics together with threshold values derived from the performance of the National Balancing Point (NBP) in the United Kingdom (UK) and the Title Transfer Facility (TTF) in the Netherlands.[12] We note that churn can also be used as an indicator of liquidity, however, ACER consider this metric is more an indicator of market turnover rather than an objective measure of traded volumes.[13]

Table 3.1 European Gas Target Model metrics for a well-functioning gas market

Metric	Overview
Market participants' needs metrics (day-ahead, 'spot' products)	
Order book volume	Sufficient bid and offer volumes in the order book which deliver gas reasonably far into the future allow market participants to buy and sell gas when they need it and support effective risk management.
Bid-offer spread	Low bid-offer spreads mean low transaction costs for market participants and support market participants who have less flexibility with respect to when they can trade.
Order book price sensitivity	Low order book price sensitivity means less

11 ACER website, available at: http://www.acer.europa.eu/Gas/Gas-Target-Model/Pages/Main.aspx

12 ACER, *European Gas Target Model Review and Update*, January 2015, pp. 21-22.

13 ACER, *European Gas Target Model Review and Update*, January 2015, pp. 23.

Metric	Overview
	additional cost for market participants when buying or selling substantial volumes and supports market participants who have less flexibility with respect to when they can trade.
Number of trades	Sufficient trading activities support market participants' confidence that prices are transparent and represent a reliable market price.
"Market health" metrics	
Herfindahl- Hirschmann Index (HHI)	HHI is a measure of the level of concentration in a market and is often used by competition authorities when investigating mergers or acquisitions. A higher HHI implies a higher concentration.
Residual Supply Index (RSI)	RSI measures the reliance of a market on its largest supplier. The supply capability of all but the largest supplier should amount to 110 % of demand.
Market concentration for bid and offer activities	This measures the market share per company or group of companies based on the bid and offer order volumes placed. Lower market shares support a higher level of competition.
Market concentration for trading activities	This measures the market share per company or group of companies based on the traded volumes. Lower market shares support a higher level of competition.

3.2.1 Physical and financial trading

Figure 3.1 provides a stylised overview of a liquid wholesale gas market in terms of how parties trade gas (both physically and financially) and where these trades take place. The top half of the image represents physical flows, while the bottom half denotes financial flows. As outlined in section 4, a gas 'hub' is defined as a location which includes two or more transmission pipelines that allows buyers and sellers of gas to *transfer* the ownership of physical gas.

Physical flows (red) typically occur in the following manner:

- A producer sells gas through a bilateral contract or at a hub using an exchange or OTC product.
- A gas user buys gas through:
  - a bilateral contract from a producer;
    - consumes that gas; or

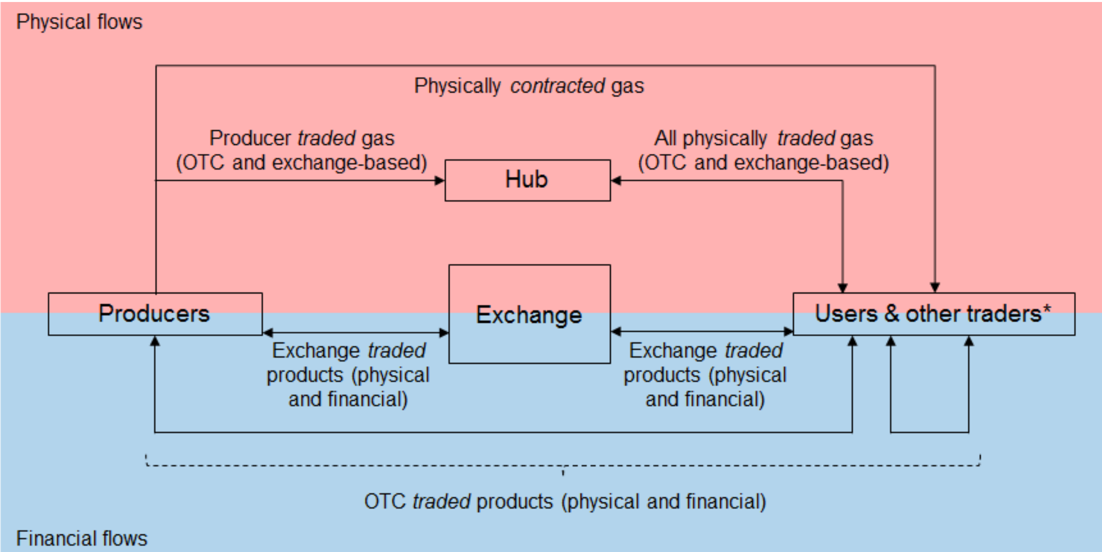
- trades that gas at a hub through an exchange or OTC contract;

– a hub using an exchange or OTC contract.

Financial flows (blue) typically occur as follows:

- A producer buys or sells derivatives on an exchange (such as gas futures or options).
- A producer buys or sells OTC derivatives with a gas user (usually through an intermediary).
- A gas user or trader buys or sells derivatives on an exchange (such as gas futures or options).
- Gas users or traders buy or sell derivatives between themselves via the OTC market.

Figure 3.1 Stylised overview of a liquid wholesale gas market



* Typical wholesale consumers (eg retailers, industrial users and GPG) as well as all other traders (eg, hedge funds, banks, institutional investors, commodity traders etc)

Source: AEMC.

Bilateral gas contracts continue to play a role in liquid wholesale gas markets around the world.[14] Contracts of varying terms are required to underwrite the capital investment in production and pipeline infrastructure, as well as provide volume certainty to buyers and sellers of gas. As the sunk cost of infrastructure is recovered over time, then producers and users of gas may take advantage of flexibility provided through facilitated markets and trade greater volumes of gas on a shorter term basis.

14 Heather, P., *Continental European Gas Hubs: Are they fit for purpose?*, The Oxford Institute for Energy Studies, June 2012, p. 38; IEA, Developing a Natural Gas Trading Hub in Asia - Obstacles and Opportunities, Partner Country Series, 2013, p. 44.

Gas-on-gas pricing, also known as hub pricing, is the dominant price formation model for bilateral contracts in liquid wholesale gas markets. In this context, a buyer and seller would sign a bilateral contract to provide volume security, but not price security. The contract price would be set with reference to a hub price that both parties agree is a credible, liquid benchmark. To minimise daily volatility, parties may agree to settle on a month-ahead price with, say, a three month lag or any combination of alternative reference prices negotiated.[15]

A number of domestic GSAs on the east coast of Australia have recently been linked to oil.[16] In a market where some gas contracts are linked to the price at a gas hub and others to an oil price, arbitrage opportunities may arise. For instance, if prices in oil linked contracts are above the hub price, participants will try to minimise their contractual nominations and purchase gas off the hub.

Arbitraging hub and contract prices should drive the spot price at the hub towards bilateral contract prices and is a way of monetising the load factor flexibility in GSAs. GSAs have typically included load factors that allow shippers to vary their average daily quantities by a set proportion, such as 10-20 per cent. This supply flexibility is negotiated into contracts to allow shippers to meet their peak demand, such as the winter peak retail load on the east coast.

Flexibility in GSAs can be expensive for producers, as the production facility (and associated capital) is underutilised outside peak periods. Producers may seek to run their plants at high capacity factors in the future and become more reluctant to offer bilateral contracts to gas users with large amounts of supply flexibility. If this occurs, it will increase the importance of facilitated markets in:

1. allowing shippers to easily sell additional contracted gas outside of their peak periods; or

2. providing a mechanism for shippers to purchase gas on a short term basis to meet their peak demand.

In a liquid wholesale gas market, the price risk inherent in linking bilateral gas contracts to hub prices and/or purchasing spot gas to meet peak demand can be hedged using financial derivatives. This is similar in concept to how spot price volatility can be managed in the National Electricity Market (NEM). Financial trading of gas is discussed further in section 6.

A less observable feature of a liquid wholesale gas market is the trading culture of buyers and sellers. Historically in Australia, risk has been managed through the provision of long term, take or pay contracts with limited opportunity for price revision. This is a different mindset to a market where gas portfolio management is carried out on a more dynamic basis, where positions in the contract, spot and storage markets are actively traded in search of commercial opportunities. A change in trading

15 For example, prices could be based on the daily, weekly and month-ahead products at the Wallumbilla GSH.

16 EnergyQuest, *Energy Quarterly*, May 2015, p. 26.

culture can take time, particularly for market participants who need to establish this capability (eg, IT, staff, processes, governance).

To support the physical and financial trading of gas, a liquid wholesale gas market requires:

1. a relatively simple design that minimises transaction costs and encourages a diverse number of players and adequate volumes of gas to support trading liquidity;
2. an ability to ship gas into and out of the hub(s) area; and
3. accurate and timely information to make trading decisions.

Each of these is discussed below.

3.2.2 Number and type of players and volumes of gas

A liquid wholesale gas market requires different types of buyers and sellers transacting sufficient volumes of gas to support trading liquidity. A simple and low cost market design, relative to the commodity being traded, will lower barriers to entry and contribute to greater participation.

A variety of market participants supports the development of trading liquidity through negatively correlated demand profiles. For example, a large industrial user offline for maintenance may wish to monetise its contracted gas on a spot market, which could be purchased by a gas-fired generator who is willing to generate given conditions in the NEM.

While a greater number of negatively correlated demand profiles increase the opportunities for trade, there must also be adequate volumes of gas available to support liquidity, and the ability to move gas to where it is required. If traded volumes are limited, then even small trades relative to the size of the market are likely to move the price. If this occurs, participants will lose confidence in the price signal and withdraw from the market, decreasing liquidity further.

Throughout this paper, we draw on three international gas hubs that are widely considered to represent liquid wholesale gas markets – being the NBP, the TTF and the Henry Hub in the US. Table 3.2 compares a number of key statistics with the gas market on the east coast of Australia (where available) and the international hubs.

Table 3.2 Characteristics of wholesale gas markets

Market characteristics	NBP	Henry Hub	TTF	East Coast of Australia
Consumption (2013, PJ/year)	3,074(i)	28,410(i) (US, total)	1,550(ii)	686(iii) (1,960 estimated in 2018 once all LNG trains under construction are operational)
Length of transmission network (km)	7,600(i)	488,000(i) (US, total)	11,256(i)	20,000(iv)
Number of market participants	176 shippers (2015)(v)	180 customers (2003)(vii)	127 active traders (2014)(vi)	DWGM:52 registered participants(viii) STTM: 9 (Brisbane), 11 (Adelaide) and 16 (Sydney) unique shippers and/or users(viii) GSH: 5-9 participants trading (per month since market-start)(ix)

Sources: (i) Market Reform, International Gas Markets Study, Report to the Australian Energy Market Commission, May 2015; (ii) Eurostat, Natural Gas Consumption Statistics; (iii) AEMO, National Gas Forecasting Report 2014; (iv) AER, State of the Energy Market 2014, 19 December 2014, p, 110; (v) UK Working Group Report to the All Party Parliamentary Group on Energy Costs, Wholesale Gas Market, March 2015, p. 12; (vi) Gasunie Transport Services B.V., Annual Report 2014, p. 9; (vii) EIA, Natural Gas Market Centers and Hubs: A 2003 Update, October 2003, p. 6; (viii) AEMC, East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 1 Final Report, July 2015, Appendices F & G; (ix) AER Wholesale Statistics.

3.2.3 Ability to ship gas into and out of the hub area

In order to trade gas at a hub, sellers must have capacity rights to transport gas to the point of sale, and buyers must have capacity rights to transport gas away from the point of sale. The ability to ship gas into and out of a hub area is particularly important for liquidity to emerge at physical hubs, or narrowly defined virtual hubs, where gas is traded at specific physical locations on the pipeline system.[17]

Where a market includes more than one hub, efficient transportation arrangements that enable gas to flow freely between locations are required so that arbitrage between hubs can occur. Long-term differentials between hub prices in a liquid wholesale gas market should therefore reflect the efficient cost of transporting gas between these locations.[18]

17 The Brattle Group, *International Experience in Pipeline Capacity Trading*, A report for AEMO, August 2013, p. 4.

18 Assuming transportation constraints are built out in response to any persistent price differentials.

Approaches to facilitating efficient investment in, and use of, gas transportation infrastructure have varied across the east coast of Australia. The appropriateness of the current arrangements in the future, and the possibility of any changes to these arrangements, are being considered through this review as part of the Pipeline Capacity Trading workstream, as illustrated earlier in Figure 2.1.

3.2.4 Accurate and timely information to make trading decisions

An important feature of a liquid wholesale gas market is the accurate and timely provision of information. Information aids decision making, allowing participants' preferences to be acted upon and accurate trade-offs to be made. Market outcomes will be partially a function of the information on which the participants are able to act.

Developed wholesale gas markets in Europe and the US have substantial market transparency requirements and robust mechanisms for the provision of market information relating to prices. For example:[19]

- Exchanges publish current and historical pricing, trade volume, open interest and other information. Typically all except real-time feeds are made available to the public free of charge.

- Major price reporting services (such as ICIS Heren, Argus and Platts) provide, on a subscription basis, spot and forward gas prices and analysis covering major trading locations. In the US, certain market participants are obliged to report information to price-index publishers.[20]

- In Europe, the London Energy Brokers Association operates a service for the collection, validation and distribution of price and volume indices, and forward price curves. These indices are widely used in pricing shorter-term (up to a year out) contracts with retailers and transmission users.

Gas markets in Europe and the US also typically have arrangements for the provision of non-price information. Facility operators provide information on gas flows, operational constraints and utilised and available capacity.

In the US, each pipeline maintains its own bulletin board with information on any existing capacity available for purchase (amongst other things). This capacity may be purchased at a regulated rate, or the parties may agree a negotiated rate – although to ensure transparency, pipelines are required to provide details of all negotiated contracts.[21]

19 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, May 2015, p. 19.

20 FERC Order 704-A establishes requirements to report information to price-index publishers, as well as certain annual information to FERC.

21 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, May 2015, p. 14 & 19.

In Europe, cross-border capacity information is centralised to the PRISMA platform, and information on major flows is published on the Transparency Platform of the European Network of Transmission System Operators for Gas. National Grid also runs an operational data site that provides a snapshot of real time and contextual data on the current status of the transmission system in the UK.[22]

The appropriateness of the current information arrangements moving forward for the east coast gas market are being considered as part of the information and bulletin board workstream, as illustrated in Figure 2.1. The current arrangements for information provision were developed prior to the changing market conditions driven largely by LNG exports.

3.3 What a liquid wholesale gas market could look like in Australia

The following section describes a high level hypothetical scenario around what a liquid wholesale gas market could look like on the east coast of Australia beyond 2020. We have included this to help illustrate how some of the market characteristics described above and later in this paper could be applied in Australia and to contrast the hypothetical market with today's arrangements.

In a hypothetical future east coast gas market, there are two liquid trading hubs - one in Queensland and one in Victoria. These markets produce a 'northern' and 'southern' reference price for gas, each primarily influenced by local supply and demand conditions. For instance:

- The northern reference price is influenced heavily by LNG operations, as that industry is the largest user and potential supplier of gas on the east coast. Unplanned maintenance on production facilities supplying the LNG plant will likely require the LNG operators to purchase spot gas, resulting in a high price. Conversely, unplanned outages of the liquefaction plant could result in a significant oversupply of gas, pushing the price down.

- The southern reference price is primarily influenced by weather conditions in south and south east Australia, with the majority of the load being winter peaking residential and commercial customers. However, given the scale of Queensland's LNG load compared to the domestic market, the southern reference price is likely to be periodically influenced by supply and demand conditions in the north.

The degree to which traders can arbitrage the northern and southern reference prices primarily depends on:

- the degree of price separation - whether the total transaction costs of moving gas between the two hubs is profitable;

22 See: http://www2.nationalgrid.com/UK/Industry-information/Gas-transmission-operational-data/

- the availability and price of pipeline transportation capacity; and
- volume of gas - whether the volumes of gas to be traded make the transaction profitable and physically possible.

Bilateral contracts continue in this hypothetical scenario to be the preferred vehicle for purchasing wholesale gas and pipeline capacity, although growing volumes of both the commodity and pipeline capacity are being traded. Price formulae in bilateral contracts are progressively being linked to the northern or southern reference prices, depending on the locations of counterparties. To dampen price volatility, some contract pricing formulae reference a combination of these prices.

In this scenario, market-based balancing takes place within the northern and southern trading hubs, while participants also make use of low cost, market-based balancing arrangements at demand centres in Adelaide and Sydney. A pipeline connecting the Northern Territory to the east coast gas grid has recently been completed and, because of this, Moomba is expected to become a transit zone for large volumes of gas.

Gas users and producers in this scenario have been utilising spot markets more as a way of optimising their purchasing and sales activities, respectively. For instance:

- Gas users have been purchasing gas opportunistically in response to signals in downstream markets, such as a gas-fired generator running in response to prices in the NEM, a fertiliser manufacturer meeting a spike in their demand and an LNG producer selling spot cargos.
- Mid-tier producers involved in shale gas exploration in the Cooper Basin have been monetising flows from their wells at the northern and southern hubs.
- Large industrial manufacturers have been arbitraging differences between bilateral contract and spot prices, as described in Box 3.1.

As producers have been seeking to retain greater flexibility in how they run their plant, load factors or 'flex' traditionally offered in bilateral contracts is instead being sold into the northern and southern spot markets. Producers with additional processing capacity and gas sell this in response to price signals, while gas users who have surplus contracted gas do the same. This activity has grown over time and is contributing to liquidity in the market.

Concentration of liquidity at two pricing hubs, along with the ability to readily move gas into and out of the hubs through pipeline capacity trading, has supported confidence in the physical markets and price signals at the hubs. This has resulted in the ASX, in conjunction with industry participants, launching financial derivatives based on the most actively traded physical products to hedge against price risk.

Trading of financial products grows steadily, resulting in new players entering the market (both physical and financial) and growing levels of competition. Trading momentum in both the physical and financial markets begins to increase strongly, creating a virtuous cycle of liquidity and reinforcing confidence in the hub prices.

4 Locations for the title transfer of gas (hubs)

A gas hub represents a location where the *transfer* of ownership and pricing of physical gas takes place. Gas hubs can be used as reference points for the delivery of both *contracted* and *traded* gas.

For a hub to be successful in promoting deep and liquid trading of gas, it must have at least two basic characteristics:[23]

- the ability to move gas into and out of the hub area; and
- there must be a use for the gas, either through the existence of a significant customer base, or through the demand from other markets that can be reached from the traded hub.

Gas hubs can be defined as either a *physical* or *virtual* point, with this definition typically depending on the nature of the underlying transmission pipelines. These two types of hub are discussed in the sections below.

4.1 Physical hubs

Physical hubs allow for title transfer of gas at a specific location within a pipeline system. This type of hub design has the benefit of providing signals on the price of wholesale gas at specific locations. In addition, since physical hubs encompass a relatively small section of a transmission pipeline, they are relatively simple to keep in balance by the hub operator compared to a virtual hub defined by a larger geographical area.[24]

While it may seem logical to limit the title transfer of gas to a specific physical point, this approach will often require many such points in a pipeline system, particularly if capacity trading is illiquid and gas cannot be easily moved to and from a hub. If gas trade within a region is conducted at many physical points, then gas may cease to be a liquidly traded commodity as the number of products that companies need to trade is multiplied. The more the market is sub-divided, the more liquidity is diluted, impacting on the ability of participants to affect trades.[25]

Further, to trade gas at a physical hub, the seller can only sell to counterparties that have transport capacity from the hub. The need to acquire transport capacity to be able

---

23 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 46.

24 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 53.

25 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 53.

to buy the gas can limit the pool of potential buyers and sellers, making trading less liquid if pipeline capacity cannot be freely traded.[26]

4.2 Virtual hubs

In contrast to physical hubs, a virtual hub represents the transfer and pricing of gas at a notional point across an entire transmission system or a defined region within a pipeline system. Virtual hubs allow for title transfer of gas anywhere within the definition of the hub, thereby providing participants with greater flexibility than a physical hub.

Virtual hubs concentrate trading across large geographic areas, avoiding the situation where trade is split over a number of physical locations, which can negatively impact liquidity and the emergence of a liquid spot market.[27] When the UK market was liberalised there was a debate as to whether trading should occur on beach terminals or at a virtual point across the transmission system. In the end the advantages of having one single market outweighed those of physical locations and the NBP was created; the principal reason being to ensure liquidity.[28]

In designing a virtual hub, there is a balance to be made between defining the geographic region of the market so narrowly that the locational information reflects the price of wholesale gas at a specific point in the network, but liquidity is low; and defining a market so broadly that liquidity is high, but the price gives less useful supply, demand and locational signals as it reflects conditions across a wide region.[29]

Virtual gas hubs typically require a complementary system for allocating and pricing transmission capacity into and out of the virtual hub area (since these typically encompass large geographic regions). The most common form is an 'entry-exit model' where network users book capacity rights independently at entry and exit points. Under this approach, gas that enters a virtual hub can be withdrawn at any exit point.[30]

While the majority of participants will usually have long term entry and/or exit capacity booked to meet their requirements, short term capacity products are essential for short term gas trading. Using within-day, day-ahead and weekly capacity products, participants are able to optimise their gas trading activities. In the UK, short and long term entry-exit rights are auctioned periodically, with participants also free to trade

---

26 The Brattle Group, *International Experience In Pipeline Capacity Trading*, Prepared for AEMO, 5 August 2013pp. 4-5.

27 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 48.

28 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 53.

29 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 53.

30 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 5.

bilaterally in a secondary market.[31] In addition, rules were introduced in 2013 across the European Union to auction the entry/exit capacity between transmission systems (known as Interconnection Points), which is designed to facilitate gas trading between hubs.[32]

As outlined in section 7 below, in the UK and Europe pipeline system operators are generally responsible for keeping the network 'balanced'. For instance, while shippers in the NBP are incentivised to keep the system in balance, if required, National Grid can enter the market and act as the residual balancer by trading, within the constraints of the transmission regulatory framework. The level of difficulty inherent in balancing a virtual hub is related to its physical size and the network's characteristics, such as linepack.

The Commission notes that moving to a virtual hub(s) with an entry-exit regime on the east coast of Australia would likely require significant regulatory and commercial changes. From an entry-exit perspective, existing firm capacity rights would need to be appropriately transitioned into the new regime, while pipeline system operators would need to re-evaluate technical capacity at entry and exit points, as well as likely flows across the hub definition.

An alternative to developing an entry-exit model is having transmission capacity being traded implicitly, ie, capacity and commodity traded together, as is done in the DWGM. As this mechanism is currently operational in Victoria and is being considered through coincident DWGM review, the model is not covered in detail in this paper. However, we note that different capacity allocation mechanisms will have different incentives on investment and operational responsibility.

4.3 Gas trading hubs on the east coast of Australia

There are currently a number of hubs on the east coast of Australia that can broadly be categorised as physical hub, these are:

- interconnects between the Moomba to Adelaide Pipeline System and the SEA Gas Pipeline with the distribution network (ie, the Adelaide STTM hub);[33]
- interconnects between the Moomba to Sydney Pipeline and the Eastern Gas Pipeline with the distribution network (ie, the Sydney STTM hub);[34]
- interconnects between the South West Queensland Pipeline, the Queensland Gas Pipeline and the Roma to Brisbane Pipeline (ie, the Wallumbilla GSH);[35] and

---

31 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 47.

32 Official Journal of the European Union, *Commission Regulation (EU) No 984/2013 - establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009 of the European Parliament and of the Council*, 14 October 2013.

33 NGR rule 371.

34 NGR rule 372.

- interface between the Roma to Brisbane Pipeline and the distribution network (ie, the Brisbane STTM hub).[36]

The east coast also currently has one virtual hub being the DWGM, which encompasses the entire DTS. Figure 4.1 illustrates the gas trading hubs on the east coast.

35 As set out in the GSH Exchange Agreement.

36 NGR rule 373.

Figure 4.1 Gas trading hubs on the east coast of Australia[37]

Source: AEMC developed drawing on information contained in the 2015 AEMO Gas Statement of Opportunities Map for Eastern and South Eastern Australia.

37 We note that due to the predominant flow of gas and pipeline utilisation, it is not always possible to flow gas on an opportunistic basis to and from any hub location on the system.

5 Physical trading of gas

Parties trade physical gas in order to satisfy the requirements of their business. Physical gas requirements will typically be sourced from longer-term *contracted* gas supplies, but participants may wish to 'fine tune' actual volumes as the delivery date approaches through markets. In addition, parties that do not have GSAs in place may look to source gas through a facilitated trading market in order to meet their requirements.

5.1 Market-based physical gas trading

Market-based physical trading of gas is based on the negotiation of physical trading contracts between buyers and sellers. There are many types of physical trading contracts, but most share some standard specifications, including:[38]

- specifying the buyer and seller;
- the price;
- the amount of gas to be sold (usually expressed in a volume per day);
- the receipt and delivery point;
- the tenure of the contract (usually expressed in number of days beginning on a specified day); and
- other terms and conditions (such things as the payment dates, quality specifications for the gas to be sold and any other specifications agreed to by both parties).

Markets tend to define a slate of standardised 'products', whose characteristics are well understood. This standardisation encourages transactional efficiency and the development of liquidity.[39] The financial gas market (outlined in section 6 below) is directly linked to the physical gas market and usually evolves from some form of standardised contract for the sale of physical gas.

Conceptually, there are two distinct markets for physical gas in a market-based set of trading arrangements:

- a cash market, which is a daily market where gas is bought and sold with delivery today or tomorrow (spot) or within the month (prompt); and
- a forward market, where gas is bought and sold under contract for future delivery (eg, one month or more).

38 FERC, *Energy Primer*, A Handbook of Energy Market Basics, July 2012, p. 33.

39 Market Reform, *Evolution of the Gas Supply Hub*, October 2013, p. 15.

Spot and prompt contracts are traded to physically optimise or balance a contractual gas portfolio at, or just ahead of, delivery. It is estimated that about 70-80 per cent of traded gas in the UK is traded in spot and prompt markets.[40]

A market-based approach to trading gas is commonplace in Europe and the US, where parties can trade a variety of spot, prompt and forward products via OTC as well as on exchanges. An overview of OTC and exchanges and the current east coast arrangements are provided below.

5.1.1 OTC

OTC trades are a form of bilateral contract between two parties or, more commonly, via a broker who helps the two parties find each other and reach agreed terms. Prices struck between parties via OTC contracts are generally not published.

While OTC contracts represent agreements between two parties, they primarily differ from longer-term bilateral contracts in that they cater for shorter durations. OTC contracts are also typically based on standardised terms and conditions, while long-term contracts are highly customised.

The price discovery process associated with OTC contracts largely depends on the terms agreed by the two parties. For example, it may simply involve a $/GJ price (and associated price revision procedure) negotiated between the two parties, or a price linked to an external benchmark (eg, a published price index).

OTC trades constitute the most common form of trading in the UK. These are standardised physical deals based on the NBP'97 contract. Despite the standardisation of these contracts and their popularity, OTC deals are still bilateral contracts and therefore hold counterparty credit and some performance risk. Almost all of the trades are for gas delivery at the NBP virtual hub.[41]

In the US, all short term trading is conducted bilaterally between parties, facilitated through brokers or via bulletin boards.[42] Short term transactions are normally conducted via telephone or on exchanges (outlined in the section below), with the buyer agreeing to pay a negotiated price for the gas to be delivered by the seller at a specified delivery point.[43]

OTC trades are notified to the operator of the hub so that the system can be monitored and balanced (as outlined in section 7 below).

---

40 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, p. 28.

41 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, p. 25.

42 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, May 2015, p. 90.

43 FERC, *Energy Primer*, A Handbook of Energy Market Basics, July 2012, p. 34.

5.1.2 Exchange trading

Exchanges facilitate trading of highly standardised contracts across various durations using electronic platforms (eg, Trayport for the Wallumbilla GSH). Execution of trades is typically quick and cheap, relative to OTC contracts and especially bilateral long-term contracts.[44]

Exchanges post price and volume information of executed trades as well as the prices and volumes that parties are willing to exchange. These two sets of information provide key price and volume discovery for participants wishing to trade.

Trading on an exchange is anonymous, with a clearing house sometimes being the central counterparty that financially guarantees all of the trades executed (ie, assumes the 'counterparty risk'). Clearing houses are frequently part of the organisation that operates the exchange and are responsible for managing the counterparty risk so that trading can occur in isolation of it.[45]

Alternatively, exchanges may act as a 'matching service' whereby the exchange matches buyers and sellers but does not assume the counterparty risk. For example, the Wallumbilla GSH has been designed to centrally manage the counterparty risk as a service provided by the market operator, whereby the risk of a payment default is borne by all traders that are owed money by the market. AEMO, for example, requires that participants post collateral to cover the potential settlement exposure associated with their hub transactions to minimise the risk of payment default impacting on the payment of participants by the market.[46]

Similarly to OTC, transactions facilitated via an exchange are notified to the operator of the hub so that the system can be monitored and balanced (as outlined in section 8 below).[47]

Products offered by AEMO for gas trading at the recently established Wallumbilla GSH are currently the only exchange-based products traded on the east coast.[48] There are currently four trading products on offer, all of which are available separately for each of the three trading locations. These range from balance-of-day to weekly.

---

44 Market Reform, *Evolution of the Gas Supply Hub*, October 2013, p. 16.

45 OECD & IEA, *Developing a Natural Gas Trading Hub in Asia Obstacles and Opportunities*, 2013, p. 38.

46 AEMO, *Detailed Design for a Gas Supply Hub at Wallumbilla*, 19 October 2012, p. 22.

47 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 42.

48 We note that in 2009, the Australian Stock Exchange introduced a number of derivative products that are linked to the price payable at the beginning of the day in the DWGM. However, we understand that these products have not been heavily traded, which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers, and then selling it to themselves through the DWGM using bilateral contracts.

5.1.3 Physical trading on the east coast of Australia

In addition to OTC and exchanges, trading of physical gas can also occur on a centrally cleared market, where supply is matched to demand and a single price applies to all gas transacted through the market over a specific time period. This approach is adopted on the east coast through the design of the STTM and DWGM, and is common in wholesale electricity markets.

The STTM and DWGM were developed, in part, to encourage retail competition at the major demand centres of Brisbane, Sydney, Adelaide and across Victoria. All gas consumed at these locations is required to be traded on the STTM and DWGM, respectively.

Prices in both the STTM and DWGM are set via a merit order that occurs once a day and five times per day, respectively. These merit orders determine a marginal price based on participants' bids and offers and apply this price to all gas transacted through the market for that trading interval. This is in contrast to trading via an exchange, where prices struck apply to specific trades alone, as well as OTC contracts, where trading terms and conditions can be more bespoke in nature.

A key feature of the STTM and DWGM is that there is not a single price in these markets that is faced by all buyers and sellers that allows participants to hedge against all of the risks associated with the market.[49] In addition to the commodity price, some participants face risks around various uplift and deviations charges, which makes it difficult for financially traded products to emerge. Financially traded products typically require a standardised underlying physical product to reference (as outlined in section 6 below).

---

49 K Lowe Consulting, Gas Market Scoping Study, A report for the AEMC, July 2013, p. 96.

6 Financial trading of gas

Unlike physical trading, financial trading does not always result in physical volumes being delivered. This is because participants can financially close out their positions before the delivery date of the contract. The financial trading of gas is undertaken to:

- financially hedge business exposure to gas prices; and/or
- speculate on future price movements.

This section outlines how these activities take place in the wholesale market for gas.

6.1 Hedging

Gas users can mitigate their future exposure to varying gas prices through hedging. Financial hedging protects future profit margins by securing a price today for future delivery. Having established the level of future physical trading required, financial hedging can be used to lock in the expected cost or profit margin.[50]

The primary instruments used to hedge gas are forwards, swaps, futures, and options:[51]

- Forward contract: agreement between two parties to buy or sell physical gas at a future time, at a specific price, which is agreed upon at the time the deal is executed.
- Futures contract: a commitment to make or accept delivery of a specific quantity and quality of gas at a price agreed upon at the time the commitment is made. Only a small percentage of gas futures result in delivery as most parties will close out their position prior to expiration to avoid making or taking delivery. In the US, gas futures are traded on the NYMEX.
- Swap: an OTC contract in which two parties agree to exchange periodic payments for gas. In the most common type of gas swap, one party, such as a large gas consumer, agrees to pay a fixed price for gas on specific dates to a counter-party who, in turn, agrees to pay a floating price for gas that references a published price, such as the NYMEX gas futures. Gas swaps are generally financial transactions that do not involve the purchase or sale of physical gas.
- Options: are contracts that give the holder the right, but not the obligation, to buy or sell a specified amount of gas (or a gas swap or futures contract) at a specified

50 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, p. 21.

51 Mercatus Energy Advisors, A Primer on Hedging Natural Gas Costs, 1 March 2010, available at: http://www.mercatusenergy.com/blog/bid/34672/A-Primer-on-Hedging-Natural-Gas-Costs-Continued

price within a specified time in exchange for an upfront premium, similar to the premium on an insurance policy.

Some parties, such as hedge funds, banks, institutional investors and commodity traders may wish to speculatively trade in financial gas markets. Speculative trading of these parties provides liquidity to the market and supports close bid-offer spreads and the volumes that enable physical players to manage their portfolios.[52]

6.2 How hedging takes place

Physical and financial markets are often closely intertwined and can use the same trading platforms, which include:[53]

- OTC; and
- exchanges.

In the UK, the ICE gas futures contract is based on physical delivery of gas at the NBP and the exchange publishes a month ahead index which is commonly used to settle financial swaps. The ICE contract is used primarily as a hedging tool to manage price risk and for speculating, but also to effect physical transfers of gas, as a small percentage does still go to delivery.[54] In March 2015, ICE announced the NBP natural gas futures contract achieved a daily volume record of 146,780 contracts (equivalent to 472 PJ or 70 per cent of annual east coast gas demand).[55]

On 31 March 2015, the ASX and AEMO announced the launch of ASX Wallumbilla gas futures. It was noted at the time that “participants will be able to use the Wallumbilla GSH Benchmark price as a basis price for their gas contracts, with the development of a derivatives market providing a risk management tool for forward pricing and planning".[56] The AEMC understands that these futures products have not traded to date.

An example of how gas futures can be used to hedge price risk is provided in Box 6.1.

52 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, p. 24.

53 FERC, *Energy Primer*, A Handbook fo Energy Market Basics, July 2012, p. 109.

54 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, pp. 25-26.

55 ICE Press Releases, available at: http://ir.theice.com/press-and-publications/press-releases/all-categories/2015/03-19-2015.aspx

56 ASX Media Release, 31 March 2015, available at: http://www.asx.com.au/documents/asx-news/ASX-AEMO_Launch_Wallumbilla_Gas_Futures.

Box 6.1 Using gas futures to hedge price risk

A large industrial user estimates it will need to procure 1 PJ (1 million GJ) of gas in 3 months' time. The current spot price for gas is $6.00/GJ while the price of gas futures for delivery in 3 months' time is $5.50/GJ.

To hedge against a rise in the gas price, the user decides to lock in a future purchase price of $5.50/GJ by taking a long position in an appropriate number of gas futures contracts. Each futures contract is standardised to cover 1,000 GJ and so the user therefore will be required to purchase 1,000 futures contracts to implement the hedge.

The effect of putting in place the hedge should guarantee that the user will be able to purchase the 1PJ of gas at $5.50/GJ for a total amount of $5.50 million.

Scenario 1: Gas spot prices rise by 10% to $6.60/GJ on delivery date

The user will have to pay $6.60 million for the 1PJ of natural gas. However, the increased purchase price will be offset by the gains in the futures market.

By delivery date, the natural gas futures price will have converged with the natural gas spot price and will be equal to $6.60/GJ. As the long futures position was entered at a lower price of $ 5.50/GJ, it will have gained $1.10/GJ ($6.60/GJ - $5.50/GJ). With 1000 contracts covering a total of 1PJ of gas, the total gain from the long futures position is $1.10 million.

The higher purchase price is offset by the gain in the gas futures market, resulting in a net payment amount of $5,500,000 ($6.60 million - $1.10 million). This amount is equivalent to the amount payable when buying the 1PJ of gas at $5.50/GJ.

Scenario 2: Gas spot prices fall by 10% to $5.40/GJ on delivery date

With the spot price having fallen to $5.40/GJ, the large user will only need to pay $5.40 million for the gas. However, the loss in the futures market will offset any savings made.

By delivery date, the natural gas futures price will have converged with the natural gas spot price and will be equal to $5.40/GJ. As the long futures position was entered at $5.50/GJ, it will have lost $0.10/GJ ($5.50/GJ - $5.40/GJ). With 1000 contracts covering a total of 1PJ, the total loss from the long futures position is $0.1 million.

The savings realised from the reduced purchase price for the commodity will be offset by the loss in the gas futures market and the net amount payable will be $5,500,000 ($5.40 million + $0.1 million). Once again, this amount is equivalent to buying 1PJ of gas at $5.50/GJ.

7 Managing physical imbalances

Since physical gas supply and demand can vary more rapidly than the timeframe in which commercial action can be taken, all gas hubs experience imbalances.

This chapter outlines a number of considerations applicable to the balancing of physical gas, as well as the various methods for ensuring systems are kept in-balance, including those used currently on the east coast and abroad.

7.1 Balancing considerations

This section sets out a number of considerations relevant to balancing physical gas at a hub, including balancing periods, nominations and tolerances.

7.1.1 Balancing periods

The balancing period is the time over which injections and withdrawals are required to be balanced by shippers. Selection of the balancing period largely depends on system linepack, which is the range over which imbalances have no physical consequences for network stability. The degree of linepack flexibility depends on physical characteristics of the network, in particular the diameter and length of the pipelines, entry and exit pressures and gas density.[57]

There is a tradeoff inherent with selecting the balancing period. For instance, hourly balancing ensures customers who have high intraday load variability face the costs of system balancing, instead of socialising the costs over the market. However, drawbacks of hourly balancing include the cost of holding a substantial portfolio of hourly flexibility, which could create a barrier to entering the market.[58]

The majority of European Union Member States have a daily balancing system in place where imbalances are cashed-out at the end of the gas day.[59]

7.1.2 Nominations

In order for the hub to be kept in-balance, the party ultimately responsible for doing so needs to have an accurate account of the physical system in near-real, time. To do so, parties trading physical gas need to inform the system balancer, typically the pipeline operator, of their trades when they occur.

---

57 Van Dinther, A., and M. Mulder, *The Allocative Efficiency of the Dutch Gas-Balancing Market*, Competition and Regulation in Network Industries, 2013, vol. 14, issue 1, p. 51.

58 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 54.

59 The only Member State with a pure hourly balancing system is Finland. See: KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 78.

In the UK, nominations are used to notify National Grid Gas of expected gas flows through a system called 'Gemini'. There are three main nominations categories used by shippers on the NBP in the UK:[60]

- into the NBP on an entry service, specifying the entry point, date and quantity;
- from the NBP on an exit service specifying the daily metered site or exit point, date and quantity; and
- from NBP to NBP, for gas trading, specifying the date and quantity.

Outside of Victoria, nominations on the east coast are made by participants directly to each pipeline operator. The DWGM and STTMs facilitate market-based balancing at key demand centres, while outside of these areas balancing is generally carried out by the pipeline operator. Shippers, through contractual arrangements with the pipeline operator, are incentivised to follow their nomination schedules and remain in balance. If the pipeline system becomes unstable, pipeline operators can take action to ensure system security is not compromised, such as curtailing load.

7.1.3 Tolerances

Some pipeline operators in Europe generally allow shippers to be out of balance within some small technical tolerance, which usually is defined as a percentage deviation in total flows. These imbalance tolerances are charged for the hour (where hourly balancing applies), day and month. Most often there will also be limits not only on imbalances within the different time periods but also on the cumulative imbalances.

There are a number of arrangements in Europe that allow shippers to purchase these tolerances:[61]

- Most commonly, requirements for additional services can be met by purchasing unused tolerance services from other shippers.
- In some cases the pipeline operator offers to sell additional tolerance services to shippers, such as Energinet (the Danish pipeline operator) does at the Gas Transfer Facility.

We note that the use of tolerances in Europe is becoming less common and they are not part of what is seen as the target model for balancing. Tolerances are regarded as an interim step to market-based balancing, where the wholesale market is insufficiently liquid.[62]

---

60 Heather, P., *The Evolution and Functioning of the Traded Gas Market in Britain*, The Oxford Institute for Energy Studies, August 2010, pp. 9-10.

61 IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 54

62 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 47, p. L 91/33.

7.2 How balancing takes place

In a liquid wholesale gas market, the pipeline operator is typically responsible for maintaining a balanced hub.

At a conceptual level, a gas balancing regime in a liquid wholesale gas market can be considered to have the following two components:

- Primary system balancing: where each network user is incentivised to balance its own system injections and withdrawals; and
- Residual system balancing: in the event that network users are not collectively balancing their injections and withdrawals sufficiently, the pipeline operator can take actions to rectify the imbalance.

When shippers are incentivised to balance their injections and withdrawals, this minimises the pipeline operator's role in keeping the system in-balance.

Imbalance fees and penalties are often designed to cover the costs of balancing from shippers responsible for the system imbalance (ie, applying a 'causer pays' principle):[63]

- Imbalance fees (also referred to as a 'cash out') aim to partially or fully return the imbalances of the shippers to zero by a mandatory gas trade between the shipper and the system. Shippers are charged for the excess or the missing gas in the system based on a reference price (determined using the means outlined below).
- Penalties provide incentives for shippers to stay in balance and fees may include a penalising component applied either to the whole imbalance or only to the part above certain pre-defined tolerance levels.

The common approaches pipeline operators take to residual balancing are outlined below.

7.2.1 Market-based balancing

Where physical trading of gas is sufficiently liquid on a spot market, a pipeline operator can procure balancing gas from this mechanism. In this manner, market-based balancing enables cost reflectivity of residual pipeline operator actions by directly relating the cost of such actions to the actual commodity market price. Pipeline operators conduct residual balancing actions on the wholesale market and recover costs of doing so from participants.[64]

63 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, pp. 82 - 83.

64 Fluxys, *Transmission Programme Service Offer Description 2012-2015*, 26 March 2015, Section 6.1.

The European Commission's Network Code on Gas Balancing of Transmission Networks states that:[65]

> "The transmission system operators should aim to maximise the amount of their gas balancing needs through the purchase and sale of short term standardised products on the short term wholesale gas market."

A market-based balancing approach is expected to reflect the true market value of balancing gas and improve the overall liquidity of the general wholesale market, as well as cost reflectiveness of procuring balancing gas.[66]

The approach to balancing in the NBP is outlined in Box 7.1 below.

Box 7.1 NBP, UK: Cash-out balancing mechanism

National Grid balances the UK gas grid through the traded market operated by ICE-Endex. Shippers are actively incentivised to stay in-balance to minimise the actions taken by National Grid, for example:

- if a shipper at the end of the day has injected too much gas in an over-pressured system, they will be penalised by receiving a relatively low price for the extra gas (below the average of the within day deals on the market); and
- if a shipper has injected too little gas in an under-pressured system, they will have to pay a relatively high price (higher than the average of the trades) for the shortfall.

National Grid on the other hand rewards shippers that are 'helping' keep the system in balance. Shippers who at the end of the day, injected gas above their obligations in an under-pressured system are rewarded as are shippers who injected gas below their obligations in an over-pressured system.

To ensure that shippers can respond to this incentive, National Grid posts the pressure of the system to all shippers very frequently throughout the day, allowing shippers to undertake balancing actions, in the hope of being cashed out at a higher price than the within-day price. This arrangement means that:

- a shipper destabilising the system will lose money because of their imbalance, but that the loss will be proportional to the cost of rebalancing the system; and
- a shipper rectifying the system imbalance may earn money for their actions.

---

65 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 47, p. L 91/15.

66 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 81.

When during the day the system becomes too much over- or under-pressured, National Grid also has the option to rectify imbalances by buying or selling on the electronic OCM market which is also open outside ordinary office hours.

Source: IEA, *Development of Competitive Gas Trading in Continental Europe: How to achieve workable competition in European gas markets?*, IEA Information Paper, May 2008, p. 54.

7.2.2 Separate balancing platforms

Where physical trading of gas is insufficiently liquid in the short-term, a separate balancing mechanism (or 'platform') may be developed for procuring gas to balance the hub.

The European Commission's Network Code on Gas Balancing of Transmission Networks states that:[67]

> "Where the short term wholesale gas market has or is anticipated to have insufficient liquidity or where temporal products and locational products required by the transmission system operator cannot reasonably be procured on this market, a balancing platform shall be established for the purpose of transmission system operator balancing."

In this context, 'balancing platform' is defined as a trading platform where a transmission system operator shall be a trading participant to all trades.[68] A number of European member countries have a separate balancing platform and a virtual trading point.

In Europe it is foreseen that a separate balancing platform should only be applied temporarily and that ultimately the transition to procuring balancing gas through the general wholesale market should be made. This is reflected in the European Network Code, which only allows a separate balancing platform to be used for a period of up to 10 years.[69]

Box 7.2 outlines how a separate balancing platform used to be operated alongside the Dutch virtual trading point TTF and connected exchanges.

67 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 47, p. L 91/33.

68 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 3, p. L 91/17.

69 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 47, p. L 91/33.

Box 7.2 The Dutch TTF: Transitioning from a separate balancing platform to market-based balancing

Until recently in the Netherlands, a separate balancing platform was operated by the Dutch pipeline operator alongside the TTF. This platform took the form of a 'bid-price ladder', which represented a merit order of different volumes of gas market participants offered to the pipeline operator to respond to system imbalances.[70]

This approach to balancing was considered to have worked effectively and increased the amount of information available to participants.[71] In October 2014, the Dutch competition authority stated that it was keen to boost the TTF's liquidity by shifting balancing from the bid-price ladder to the TTF by 2014.[72]

In November 2014, the Dutch pipeline operator announced that it would begin balancing its system by trading on the TTF as part of a new agreement announced between the pipeline operator and the exchange (APX-ENDEX). This agreement allowed the pipeline operator to buy and sell balancing gas on the within-day and day-ahead markets.[73]

7.2.3 Contract-based balancing

In instances where the wholesale market has insufficient liquidity to enable the pipeline operator to procure balancing gas either via the wholesale market directly or through establishing a separate balancing platform, a number of contract-based balancing arrangements have been established.

In the European context, the European Commission's Network Code on Gas Balancing of Transmission Networks states that:[74]

> “Where the transmission system operator can demonstrate that as a result of insufficient interconnection capacity between balancing zones a balancing platform cannot increase the liquidity of the short term wholesale gas market and cannot enable the transmission system operator to

---

70 Van Dinther, A., and M. Mulder, *The Allocative Efficiency of the Dutch Gas-Balancing Market*, Competition and Regulation in Network Industries, 2013, vol. 14, issue 1, p. 57.

71 Heather, P., *Continental European Gas Hubs: Are they fit for purpose?*, The Oxford Institute for Energy Studies, June 2012, pp. 8-9.

72 ICIS, *Dutch regulator to decide on natural gas flexibility service by December*, 17 October 2012, available at: http://www.icis.com/resources/news/2012/10/17/9604877/dutch-regulator-to-decide-on-natural-gas-flexibility-service-by-december/

73 ICIS, *Dutch pipeline operator to balance natural gas grid via TTF by 2014*, 21 November 2014, available at: http://www.icis.com/resources/news/2012/11/21/9616623/dutch-pipeline operator-to-balance-natural-gas-grid-via-ttf-by-2014/

74 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 48, p. L 91/33.

undertake efficient balancing actions, it may use an alternative, such as balancing services, subject to the approval by the national regulatory authority. Where such an alternative is used, the terms and conditions of the subsequent contractual arrangements as well as the applicable prices and duration shall be specified."

'Balancing service' is defined as a service provided to a pipeline operator via a contract for gas required to meet short term fluctuations in gas demand or supply, which is not a short term standardised product.[75]

In the US, 'market centres' (also referred to as hubs) have developed at points where two or more transmission pipelines intersect. These market centres offer transportation services for shippers between pipeline interconnections, as well as with many of the physical and administrative support services, such as balancing, formerly handled via contract with the natural gas pipeline company.[76] An overview of the Henry Hub market centre is in Box 7.3.

Box 7.3 Henry Hub market centre[77]

The Henry Hub in Louisiana is considered to have developed into a deep and liquid trading location in part because of the hub operator's ability to offer shippers flexibility to change supply sources and end markets through interconnecting pipelines. The operator of the Henry Hub was the first in the US to use operational balancing agreements and has contracts with all interconnecting pipelines at the hub.

More broadly, market centres in the US offer a range of services relating to transportation between pipelines and physical short-term balancing, for example:

- no-notice service - where a shipper may exceed its daily nomination without incurring scheduling penalties (but it must not exceed the maximum daily quantity);
- park and loan - short-term 'lending' of gas when a shipper needs more than its nominated volume and short-term 'parking' of gas when a shipper needs less than its nominated volume; and
- wheeling - where shippers have the ability to change a delivery point by arranging delivery to an alternative location.

---

75 Official Journal of the European Union, *Commission Regulation (EU) No 312/2014 - establishing a Network Code on Gas Balancing of Transmission Networks*, 27 March 2014, Article 3, p. L 91/16.

76 In 1992, the Federal Energy Regulatory Commission (FERC) issued its Order 636, which required interstate natural gas pipeline companies to transform themselves from buyers and sellers of natural gas (bundlers) to strictly common-carrier transporters offering unbundled services. See: EIA, *Natural Gas Market Centers: A 2008 Update*, April 2009, p. 1.

77 The World Bank, Development of Natural Gas and Pipeline Capacity Markets in the United States, Policy Research Working Paper, March 1998, pp. 19, 45-46.

A key feature of gas balancing at market centres in the US is 'operational balancing agreements'. These are contracts that shippers have with market centres and pipelines to resolve imbalances among multiple shippers simultaneously so that shippers do not incur imbalance penalties levied by pipelines.[78]

Operational balancing agreements stipulate all terms and conditions that a shipper agrees to with a pipeline in terms of balancing gas. These contracts usually define tolerances, as well as cash-out charges for imbalance gas. Cash out charges could be a percentage of a predetermined index spot price published by Platt's or an agreed table of percentages depending on the magnitude of the imbalance.[79]

Prices of many services provided by market centres are unregulated and pipelines provide a competitive constraint.[80] However, FERC or State utility commissions regulate the prices of some services, such as transportation or storage-related services. FERC also requires that each pipeline company files balancing rules consistent with its own unique operation to facilitate a market in pipeline capacity.

7.2.4 Balancing on the east coast of Australia

Prior to the implementation of the facilitated markets, balancing was generally undertaken through contractual arrangements with pipeline operators or organised 'Swing Service' markets, such as what used to occur in Adelaide and under the current arrangements in south-west Western Australia.[81] Since the implementation of the DWGM and STTM, balancing at the major demand centres on the east coast now occurs through these markets.

Market Operated Service (MOS) is the primary on-the-day balancing mechanism for the STTM and operates separate to the ex ante wholesale market. MOS balances the difference between scheduled pipeline flows and what is actually delivered or consumed at the hub.

---

78 There are broadly three types of penalty: scheduling variance penalties - incurred when the daily flow of natural gas does not match the nominated flow; overrun penalties - incurred when the shipper's maximum daily quantity is exceeded; and imbalance penalties - incurred when the total receipts into the pipeline do not match the total deliveries to the shipper.

79 For example, see: Southern California Gas Company, *Operational Balancing Agreement (Form 6435, 11/2006)*, Sample Forms - Contracts, available at: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/OBA.pdf; and Gulfstream Natural Gas System, For of Service Agreement for Operational Balancing Agreement, available at: http://www.1line.gulfstreamgas.com/GulfStream/Files/GNGS_Form_of_OBA.pdf.

80 FERC Order 637 states that "pipelines will be required to provide imbalance management services, like parking and loaning service, and greater information about the imbalance status of shippers and the system, to make it easier for shippers to remain in balance in the first instance. Pipelines also will be required to permit third-parties to offer imbalance management services that will allow shippers to avoid imbalances. The use of these techniques will obviate the need for pipelines to rely on penalties to prevent or solve operational problems caused by shippers. This will allow penalties to be more narrowly crafted to focus on conduct that is truly detrimental to the system".

81 AEMO and REMCo, *Business case for a Short Term Trading Market in Western Australia*, available at: http://www.remco.net.au/attachments/article/60/WA%20STTM%20Assessment%20-%20Final%20(26-06-13)%20v6.pdf

MOS is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. The cost of providing MOS is recovered by AEMO from participants through deviation payments and charges.

Unlike in the STTM where balancing is carried out through shippers' park and loan pipeline services, in the DWGM shippers manage imbalances by trading on the market throughout the gas day.[82] Deviation payments are used to settle differences between market participants' scheduled and actual behaviour and to provide an incentive to not deviate from the nomination schedules.

82 The five standard schedules for the current DWGM gas day are at 6.00am, 10.00am, 2.00pm, 6.00pm, and 10.00pm.

8 Conceptual wholesale gas market designs

To continue to progress the debate on gas market development, and to provide stakeholders with the opportunity to provide more focussed feedback leading into the Commission's Stage 2 Draft Report, three high level market design concepts have been developed.

The three concepts do not represent a preferred option and have solely been put together as a way of seeking feedback from stakeholders. While they have been prepared with the Energy Council's Vision in mind, they have not yet been tested against the assessment framework set out in the Stage 1 Final Report and outlined in Appendix A.

The three concepts represent a range from incremental development to more pronounced changes to the current gas market arrangements on the east coast. The concepts therefore reflect changes of varying magnitudes to the status quo.

The Commission welcomes feedback on these concepts. We also note that there are other potential options that could be considered and encourage stakeholders to use the consultation process for this paper to suggest alternatives that could contribute to meeting the Vision established by the Energy Council.

8.1 Concept 1: Multiple physical hub locations

Concept 1 involves GSHs at Wallumbilla, Moomba, Longford, Iona and Gladstone, all of which would represent physical hubs. Separate balancing arrangements could be implemented at major demand centres in Adelaide, Brisbane, Melbourne, Sydney and potentially Canberra.

Figure 8.1 Concept 1: Multiple physical hub locations

Source: AEMC developed drawing on information contained in the 2015 AEMO Gas Statement of Opportunities Map for Eastern and South Eastern Australia.

8.1.1 How and where physical trading can take place

Under Concept 1, market participants would trade physical gas on GSHs at Wallumbilla, Moomba, Longford, Gladstone and Iona.

Each of the proposed GSH locations is at a location that connects sources of production with demand. For example:

- Wallumbilla, the site of the existing GSH on the east coast, is located in close proximity to significant gas supply and demand and is a major transit point between Queensland and the rest of the east coast. Wallumbilla marks the intersection of the RBP, the SWQP and the QGP;
- Moomba, can receive gas from either the Moomba Gas Plant or gas supply from other locations, such as the MSP, MAPS and SWQP and flow to three major pipelines (MSP, MAPS and SWQP).
- Longford, marks the intersection between the LMP, the EGP and the TGP and can receive gas from the Gippsland Basin.
- Gladstone, represents a point close to the LNG production facilities. A hub in Gladstone would allow LNG exporting parties and other industrial users in the area to trade gas close to their facilities and avoid having to go further afield (ie, Wallumbilla). There is also some production in the wider Gladstone area.
- Iona, represents a location that is close to both storage and production in the Otway Basin, as well as gas-fired power stations in Victoria and South Australia.

Concept 1 envisages that parties would have the ability to trade standardised products at each of these locations, such as currently occurs at the Wallumbilla GSH exchange. This concept is similar to the US, which has more than 30 physical hubs ('market centres') that are typically located at the intersection of major pipelines. While there are numerous hubs where trading can occur in the US, the Henry Hub has emerged as the principal reference price, and movements in price at this hub provide a good indicator of how prices are generally changing at other hubs across the country.[83]

The US gas industry is highly competitive compared to the east coast with thousands of producers, users and marketers trading gas.[84] The US pipeline transmission system operates on a contract carriage model and is characterised by multiple pipelines serving each hub, meaning that shippers generally have a number of choices for transporting gas between two physical hubs.[85] A question therefore exists as to whether there are likely to be sufficient potential market participants and volumes of gas to generate deep and liquid trading at multiple different locations on the east coast,

83 FERC, Energy Primer, A Handbook of Energy Market Basics, July 2012, p. 33.

84 FERC, Energy Primer, A Handbook of Energy Market Basics, July 2012, p. 32.

85 FERC, Energy Primer, A Handbook of Energy Market Basics, July 2012, p. 23

and for a meaningful reference price to emerge at one of the hubs. As noted by Brattle in a report to AEMO in 2013:[86]

> "…the conditions for a liquid physical hub are rather specialised, relative to the conditions for a liquid 'virtual' hub at an entry-exit system. The physical trading point or hub must connect a sufficiently large group of potential traders. This either requires the hub to connect a group of diverse pipelines and LNG terminals, so that at both physical locations there is a large group of market participants that can trade at that point. Alternatively, or in addition, market participants should be able to easily trade gas transport capacity to accommodate their commodity transactions. Otherwise, the pool of potential market participants will be limited, and it will be difficult for liquid gas commodity trading to develop."

Since gas would be priced (and the title transferred) at multiple physical locations, parties wishing to consume gas outside of these locations would need to be able to transport the gas to where they wish to use it. While not addressed directly in this paper, Concept 1 (and Concept 2) necessitates a set of underlying transmission arrangements so that participants can efficiently trade short and medium-term capacity to move gas into and out of the hub areas.

The Commission also notes that, depending on the hub definition, gas may not be able to flow freely between the interconnecting pipelines due to either physical or contractual congestion, as is currently the case at the Wallumbilla GSH. Because of this, hub services are likely to be required at some or all of these locations.[87]

8.1.2 How and where balancing takes places

Outside of the physical trading hubs, balancing would take place at the major demand centres in Adelaide, Brisbane, Canberra, Melbourne and Sydney using a common market platform. A common set of market arrangements for balancing gas on the east coast would reduce transaction costs and barriers to operating across multiple jurisdictions.

Balancing at the demand centres could be carried out on a daily or intra-daily basis. The balancing arrangements would be low cost, largely automated markets with the objective of efficiently and transparently managing shippers' imbalances. As the GSH locations would be where the bulk of the trading and price discovery occurs, prices at the demand centres are likely to be closely correlated to the nearest or most liquid supply hub.

Balancing at the physical trading hubs discussed above could initially be undertaken through GTAs with pipeline operators, as currently occurs in the system outside of the

86 The Brattle Group, *International Experience In Pipeline Capacity Trading*, Prepared for AEMO, 5 August 2013, pp. 5-6.

87 Hub services act to connect multiple points at a physical hub and facilitate trade in a single market.

STTM and DWGM. Over time as the markets grow and mature, balancing may become a hub service provided by the hub operator, as is the case in market centres in the US.

8.1.3 How and where financial trading can take place

Once trading has become sufficiently deep and liquid at one (or more) of the hubs, financial derivative products are likely to emerge to assist participants in managing price risk. Importantly, this will only occur if:

1. the underlying physical market design produces a reference price that encompasses all of the price risk faced by traders (including any uplift or other charges);
2. market liquidity has reached a point where counterparties are confident that the hub price represents the underlying value of gas and cannot be easily moved by the actions of a small number of players; and
3. there is demand from market participants for the introduction of financial derivative products.

In the US, NYMEX selected the Henry Hub as the delivery location for its natural gas futures based on the characteristics of that market centre. If this type of market framework was pursued for the east coast of Australia, we would expect market participants, in conjunction with an exchange such as the ASX, to drive the development and location of financial derivatives for natural gas.

8.2 Concept 2: Northern and southern virtual hub, with balancing at Adelaide and Sydney

Concept 2 involves the establishment of two virtual hubs on the east coast, namely:

- a new virtual hub in the northern region that encompasses the RBP and current Wallumbilla hub (the 'northern hub');[88]and
- a virtual hub in the south covering the Victorian DTS (the 'southern hub').

Concept 2, as shown in Figure 8.2, also includes balancing arrangements for Adelaide and Sydney.

[88] We note that the Single Trading Zone currently being considered by AEMO for the Wallumbilla GSH represents a small virtual hub.

Figure 8.2 Concept 2: Northern and southern virtual hub, with balancing at Sydney and Adelaide

Source: AEMC developed drawing on information contained in the 2015 AEMO Gas Statement of Opportunities Map for Eastern and South Eastern Australia.

8.2.1 How and where physical trading can take place

Concept 2 allows market participants to trade natural gas at the northern hub and the southern hub. The intention of Concept 2 is to concentrate trading liquidity at two hubs in order to foster the development of a northern and southern reference price for gas.

These two virtual hub definitions capture a large plurality of buyers and sellers of gas, namely:

- Northern hub: is at the intersection of major LNG terminals, CSG gas fields in Queensland, demand centres in Gladstone and Brisbane, gas storage facilities and gas-fired generation.
- Southern hub: all production, storage and demand across the entire Victorian DTS.

Being virtual hubs, title transfer of gas can occur at any location within the northern and southern hubs. This means that gas can be brought into the system at any entry point and withdrawn at any exit point, within the physical constraints of the system. Eliminating contractual transportation flows within the hub reduces the need to trade pipeline capacity when trading gas. Virtual hubs also avoid splitting gas trade over various specific physical locations and negatively impacting market liquidity.

To illustrate how this market could work, a large industrial customer on the RBP could purchase gas from a gas-fired generator at the northern virtual hub. To affect this trade, all that would need to occur is for the large industrial customer to have a capacity right to withdraw gas from the system and the gas-fired generator to have an entry right to inject gas into the system. The trade will occur regardless of where each market participant is located within the hub area.

Price discovery at the virtual hubs could occur via an exchange-based approach, where buy and sell orders are matched, similar to the Wallumbilla GSH. Consideration would also need to be given as to whether trading and balancing was conducted on the same market platform and the nature of participation (voluntary/mandatory). Further detail on the price discovery mechanism, and trade-offs between various approaches, have not been considered in this paper.

The northern and southern hub definitions have primarily been driven by the desire to capture as many potential buyers and sellers as possible within a relatively confined physical area. However, we note that the hub definitions also align with pipelines that are covered under the existing regulatory framework – the RBP (not including the Wallumbilla hub area) and the Victorian DTS. The pipeline infrastructure is also owned by a single entity within each virtual hub.[89]

Virtual hubs are typically implemented in conjunction with economic regulation of the underlying transmission pipelines and generally require a complementary system for allocating transmission capacity within the virtual point, as described in section 4.2.

89 Assuming the western point of the northern hub is defined by the APA compound at Wallumbilla.

Detail on how such a system could be implemented is not included in this paper, as the focus at this stage of the review is to seek feedback on high level design concepts.

Similar to Concept 1, parties wishing to consume gas outside of the two virtual hub locations, or sell gas from a production source outside of the hubs, would need transportation capacity to move gas into and out of the hub areas. However, as the hubs cover a larger geographic area than those in Concept 1, the requirement for capacity trading, particularly on the RBP, is likely to be reduced.

Over the long-run, observed price differences between the two virtual hub locations should reflect transportation costs, while any long term divergence would provide signals for new pipeline investment. Concept 2 therefore also requires a pipeline transportation regime that allows capacity to be easily traded in order to support the trading of gas between the two virtual hub locations.

Concept 2 could also include a GSH at Moomba in order to provide a centralised exchange for participants to trade gas at a strategic junction in the system. Over time, Moomba is likely to establish itself as a transit point for gas flowing between the northern, eastern and southern markets, particularly if the proposed pipeline from the Northern Territory into the east coast market is completed.[90]

While Moomba is located at a production and storage facility, there is little gas demand in the area, which is likely to dampen growth in trading liquidity. A GSH at Moomba would reduce transaction costs for participants who wish to trade incremental gas as it transits between the two virtual hubs or to major demand centres. As the average level of trading is likely to be low, prices at a Moomba hub could be expected to be correlated with the northern or southern virtual hubs.

8.2.2 How and where balancing takes places

Balancing at the two virtual hubs would be market based and part of the operation of the hub. Participants would be incentivised to remain in balance throughout the day and, if the system was in danger of becoming unstable, the pipeline operator would act as the residual balancer by participating in the trading/balancing market (within the constraints set by the regulatory framework).

Balancing at the Adelaide and Sydney demand centres would be the same as Concept 1, with prices likely to be correlated to either the northern or southern virtual hub reference price. In this concept, the focus is on the minimum number of hubs required for gas to be efficiently traded. The Canberra balancing mechanism has been removed in this concept as the focus is on the minimum number of hubs required to a achieve a liquid wholesale gas market.

90 See: http://dcm.nt.gov.au/territory_economy/north_east_gas_interconnector

8.2.3 How and where financial trading can take place

Similarly to Concept 1, once trading has become sufficiently deep and liquid at one of the virtual hubs, financial derivative products are likely to emerge to assist participants in managing price risk.

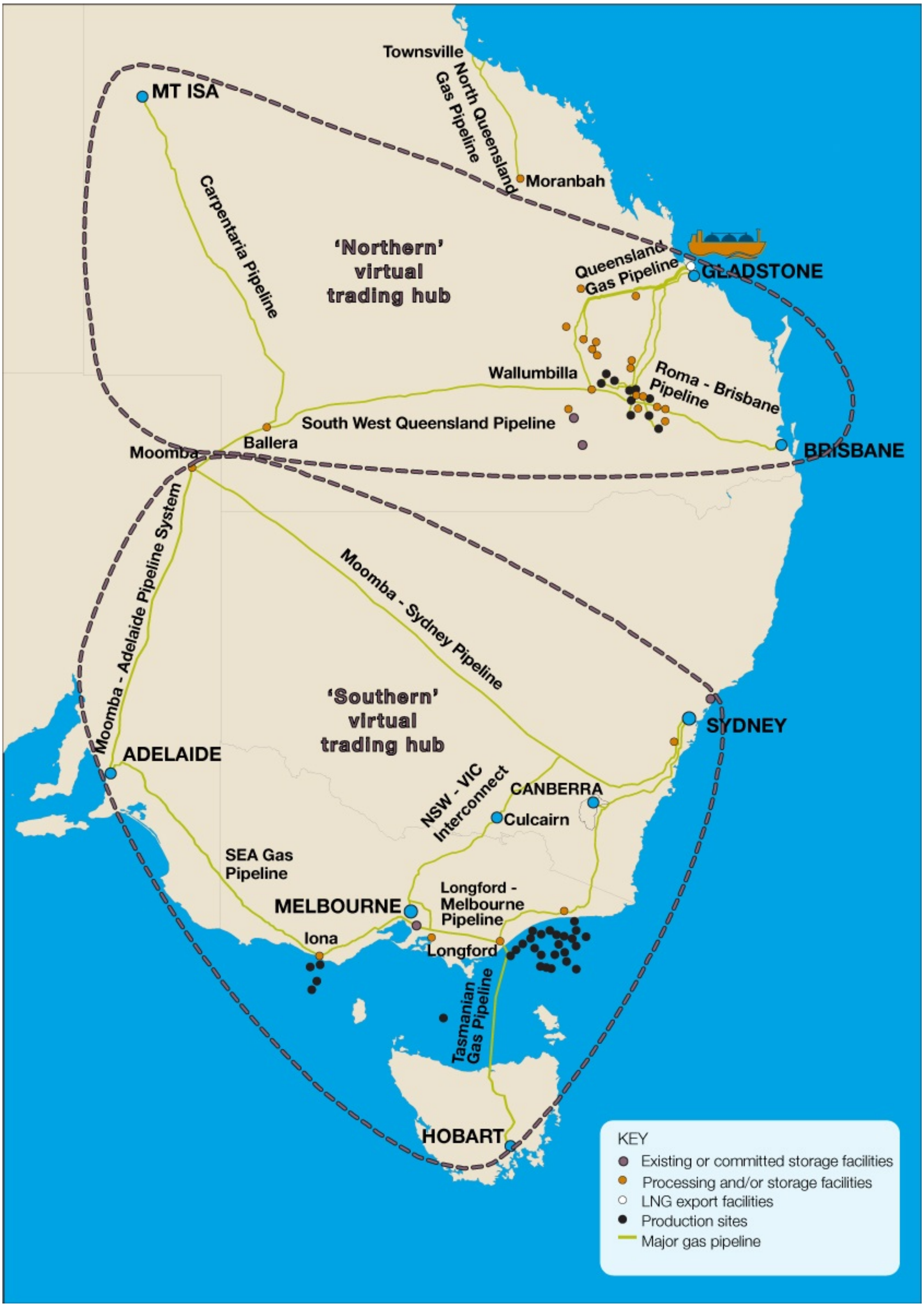
We anticipate that physical trading liquidity in this design will develop more rapidly than in Concept 1 due to the greater concentration of liquidity inherent in a virtual hub design. Because of this, there is more likelihood of financial derivative products being successfully established and traded, if sought be market participants, than in the first concept.

8.3 Concept 3: Two large virtual hubs covering the east coast

Concept 3 is an extension of Concept 2 and involves the establishment of a northern and southern virtual hub that, together, cover the entire east coast. Concept 3 has been designed to further concentrate the liquidity in trading in each of the northern and southern hubs by dividing the entire east coast into two definitions, as shown in Figure 8.3.

Under this high level concept there would not be a requirement for separate balancing arrangements at demand hubs as in Concept 1 and 2, as balancing would be catered for within each virtual hub.

Figure 8.3 Concept 3: Two large virtual hubs covering the east coast



Source: AEMC developed drawing on information contained in the 2015 AEMO Gas Statement of Opportunities Map for Eastern and South Eastern Australia.

8.3.1 How and where physical trading can take place

As with Concept 2, market participants can trade natural gas at the northern and southern hubs. However, the geographic definition of the hubs is far larger than Concept 2, as the intention is to maximise the trading liquidity in each of these hubs so as to foster the development of credible reference price for gas. Price discovery could occur through an exchange based approach, with balancing undertaken on the same or different platforms to trading, as noted above.

In this high level concept, a participant could theoretically purchase rights to inject gas at Moomba and withdraw gas from Hobart. Similarly, a participant could inject gas at Longford, withdraw gas at an exit point at Moomba, then inject gas at the entry point to the northern virtual hub at Moomba before withdrawing it at Gladstone. In both of these examples, the shipper would only be required to purchase entry and exit rights at the relevant locations, instead of having to establish a contractual relationship with multiple pipeline operators.

We recognise that Concept 3 represents a significant departure from the status quo and note the practicalities of implementing this high level design are likely to be complex and potentially costly. For instance, detailed consideration will need to be given to investment incentives and how investment would occur, the effect on pipeline to pipeline competition, and the entity responsible for managing the two virtual hub systems.

The reason for two virtual hubs instead of one covering the entire east coast is that the limited physical interconnection from north to south (via the SWQP) could result in significant balancing and/or infrastructure costs. While one virtual hub design would reduce administrative costs around system operation, capacity allocation and balancing, it may also involve greater costs associated with alleviating potential constraints within the hub area.

European Union member states typically consist of one virtual hub covering the national transmission network, however the limited network interconnectivity between northern and southern France has resulted in two virtual hubs.[91] However, in July 2011, the French trading exchange (Powernext), in conjunction with the pipeline operator, began offering a virtual spread between the two zonal prices. Since this came into effect, the price differential between the two zones has reduced from >€1/MWh (>$0.42/GJ) to virtually zero on most days.[92] The creation of a single marketplace in France is scheduled for 2018, following investment necessary for eliminating congestion in the gas transmission systems.[93]

91 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, p. 77.

92 Heather, P., *Continental European Gas Hubs: Are they fit for purpose?*, The Oxford Institute for Energy Studies, June 2012, p. 19.

93 La Commission de régulation de l'énergie, *Public consultation on the creation of a single gas marketplace in France in 2018*, 18 February 2014, p. 1.

8.3.2 How and where balancing takes places

Similar to the virtual hubs in Concept 2, balancing at the two virtual hubs would be market based and part of the operation of the hub. Participants would be incentivised to remain in balance throughout the day and, if the system was in danger of becoming unstable, the pipeline operator would act as the balancer of last resort by participating in the market (within the constraints set by the regulatory framework).

Due the physical size of the transmission pipelines within the virtual hub areas, balancing could be quite costly and complicated under this framework. It would also be necessary for the four different pipeline operators to establish relationships in order to ensure the system within the virtual hub definition is operated safely and efficiently.

8.3.3 How and where financial trading can take place

Similarly to Concept 2, once trading has become sufficiently deep and liquid at one of the virtual hubs, financial derivative products are likely to emerge to assist participants in managing price risk. We anticipate that liquidity in this design could develop more rapidly than in Concept 2 due to the significant concentration of physical trading and the effective elimination of the requirement to procure pipeline capacity to flow gas into and out of the hub areas.

9 Glossary

In undertaking research and analysis for this paper, it became clear that there is a degree of ambiguity around terms used to describe aspects of the gas industry. A list of common terms is defined below to establish a common basis when reading this document.

Balancing: the act of keeping the physical gas pipeline system within a predetermined set of safe operating conditions.

Clearing house: the body responsible for the clearing of exchange trades. As well as processing all of the trades, it financially guarantees their obligation.

Entry-exit system: a system for third party access to gas transmission networks. In an entry-exit system network users book capacity at entry points and exit points independently. Gas can be injected at the entry points and made available for off take at exit points on a fully independent basis. The gas does not follow a predefined contractual path. The entry-exit system has a virtual trading point where gas can change ownership within the system.

Exchange: a place or forum where securities or commodities are bought and sold in an open but regulated environment.

Exchange trade: a trade facilitated by an exchange.

Forwards: agreement between two parties to buy or sell physical gas at a certain future time, at a specific price, which is agreed upon at the time the trade is executed.

Futures: similar to forwards except immediate gains or losses are 'marked to market' daily and contracts are traded on organised exchanges.

Gas hub: a location where the transfer of ownership and pricing of physical gas takes place.

Gas users: all consumers of natural gas (eg, retailers, commercial, light industrial, heavy industrial customers, gas-fired generators, LNG producers).

Hub services: services provided within the confines of a gas hub, eg, services relating to transportation between pipelines and physical short-term balancing.

Market centre: term used in the United States to denote an arrangement that provides customers with access to two or more pipeline systems, provides transportation between these points, and offers administrative services that facilitate that movement and/or transfer of gas ownership.

Options: contracts that give the holder the right, but not the obligation, to buy or sell a specified amount of gas at a specified price within a specified time in exchange for an upfront premium, similar to the premium on an insurance policy.

Over-the-counter trade: bilateral trades, dealt direct or through brokers, as opposed to via an exchange.

Physical hub: represents the transfer and pricing of physical gas at a specific physical location on a pipeline system.

Producer: parties that are engaged in the production of natural gas from both off-shore and on-shore gas fields.

Shipper: a party responsible for delivering gas to a hub via a transmission pipeline.

Title transfer: the process of transferring ownership of physical gas.

Virtual hub: represents the transfer and pricing of gas within a general area, which typically encompasses a large segment, or all, of a pipeline system.

A Assessment Framework

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

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

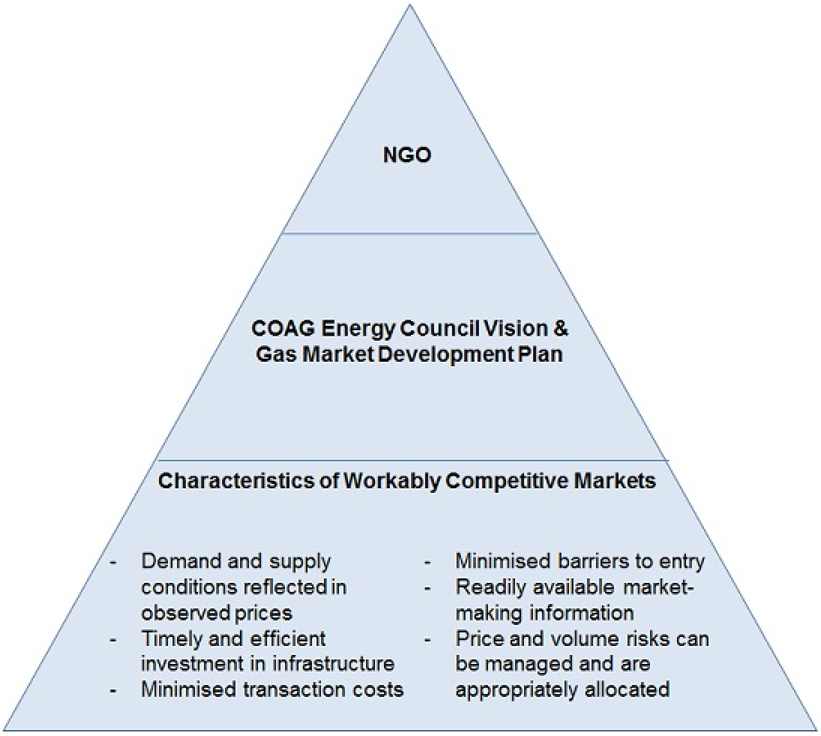
A.1 Assessment framework structure

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 A.1, and each is discussed below.

Figure A.1 Assessment framework



A.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:[94]

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.

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

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;
- 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.

A.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:[95]

> "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

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

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:[96]

1. **Encouraging competitive supply:**

    (a) Improvements to the regulatory and investment environment so that gas supply is able to respond flexibly to changes in market conditions.

    (b) A "social licence" for onshore natural gas development achieved through inclusion, consultation, improving the availability and accessibility of factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.

2. **Enhancing transparency and price discovery**:

    (a) Increased flexibility and opportunity for trade in pipeline capacity.

    (b) Competitive retail markets that will provide customers with greater choice and large users with enhanced options for self-supply and shipment.

    (c) Provision of accurate and transparent market making information on pipeline and large storage facilities operations and capacity, upstream 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.

---

96 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/

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.

A.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.[97] These are:[98]

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

---

97 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."

98 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.

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.