December 2015

Conceptual design for a virtual gas hub(s) for the east coast of Australia

CRITICAL THINKING AT THE CRITICAL TIME™

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Table of contents

Glossary

ACT	Australian Capital Territory
ACER	Agency for the Cooperation of Energy Regulators
ACQ	Annual Contract Quantity
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity
APA	Owner and operator of gas transmission pipelines and has an ownership interest in, and operates some distribution networks
APLNG	Australia Pacific LNG
Bcm	Billion cubic metres
Cm	Cubic metres
COAG	Council of Australian Governments
CSG	Coal seam gas
DWGM	Declared Wholesale Gas Market
DTS	Declared Transmission System
Eastern Australia	Australian Capital Territory, NSW, Queensland, South Australia, Tasmania and Victoria
EIA	Energy Information Administration
ENTSOG	European Network of Transmission System Operators for Gas
FERC	The Federal Energy Regulatory Commission in the US
FTI Consulting	FTI Consulting LLP
GLNG	Gladstone LNG

GSH	Gas Supply Hub
GWh	Gigawatt hour
GTS	Gasunie Transport Sevices, owner and operator of the gas transmission system in the Netherlands
IHT	Intra-Hub Transfers
IPART	Independent Pricing and Regulatory Tribunal
IPs	Interconnection Points
kWh	Kilowatt hour
LNG	Liquefied Natural Gas
LTCs	Long-term gas supply contracts
MAPS	Moomba-Adelaide Pipeline System
MOS	Market Operated Service
MSP	Moomba-Sydney Pipeline
MSV	Market Schedule Variation
NBP	National Balancing Point- gas hub in Great Britain
NCG	Net Connect Germany- gas hub in Germany
NSW	New South Wales
PEG	Point d'Echange de Gaz- gas hub in France
PJ	Petajoules
PSV	Punto di Scambio Virtuale- gas hub in Italy
RBP	Roma-Brisbane Pipeline
SA	South Australia
STTMs	Short Term Trading Markets
SWQP	South-West Queensland Pipeline
TJ	Terajoules
TSO	Transmission System Operator, owner and often also operator of transmission networks in Europe
TTF	Title Transfer Facility

VTP	Virtual Trading Point
WGP	Wallumbilla Gladstone Pipeline
WUGS	Western Underground Gas Storage

Executive summary

1.1 The purpose of this report is to provide the Australian Energy Market Commission (AEMC) with advice on the options and recommendations for developing a conceptual design for a liquid wholesale gas market in the East Coast of Australia. In particular, this report explains the options and makes recommendations for:

- The geographical location and scope of the trading point(s); and
- The arrangements for trading gas at these point(s).

1.2 With the increase in coal seam gas (CSG) production and the development of liquefied natural gas (LNG) export facilities, the East Coast of Australia is undergoing a significant transition. It is moving from a 'gas island' where gas was locally produced and locally consumed to 'a gas exporting region' where locally produced gas is exported to international markets, mainly in Asia. As such, the East Coast of Australia is experiencing an unprecedented growth in gas demand, as well as potential changes to future gas flow patterns across the region and an increase in prices due to competing demand for gas from other markets.

1.3 In response to these developments, the Council of Australian Governments Energy Council ('COAG Energy Council') published a vision to develop a liquid gas wholesale market in the East Coast of Australia. A liquid wholesale gas market is one where participants can quickly buy or sell the commodity without causing significant change in the price or incurring high transaction costs. As such, it is a market where there are large numbers of buyers and sellers trading/ re-trading sufficient volumes of gas at low transaction costs.

1.4 International experience demonstrates that liquid traded markets can be achieved through different types of markets. Gas can be traded at a physical location on the gas transmission network, often where gas pipelines interconnect; these are known as physical hubs and are the model adopted in the US. Alternatively gas can be traded at a notional point in a wider geographical area, such as an entire gas transmission network or indeed more than one transmission system. This is known as a virtual hub, which is common in Europe.

1.5 Each type of hub has its advantages and disadvantages and will require changes to the current arrangements in the East Coast of Australia. Physical hubs signal the price of commodity at particular locations in the gas transmission network, which allow market participants to respond in the short-term by delivering gas to where it is required and in the longer-term to invest in pipeline capacity to locations with persistently high prices.

1.6 However, physical hubs require large numbers of buyers and sellers to be trading gas at particular points in the gas network. One of the factors of their success in the US is the large numbers of participants at all points in the supply chain: in trading gas, in offering gas pipeline services and in offering hub services (to facilitate gas trading). As such, it may be more challenging to generate sufficient liquidity at physical hubs in markets with a higher concentration of gas traders, pipeline owners and hub operators.

1.7 Virtual hubs seek to address this challenge by covering a wider geographic scope and hence a larger number of market participants. Virtual hubs facilitate trading and promote new entry by allowing participants to trade anywhere within the hub and having an operator manage gas flows within the hub.

1.8 The types of virtual hubs in Europe differ to the Declared Wholesale Gas Market (DWGM) in Victoria in respect of arrangements for transporting gas. In European virtual hubs, participants must book capacity to enter and exit the hub, which assigns participants rights over transportation capacity. The allocation of these capacity rights can be used to signal the need for investment in the pipeline capacity required to reach the hub.

1.9 However, investment in pipeline capacity within the hub is conducted on a centralised basis, often overseen by the regulator. Therefore, the geographical scope of a virtual hub must be carefully considered; there is a trade-off between wider hubs that facilitate gas trading and retaining market signals for investment in pipeline capacity.

1.10 The gas market in East Coast of Australia has both types of hubs; it has physical hubs in Adelaide, Brisbane, Sydney and at Wallumbilla in Queensland and a virtual hub in Victoria. However, the level of liquidity is low at both. Therefore, we recommend the following steps in order to transition towards a liquid gas market:

- Ensure that all market participants able to access the pipelines (and hence the hubs) on transparent, fair and not unduly discriminatory terms. This is particularly important for the SWQP pipeline that connects Moomba to Wallumbilla, given it is the only way of conveying gas between the North and South of the country. We understand that the AEMC is considering this issue further under another work stream);
- Modify the existing virtual hub at Victoria to allocate capacity rights at entry and exit points to the hub;
- Introduce a virtual hub at Wallumbilla, which can be extended to include other pipelines over time, if the benefits are evaluated to outweigh the costs; and
- Harmonise the trading arrangements between the hubs in the East Coast so that market participants face, to a greater extent as possible, identical trading arrangements at all locations in Eastern Australia.

2. Introduction

2.1 In December 2014, COAG Energy Council published a vision for the future of Australia's gas market. It envisaged:

> *"...the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities[1]."*

2.2 The Energy Council has tasked the Australian Energy Market Commission (AEMC) with reviewing the current arrangements in the gas market in the East Coast of Australia and identifying the gaps between the current arrangements and this vision. Using a two staged process, AEMC has published a first report, which identifies the gaps in the current arrangements and makes certain recommendations for immediate implementation. In the second stage the AEMC will develop the medium to longer-term arrangements in order to achieve the Energy Council's vision.

2.3 In relation to the second stage, the AEMC has commissioned FTI Consulting to provide it with advice in relation to the development of liquid gas markets in the East Coast of Australia.

2.4 In particular, the AEMC has asked FTI Consulting to provide options and make recommendations in two specific areas. These are:

- First, the geographical location of trading points for the gas market and the arrangements for accessing these points; and
- Second, the arrangements for trading and balancing gas at these trading points.

2.5 Having established recommendations in these two areas, we have also been asked to consider whether there are any specific measures to be a taken in relation to the transition from the current market arrangements to our proposed approach.

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

2.6 Given this overarching remit, this report sets out our final recommendations to the AEMC. In the remaining part of this introductory chapter we:

- Describe the approach that we have undertaken in deriving our recommendations; and
- Explain how we have structured the rest of our report.

Our approach

2.7 Our approach to developing recommendations for the AEMC has had two central themes.

2.8 First, in developing our recommendations we have drawn on international experience of gas market design. In particular we have reviewed the contrasting experiences of North America and Europe to understand how gas markets have developed. Both regions can cite examples of well-functioning liquid wholesale gas markets – although they have adopted differing approaches.

2.9 However, we would be particularly wary of proposing an approach on the basis of international experience without fully understanding the local market conditions. Therefore, secondly - and most crucially - we have sought to understand the current physical and commercial arrangements of the gas market in the East Coast of Australia and its likely future evolution. To that end, we have:

- Developed an understanding of the current physical and commercial arrangements of the gas market in Eastern Australia;
- Undertaken a number of meetings with the AEMC to verify our understanding;
- Participated in the Gas Review public forum in Sydney on 30 September where we set out various options open to policy makers;
- Met with Government Officials in Sydney and via teleconference on 1 October in which we discussed initial views;
- Met with stakeholders at an industry workshop on 1 October in which we discussed initial views; and
- Had bilateral discussions with particular pipeline operators and LNG exporters in which we had more detailed input on views for future market design.

Structure of report

2.10 Our report is structured into five further chapters. In:

- Chapter 3, we consider in detail the COAG's vision of a liquid wholesale gas market. By understanding the goal and its key characteristics, we can identify the key requirements for a liquid gas market to develop and provide a framework for assessing potential approaches;
- Chapter 4, we summarise our understanding of the main physical and commercial features of the current gas market in the East Coast of Australia. As noted previously, any proposed approach must respect the physical characteristics of Australia's gas system and take into account the current commercial arrangements;
- Chapter 5, we draw on international experience to consider the options for defining trading points in the market and then assess how these options may be applied in the East Coast of Australia;
- Chapter 6, having considered trading points within the market, we explore the options for future gas trading and balancing arrangements; and
- Chapter 7, we set out our recommendations and define the appropriate steps to implement these options.

3. The vision for liquid gas markets in the East Coast of Australia

3.1 In its vision to develop a liquid wholesale gas market for the East Coast of Australia, the Energy Council explained at a high level what it considered to be the characteristics of such a market. In this chapter we expand on this high level vision to consider in more detail:

- The key features of a liquid wholesale gas market; and
- The requirements for ensuring that such gas markets become sufficiently liquid.

The key features of a liquid wholesale gas market

3.2 As is the case with any commodity market, a gas market brings together buyers, those wishing to consume gas or deliver gas to consumers, and sellers, those producing gas or delivering gas on behalf of producers. A market, where gas is actively traded is considered desirable as it is more likely to create reliable price signals. Such price signals, created by the interaction of consumers and producers, are important as they convey important information to all market participants. In particular they:

- **Ensure efficient use of gas in the short-term.** Market prices signal the scarcity of the commodity in the market. A high gas price signals for an increase in gas production and/ or a reduction in consumption. Conversely, low gas prices should reduce production and/or increase consumption and
- **Promote an efficient allocation of capital in the long-term.** A high gas price relative to the costs of production should encourage investment in further production facilities. Equally a high gas price in certain locations, relative to the costs of pipelines to transport gas, should encourage investment in gas pipelines. Conversely a low gas price might provide a signal to consumers (such as power plant producers or LNG exporters) to undertake investments in downstream facilities to increase consumption.

3.3 Short-term efficiency is particularly useful in the context of gas markets as both gas production and consumption are subject to uncertainty; gas production can vary at short notice for technical reasons and gas consumption fluctuates as demand is inherently volatile (as it is partly driven by weather conditions). Hence, a market price signals the gas production required to meet consumption and ensures that when gas is scarce that it is delivered to those that value it most[2].

3.4 Liquidity in trading is vital in order for the market price to be robust and its signals reliable. A liquid gas market can be defined as one where participants can quickly buy or sell the commodity without causing a significant change in the price or incurring high transaction costs.

3.5 As such, a liquid market has the following key characteristics:

- Large numbers of buyers and sellers trading;
- Sufficient volumes of gas being traded; and
- Low transaction costs to trading.

Large numbers of buyers and sellers trading

3.6 Liquid markets would typically be characterised by having several buyers and sellers that are willing to transact. As such, individual trades can be easily satisfied and will not cause the price to change significantly. Where the number of trades is low it may take time to agree a trade and parties with market power may be able to influence the price; as such, the market price is unreliable[3].

Sufficient volumes of gas being traded

3.7 If there are sufficient volumes of gas being traded by several parties, market participants become willing to use the gas price as the basis for future trades; instead of agreeing a price for a future transaction, the parties will simply agree to transact at the future price determined in the market. The ratio of the volume of gas traded to the throughput (known as churn) is often a measure used to assess market liquidity[4].

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2 This is typically referred to as allocative efficiency.

3 It is worth noting that it is not a pre-requisite to already have a large number of buyers and sellers in place before setting up traded markets as new entrants can contribute to liquidity. For example, many European markets began with lower numbers of buyers and sellers and liquidity grew over time.

4 For example if all of the gas consumed is sold and bought once the level of churn is 1. Whereas, if gas is first bought and then resold then the churn ratio increases to 2.

Low transaction costs to trading

3.8 Another feature of a liquid market is that there is a low cost of trading. In liquid markets, the spread between the prices of offers to sell gas and the bids to buy gas is small, which reduces the transaction costs to participants buying and then re-selling gas. Therefore, the spread of prices between bids and offers is another measure of market liquidity.

The requirements for a liquid gas market

3.9 For a liquid market to develop the following requirements need to be met:

- A defined trading point for buyers and sellers to meet and agree transactions;
- Ability to access the trading point on a non-discriminatory basis; and
- Products available at the trading point, which meet market participants' needs.

Defined trading point

3.10 Buyers and sellers meet and trade at points known as hubs. A hub is where the ownership or title of gas is exchanged between market participants. Two types of hubs have emerged: physical and virtual. These can be defined as follows:

- Physical hubs are located at particular geographic point on a gas network. To transact at a physical hub, the buyer and seller must ensure that they can convey the gas to and from that point – typically by entering into arrangements with pipeline owners.
- Virtual hubs, by contrast, are located across a wider geographical area. Buyers and sellers of gas need to arrange to convey gas to the entry points and from the exit points of the hub. Inside the "virtual hub", there is no need for a buyer and seller of gas to arrange for transportation of the gas – a third party, usually known as a system operator, organises for the transportation of the gas within the hub.

Access to the trading point on a non-discriminatory basis

3.11 Whether the hub is physical or virtual, buyers must arrange to transport gas to the hub; the difference only arises once within the hub. Non-discriminatory access to transportation capacity is critical if market participants are to be able to compete. This means that all participants must be able to have access to gas transportation services on the same basis – that is to say, that there should be no undue discrimination[5] in how pipeline capacity is allocated to different market participants. If there are obstacles to accessing transportation capacity, this will inhibit participants' ability to respond to market price signals. These obstacles can include:

- Insufficient physical transportation capacity available between particular locations; or
- Where there is sufficient physical transportation capacity, an inability for some participants to obtain the rights to use the pipeline capacity to transport gas between locations.

Products available at the trading point

3.12 Liquid hubs are able to meet market participants' requirements for gas over different timescales. Market participants have:

- Short-term needs to buy or sell gas for delivery during the gas day or the next day, which are driven by changes in supply and/or demand as well as by requirements on them to balance their inputs and offtakes:
- Long-term needs for the delivery of gas in the future, without being exposed to undue price risk.

3.13 We briefly discuss both short and long requirements.

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[5] Undue price discrimination occurs where the same product is sold for a different price without any objective justification. To avoid this it is not necessary that all pipeline capacity must be sold at the same price. There may be price differences due to differences in the products (i.e. short-term versus long-term products). Also customers may pay different prices for the same product as a result of a pay-as-bid auction.

Short-term needs

3.14 Gas supply and demand is inherently uncertain. Demand may deviate from what was anticipated based on the weather (where gas is used for residential heating) and supply may alter if there are unexpected outages in gas production. As such, it is usual for market participants to need to fine-tune the volumes of gas purchased to meet their actual demand for gas near to real time[6].

3.15 Liquid gas hubs allow all market participants equal access to volumes of flexible gas near to gas delivery in order to balance unexpected changes in gas supply and/or fluctuations in demand. Gas hubs facilitate the trading process by providing some form of product standardisation. This can be through the following means:

- Standardised contracts, which allow market participants to contract bilaterally, without lengthy negotiation; and
- Centralised clearing platforms – in some cases, a clearing house acts as counterparty to both sides of a trade, hence removing the counter-party risk.

3.16 To ensure that all parties can compete on an equal footing in trading short-term, it is also important that there is equal and not unduly discriminatory access to sources of flexible gas, including the capacity to store or withdraw gas from the pipelines (known as line-pack) and gas storage. It is also important that the requirements on market participants to balance their injections and withdrawals into and from the gas pipelines are not unduly discriminatory. By designing the trading arrangements to ensure a "level-playing field" for all market participants, market entry and trading at that point is likely to be encouraged as new participants will believe that they will receive "fair" treatment relative to incumbents. In turn, this will increase the number of market players and volumes traded and, in turn, promote liquidity in the market.

Long-term needs

3.17 Liquid gas markets also provide market participants with access to gas for future delivery. When contracting for future gas deliveries at the hub, buyers and sellers face the risk that the price alters between the time the transaction is agreed and the delivery date of the gas. As such, financial participants play an important role in offering products to manage these risks.

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6 In markets without hubs, gas contracts often provide gas buyers with a degree of flexibility to vary the volume of gas delivered, which assists them in managing changes in demand.

3.18 As financial parties tend not to get involved in the physical delivery of gas, they rely on sufficiently liquid short-term markets in order to be able to trade out their positions before the time of physical delivery[7]. Therefore, as gas markets develop, it is usual to see liquidity first develop in the short-term market before financial products emerge and trading develops in products for future gas delivery.

Conclusion

3.19 A liquid gas market is desirable because it creates a credible market price, which signals both short-term efficiency in allocating gas to where it is valued most and promotes long-term efficiency in investment. A liquid gas market is one where there are sufficient participants, sufficient volumes of gas being traded and low transaction costs to encourage buyers and sellers to trade and re-trade gas.

3.20 At a liquid gas market buyers and sellers have access to: trading points at which they can transact, transportation capacity to the trading point and products which facilitate trading. There are different market designs: physical and virtual hubs, which can meet these requirements; the question is: which arrangements are best suited to the East Coast of Australia?

3.21 In the next chapter, we examine the current characteristics and levels of market development in the East Coast of Australia before considering the options for market design in Chapters 5 and 6.

[7] IEA, Developing a Natural Gas Trading Hub in Asia, Obstacles and Opportunities, 2013

4. The current arrangements of the gas market in the East Coast of Australia

4.1 As we noted in the previous chapter, policy makers' desire to encourage liquidity in wholesale gas markets is borne out of desire to promote short run and long run efficiency. However, any market design will need to take into account the nature of physical characteristics of local gas production, transportation, storage and consumption. For example, what is likely to be suitable for a market with gas production distant from demand connected by a single pipeline may well be different from that which is suitable for a highly meshed gas network.

4.2 Furthermore, following the development CSG production, there is significant investment in LNG export facilities in Queensland, which will fundamentally change the gas market in the region. The East Coast will move from being a 'gas island' where local demand was met by local production to a gas exporting region meeting both local and international demand in Asia. This change in gas demand has potentially profound impacts on the East Coast as it may lead to:

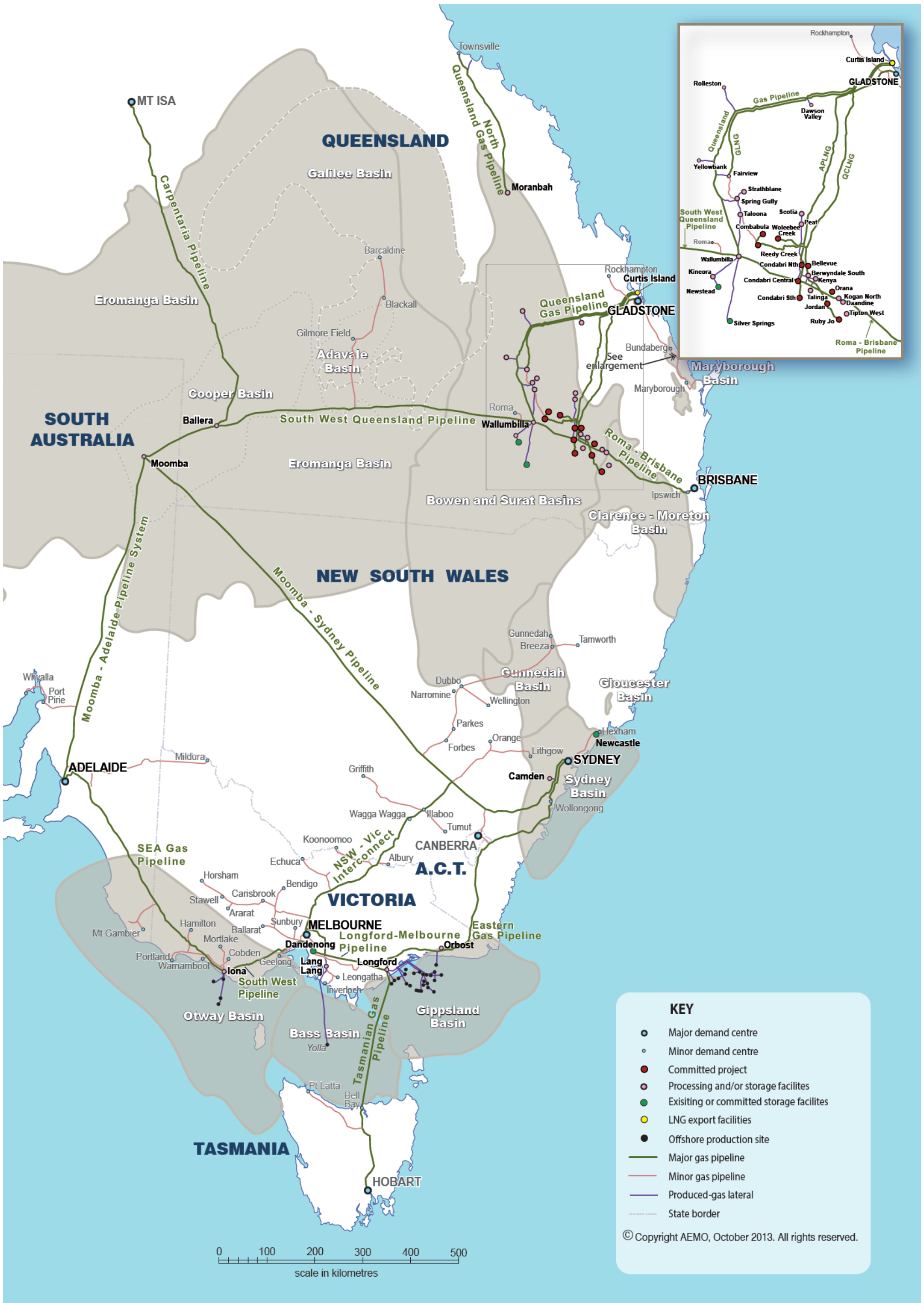
- Increased volatility in demand, as LNG cargoes either fail to arrive and result in excess gas being produced in the East Coast or additional gas being required to satisfy LNG export;
- Changes in gas flows through the existing pipeline networks resulting from increased volatility in demand; and
- Increased prices of gas in the region as gas producers seek to align domestic gas prices with those in long-term oil-indexed contracts with Asian market participants.

4.3 Therefore, the move of the East Coast from a 'gas island' to a 'gas exporting' region creates an impetus for an efficient and liquid gas market.

4.4 In this chapter we summarise the following characteristics of the gas market in the East Coast of Australia:

- The evolution in the gas supply and demand fundamentals driving this change;
- The gas pipeline network and arrangements for market participants gaining access; and
- The main features of current gas trading arrangements.

Figure 4-1: Map of the gas market in the East Coast of Australia



Sources: AEMO, "Map for Eastern and South Eastern Australia", June 2015.

The evolution of gas supply and demand: the transition from Gas Island to Net Exporter

4.5 Domestic gas production in the East Coast of Australia began in the late 1970s. The onshore Cooper Basin in Queensland/SA and the offshore Gippsland Basin in Victoria dominated production until the 2000s. Since 2006, the development of CSG has emerged, most notably from Queensland's Surat-Bowen Basin. The vast majority of reserves (87%) in the East Coast are CSG.[8] This increase in gas production created the impetus for the development of infrastructure to export LNG in Gladstone.

4.6 Ownership of East Coast gas reserves and production from conventional and CSG gas fields is relatively diverse although there are large players, such as Origin, Santos and BHP Billiton that are involved in several fields, as set out in Table 4-1.

Table 4-1: Overview of major gas field basins in the East Coast of Australia

Gas basin(s)	Location	Owner(s)	Type of gas	Supply % to market
Surat-Bowen	Queensland	BG Group Origin Energy ConocoPhillips[1]	CSG	36%
Gippsland	Victoria	ExxonMobil BHP Billiton	Conventional	34%
Otway	Victoria	Origin Energy BHP Billiton Santos	Conventional	15%
Cooper	Queensland SA	Santos Beach Energy Origin Energy	Conventional	13%
Bass	Victoria	Origin Energy AWE	Conventional	<2%

Notes: (1) Other players include Sinopec, Santos, Shell, PetroChina, PETRONAS, Total and AGL Energy.
Sources: AER, "State of the Energy Market", 2014; and FTI analysis.

4.7 As shown in Figure 4-2 below, historic demand for gas has come from: residential heating in Victoria, power generation and industrial sources. Seasonal variation in demand is a feature in the Victorian and New South Wales markets where there is the most demand for gas for residential heating.

8 Eastern Australia contains approximately 36% of Australia's gas reserves.

Figure 4-2 Gas demand by state and sector, 2013

Sources: AEMO, "National Gas Forecasting Report", 2014; and FTI analysis.

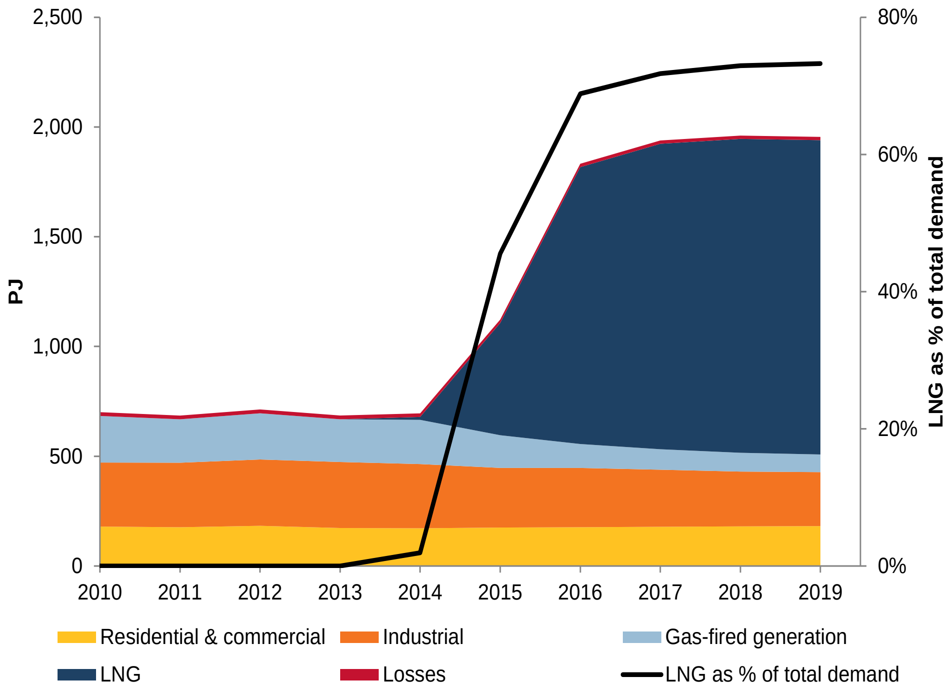
4.8 However, use of gas for industrial purposes and for power generation is set to decline. The development of significant LNG export facilities on Curtis Island in Queensland will fundamentally alter the supply/demand dynamic in the market. Figure 4-3 presents actual and forecast gas demand for the East Coast of Australia from 2010-19. In summary:

- Demand for gas from the three LNG operations being developed at Curtis Island is expected to increase substantially. By 2016 it will account for over 70% of total Eastern Australian demand;
- Residential and commercial demand for gas is expected to remain relatively consistent until 2019, growing at an average of 1.1% per annum;[9]
- Industrial demand for gas is forecast to decline by an average of 3.4% per annum due to closures, e.g. oil refineries in Queensland and NSW; and

9 Retail gas prices in Eastern Australia are unregulated with the exception of NSW, which is expected to deregulate retail gas prices from 1 July 2017: http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0006/579399/Driving-competition-and-transparency-across-the-resources-and-energy-sectors.pdf

- Demand for gas as an input to electricity generation is set to fall an average of 16.8% per annum, due to increasing gas prices leading to coal substitution and limited growth in electricity demand.

Figure 4-3 Actual and forecast gas demand in the East Coast of Australia, 2010-19



Notes: Forecasts are based on the AEMO's "medium" gas consumption scenario. Data from 2010-13 are actual while data from 2014-19 are forecast.
Sources: AEMO, "National Gas Forecasting Report", 2014; and FTI analysis.

LNG exports bring potential changes in flows across the gas pipelines

4.9 Historically, the main centres of demand, except Brisbane, were located in the South. The long-distance[10] pipelines were originally constructed to transport gas from the centres of gas production in Queensland, in the North, to the centres of demand in the South (in Victoria and around Sydney and Adelaide). The exception is the Victoria Declared Transmission System (DTS), a network of pipelines, which transports gas from the fields near Victoria to meet demand in that area.

4.10 With the development of LNG export facilities in Queensland, future demand is likely to be greater in the North than the South. As such, reverse flow capabilities have been, and are being, developed on a number of pipelines e.g. on the Moomba- Adelaide Pipeline, Moomba Sydney Pipeline and Roma Brisbane Pipeline.[11] This will allow gas to be sold from the fields near Victoria, Sydney and Brisbane to LNG exporters in Queensland. It will also open up opportunities for other gas buyers, power plants or industrial customers in the South to sell excess gas to LNG exporters in Queensland.

4.11 As shown in Table 4-2 below, there was sufficient pipeline capacity to meet demand levels in 2014, although congestion may arise on the Eastern pipeline during times of peak demand; as such this pipeline is currently being expanded[12]. However, as there were limited gas flows to LNG facilities in 2014, the impact of increased demand may create future congestion on some of these pipelines.

10 For example, the Moomba to Sydney pipeline is 2,029 km long, while the Moomba to Adelaide pipeline is 1,185 km long

11 AEMO, “Gas Statement of Opportunities”, April 2015, pp. 2-3.

12 See http://jemena.com.au/about/newsroom/media-release/2015/jemena-expands-eastern-gas-pipeline-to-deliver-more

Table 4-2: Pipeline utilisation statistics in 2014

Pipeline	Location	Annual utilisation	Peak daily utilisation
Carpentaria	Queensland	66%	89%
Eastern	NSW	64%	101%
MAPS	SA	48%	99%
MSP	SA-NSW	55%	74%
Queensland	Queensland	89%	97%
RBP	Queensland	74%	93%
SEAgas	SA-Victoria	41%	84%
SWQP	Queensland	28%	79%
Tasmanian	Victoria-Tasmania	26%	47%
Longford-Melbourne (DTS)	Victoria	45%	79%

Notes: Annual utilisation figures are calculated based on the capacity of the pipeline as of 31 December 2015. Daily utilisation figures are calculated based on the capacity of the pipeline on the day that peak demand occurred. Peak daily utilisation can exceed technical pipeline capacity through the use of line-pack. Sources: http://www.gasbb.com.au/Reports/Actual%20Flow.aspx; http://www.gasbb.com.au/Reports/Capacity%20Outlook.aspx; and FTI analysis.

4.12 Pipeline operators invest in transportation capacity on a merchant basis; they bear the commercial risks associated with the investment, which they mitigate through entering into contracts with gas buyers and sellers for pipeline capacity. Market participants buy pipeline capacity to transport their gas to its point of delivery.

4.13 Pipelines are owned by different companies to those buying and selling gas[13]. Ownership of gas transport capacity in Eastern Australia is relatively concentrated, with APA being the largest player and having an ownership stake in over half of the pipelines listed in Table 4-3 below.

[13] With the exception of two of the LNG export pipelines (APLNG and GLNG). However, we understand that, as of August 2015, these two pipelines are for sale, while the third LNG export pipeline (WGP) was sold by its respective gas field producers to APA earlier in 2015

4.14 On most pipelines, but not all, the tariffs for capacity are bilaterally negotiated with network users; there is no requirement to publish these tariffs or apply the same tariff for the same service to all parties[14]. The exceptions are the Carpentaria pipeline and part of the MSP, which are subject to light regulation and required to publish tariffs and terms and conditions for access on their websites[15].

4.15 The exceptions are the DTS and the RBP pipeline, which are subject to full regulation. These pipeline owners must periodically submit an access arrangement to the AER for approval, which must specify at least one reference service likely to be sought by a significant part of the market and a reference tariff for that service. The AER assesses the revenues needed to cover efficient costs and provide a commercial return on capital, then derives reference tariffs for the pipeline.

4.16 The DTS also differs to the other pipelines in the East Coast in terms of physical characteristics. Unlike some of the other pipelines, the amount of gas that can be stored through line-pack in the Victoria DTS is relatively small. Line-pack capacity adequacy for the various pipelines is currently published by the Australian Energy Market Operator ("AEMO") on the National Gas Bulletin Board, with a colour-coded flag system indicating the forecast status of line-pack over the next three days.[16]

4.17 The Gas Bulletin Board operated by AEMO provides information on the availability of spare transportation capacity through links to the pipeline owners' platforms.[17] However, we understand that only a handful of trades had occurred on the APA platform and none on the Jemena platform as of July 2015.[18]

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14 Furthermore ,the three LNG export pipelines (APLNG, GLNG and WGP) are protected from third party access regulation for 15 years

15 A party seeking access to the pipeline may ask the AER to arbitrate.

16 See: http://www.gasbb.com.au/Reports/Linepack%20Capacity%20Adequacy%20Outlook.aspx

17 See: http://www.gasbb.com.au/

18 See page 19 of: http://www.aemc.gov.au/Rule-Changes/Gas-Transmission-Pipeline-Capacity-Trading-Enhance/Pending/AEMC-Documents/Consultation-paper.aspx

Table 4-3: High-level description of major pipelines in the East Coast of Australia

Pipeline	Location	Owner(s)	Regulatory status	Reverse flows	Tariff basis	Capacity (TJ/day)[10]
APLNG[1]	Queensland	Origin Energy ConocoPhillips Sinopec	Protected from access regulation	No	Negotiated	1,560
Carpentaria	Queensland	APA	Light	No	Capacity	119
Eastern	NSW	Jemena	No	No	Negotiated	298
GLNG[2]	Queensland	Santos PETRONAS Total KOGAS	Protected from access regulation	No	Negotiated	1,400
MAPS[3]	SA	QIC	No	Yes[9]	Negotiated	241
MSP[4]	SA-NSW	APA	Light (part of pipeline)	Yes[9]	Capacity and throughput	439
Queensland	Queensland	Jemena	No	No	Negotiated	149
RBP[5]	Queensland	APA	Full	Yes[9]	Capacity and throughput	233 125 reverse
SEAgas[6]	SA-Victoria	APA Retail Employees Superannuation Trust	No	No	Negotiated	314
SWQP[7]	Queensland-SA	APA	No	Yes	Capacity	404 340 reverse

Pipeline	Location	Owner(s)	Regulatory status	Reverse flows	Tariff basis	Capacity (TJ/day)[10]
Tasmanian	Victoria-Tasmania	Palisade Investment Partners	No	No	Negotiated	129
Victoria DTS	Victoria	APA	Full	Meshed network	Injection and withdrawal on throughput	1,350
WGP[8]	Queensland	APA	Protected from access regulation	No	Negotiated	1,410

Notes: (1) Australia Pacific LNG, is for sale as of August 2015; (2) Gladstone LNG, also for sale as of August 2015; (3) Moomba-Adelaide Pipeline System; (4) Moomba-Sydney Pipeline; (5) Roma-Brisbane Pipeline; (6) South East Australia Gas pipeline; (7) South-West Queensland Pipeline including the QSN link; (8) Wallumbilla Gladstone Pipeline (formerly the Queensland-Curtis LNG pipeline); (9) As of August 2015, investment is being undertaken to make the MAPS, MSP and RBP bi-directional; and (10) Capacity as of 24 August 2015.

Sources: AEMC, "Draft Wholesale Gas Markets Discussion Paper", August 2015; AER, "State of the Energy Market", 2014; AEMO, "Gas Statement of Opportunities", http://www.gasbb.com.au/Reports/Standing%20Capacities.aspx; http://www.apa.com.au/our-business/gas-transmission-services/indicative-transmission-tariffs.aspx; http://www.apa.com.au/media/216919/~apa%20gasnet%20-%20remade%202013-17%20aa.pdf; http://energyadvice.com.au/site/wp-content/uploads/Victorian_Gas_DTS_Capacity.pdf; and FTI analysis.

Gas storage

4.18 Gas storage has traditionally been less relied upon as a source of flexibility in the Eastern Australia market when compared with gas field flexibility and line-pack. The majority of storage that has taken place has been via three facilities: Dandenong LNG; Iona; and Moomba (although Moomba is primarily only used by one producer). The price of access to gas storage is also unregulated and is negotiated between buyer and seller.

4.19 With changes underway in the market via the development of LNG facilities and a significant portion of contracted gas supply reaching the end of its term in 2016-17,[19] storage may increase in importance as a means of providing flexibility to meet peaks and troughs (if LNG cargoes are unexpectedly unable to export) in demand. For example, the Newcastle LNG storage facility was commissioned in June 2015.

4.20 Table 4-4 below sets out the high-level characteristics of the gas storage facilities in Eastern Australia, with ownership typically being linked to production and/or LNG facilities.

Table 4-4: High-level characteristics of the gas storage facilities in the East Coast of Australia

Storage facility	Location	Owner(s)	Storage capacity (PJ)	Withdrawal capacity (TJ/day)
Ballera	Queensland	Santos Beach Energy Origin Energy	14	150
Dandenong LNG	Victoria	APA	0.7	238
Iona	Victoria	QIC	22	570
Moomba	SA	Santos Beach Energy Origin Energy	85	32
Newcastle LNG	NSW	AGL Energy	1.5	120
Newstead	NSW	Origin Energy	2	8
Roma	Queensland	GLNG	>50	75
Silver Springs	Queensland	AGL Energy	35	30

Sources: AER, "State of the Energy Market", 2014; Core Energy, "Gas Storage Facilities: Eastern and South Eastern Australia", February 2015; and FTI analysis.

19 Core, "Gas Storage Facilities: Eastern and South Eastern Australia", February 2015, p.4.

LNG exports are leading to changes in domestic contracts

4.21 Gas in the East Coast of Australia has traditionally been supplied under long term gas supply contracts ("LTCs")[20] of ten years or longer between gas producers and large users of gas, (e.g. gas retailers, gas-fired generation plant, mining companies and LNG producers). Long term supply agreements are common when gas markets are first established. They under-write the significant capital investments required in gas production and in pipelines. For example, the development of BG's CSG fields in the Surat-Bowen basin was underwritten by a 20 year LTC with AGL in 2006[21].

4.22 LTCs in Eastern Australia have traditionally included:

- Prices based on domestic market conditions;
- Provisions requiring buyers to take or pay for a minimum volume of gas, usually between 80-100% of the annual contract quantity ("ACQ");
- Daily flexibility of between 100-125%, which adds up to a maximum of 100% of the ACQ; and
- Clauses to allow for price reviews every five years.

4.23 More recently, there has been a move to shorter gas supply contract lengths of up to five years. One example of a shorter length contract is AGL entering into a three year gas supply contract with Esso and BHP Billiton for supply from the Bass Strait, beginning in 2018.[22] It has been reported that:[23]

- **Between 2002 and 2009**: 11 out of 12 contracts signed were for durations greater than five years in length and only one contract up to five years;

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20 In April 2015, the Australian Competition and Consumer Commission ("ACCC") began an investigation into whether insufficient competition is driving up wholesale gas prices in eastern Australia. The inquiry under Part VIIA of the Competition and Consumer Act 2010 is considering factors such as the availability and competitiveness of offers to supply gas, the competiveness and transparency of gas prices and access to gas transportation. See: https://www.accc.gov.au/regulated-infrastructure/energy/east-coast-gas-inquiry-2015

21 See: http://www.asx.com.au/asxpdf/20061205/pdf/3zyrfwngg7zf8.pdf

22 See: http://www.agl.com.au/about-agl/media-centre/article-list/2015/april/agl-secures-gas-supply-until-2020-with-bass-strait-agreement

23 EnergyQuest and K Lowe Consulting, "Gas Market Scoping Study: A report for the AEMC", July 2013, p. 41.

- **Since 2010**: around 40 per cent of contracts signed were up to five years' length (10 contracts out of the 26 signed).

4.24 In addition, there are reductions in the degree of flexibility offered in the more recently signed gas supply contracts; yet prices are increasing due to the move to align the contracts with the pricing mechanisms in export markets in Asia[24]. Approximately 60% of the Eastern Australian contracts that have been signed since 2010 involve some level of oil-indexation, typically 6-9%; this includes all of the LNG contracts.[25] Therefore, as LNG exports increases, domestic buyers find themselves with potentially higher prices (depending on the level of oil prices) and less flexibility to vary the volumes of gas deliveries. This drives the impetus for more short-term trading of gas in order to meet the flexibility and take advantage of more market based prices.

Limited trading at current gas hubs

4.25 While there are five gas hubs in the region, the vast majority of trades occur through long-term bilateral contracts outside of these markets[26]. There are also differences in arrangements at the five hubs. Trading is centrally managed and mandatory in Victoria and on the short-term trading markets (STTMs), in the sense that all participants shipping gas to or withdrawing gas from the hub must submit price-quantity pairs on a daily basis, irrespective of whether an actual trade between different parties takes place; whereas trading takes place on a voluntary and continuous basis at Wallumbilla. The main features of the facilitated markets are summarised in Table 4-5 and can be summarised as follows:

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[24] See http://accc.gov.au/media-release/the-importance-of-adequate-competition-for-the-east-coast-gas-market

[25] Data from EnergyQuest from 2013 and K Lowe Consulting, "Gas Market Scoping Study: A report for the AEMC", July 2013, p. 41.

[26] AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, Executive Summary, page ii

- **Declared Wholesale Gas Market ("DWGM"):** A virtual hub that covers the Victoria Declared Transmission System ("DTS"), where it is mandatory to bid into the market (rather like an electricity pool). The market operator, AEMO, matches the bids to the cheapest offers until all of the demand is satisfied; the price at which the market clears sets the ex-ante price. AEMO produces a schedule for gas flows, which shippers can use to nominate flows. Trading effectively ceases prior to real time and AEMO manages any imbalances after gate closure; the costs of which are passed onto network users. Shippers do not explicitly book capacity to transport gas within the DTS; instead they agree to pay the transmission tariffs for accessing the system determined by AER and capacity is implicitly allocated by AEMO based on the scheduled quantities. The DWGM was established in 1999 to support retail competition and to provide a mechanism to resolve daily gas imbalances in a transparent and competitive manner;
- **Short Term Trading Markets ("STTMs"):** Physical hubs based in each of Adelaide, Brisbane and Sydney, where again trading is mandatory. In these markets the bidding process is similar to the DWGM but only takes place on a day-ahead basis rather than several times intra-day. These hubs were established in 2010-11 to facilitate the short term trading of gas and support retail competition; and
- **Gas Supply Hub ("GSH"):** A physical hub located at Wallumbilla in Queensland, where several pipelines interconnect. It was introduced in May 2014 to facilitate trading close to gas production centres.[27] Trading at this hub is voluntary and takes place on a continuous bilateral basis. The hub provides trading participants with an electronic platform to trade standardised, short-term physical gas products. AEMO matches the trades and centrally settles transactions but unlike the DWGM or STTMs, it does not schedule and manage gas flows or balance inputs and offtakes on the gas pipelines.

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27 A further Gas Supply Hub could be operational in 2016 at Moomba, SA.

Table 4-5: High-level characteristics of the gas hubs in the East Coast of Australia

Characteristic	DWGM	STTMs	GSH
Location	Victoria DTS	Adelaide, Brisbane & Sydney	Wallumbilla
Physical or virtual	Virtual	Physical	Physical
Allocation of transport capacity	Implicit allocation	Booked by shippers	Booked by shippers
Mandatory or voluntary	Mandatory pool	Mandatory pool	Voluntary exchange
Matching of bids and offers	Five biding period per day	Day-ahead	Continuous
Shippers	41	20	8

Sources: AEMC, "Draft Wholesale Gas Markets Discussion Paper", August 2015; AEMC, "RfP – Virtual gas hub design", July 2015; AER, "State of the Energy Market", 2014; and FTI analysis.

4.26 The AEMC's Stage 1 Report included an assessment of each of the facilitated markets. The AEMC noted that market participants consider the STTM and DWGM hubs have largely provided an effective and competitive gas balancing service. Some participants have also found the STTM and DWGM useful as a way of initially entering the gas market before committing to bilateral gas supply and transportation agreements[28].

4.27 According to the AEMC's Stage 1 Report, the DWGM and STTM hubs have also been criticised for complexity, inability to manage risk and extra cost.

- **Complexity:** the pool design of the gas trading hubs has resulted in complex operational procedures and the various adjustments ex-post lead to the potential for high charges ex-post. Some market participants have suggested that the STTMs should be simplified to become balancing platforms[29].

28 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 112

29 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 99-100

- **Inability to manage risk:** For shippers on both sides of the transaction, the risk of price volatility is managed. However, where genuine trades take place between different counterparties on the hubs there are no financial products available to manage this price risk in the STTMs[30] and while derivative products linked to the price at the beginning of the day are available in the DWGM these are rarely traded[31]. Furthermore, the derivatives do not hedge against any uplift charges in the DWGM[32], which can be smeared across all users and not controllable by shippers. Also, the ex-ante price does not cover all of the costs[33], which makes it difficult to develop risk management products[34].
- **Extra Cost:** There appear to be large fixed costs associated with operating the STTM and DWGM hubs. The mandatory nature of the STTMs and DWGM means that market participants incur direct costs of trading on the hubs despite the fact that most trading between different counterparties occurs outside of these hubs.

4.28 In parallel to the work on the overall design of market arrangements in the East Coast, the Energy Council at the request of the Victorian Government has also commissioned a review of the DWGM to consider whether its objectives and design need to be amended. One focus will be on the pricing mechanism of the DWGM and measures to improve liquidity. Another focus will be to examine the potential to introduce capacity rights to the DWGM, with the objective of better facilitating market-led investment in network expansion. The AEMC's Stage 1 report concluded that allowing participants to signal the need for capacity augmentation would be likely to result in more efficient investment, and would transfer risk away from consumers to parties better able to manage it[35].

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30 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 101

31 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 131

32 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 131

33 In DWGM there are additional ancillary payments, which are payable if AEMO has had to procure a more expensive source of gas to balance the system

34 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 132

35 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 144

4.29 AEMO is holding a consultation process[36] in order to develop arrangements to enhance hub services to facilitate gas trading at the GSH. Currently, gas cannot freely flow between the three pipelines at Wallumbilla; as such trading is split between the different pipelines and facilities, which divides potential buyers and sellers and limits trading liquidity[37]. The services being considered include:

(1) *Intra-hub transfer service:* the transfer of gas from one interconnected pipeline to another through a connection/header (hub), by displacement (including exchanges), or by physical transfer.

(2) *Title transfer service:* an accounting service that allows the permanent transfer of gas ownership from one party to another.

Conclusion

4.30 The East Coast of Australia is moving from being a ‘gas island’ where gas is produced to meet local demand to a ‘gas exporting’ region. This significant increase in gas demand has important impacts on:

- Future gas demand volatility;
- Future gas flows within the system; and
- The contractual arrangements for trading gas; where contract duration is shortening and prices are increasing as a result of being aligned with those in Asian markets.

4.31 Investment in reverse flows is underway to allow gas produced in the South to be sold to LNG export terminals in the North. However, it is possible that as LNG exports increase over time, transportation capacity will become scarce. As such, it is important that:

[36] See: AEMO, “Wallumbilla Single Product: High Level Design Report”, June 2015 and Draft Report, October 2015.

[37] AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 150

- Existing capacity is used efficiently and can be obtained on a not unduly discriminatory basis by all market participants to allow responses to changes in demand and supply; and
- Future arrangements signal the need for investments in transportation capacity.

4.32 The current arrangements have incentivised significant investment in pipeline capacity[38] undertaken by private companies with no risks (of stranded assets or cost overruns) borne by final consumers. In making any proposals to enhance liquidity on the East Coast of Australia it will be important that the future arrangements continue to facilitate investment in pipeline capacity. However, unlike arrangements in Europe and the US, where tariffs for transportation capacity are transparent, not unduly discriminatory and subject to regulatory oversight, there is a risk that market participants in the East Coast are perceived to be paying different tariffs for the same service. This may particularly deter new entry by shippers with smaller gas portfolios, who, unlike a large buyer, may consider that they do not have the market power to negotiate a good deal. The perception of this risk is as important as the actual risk. In other words, even if, in practice, shippers are being charged the same tariff for the same service, if they perceive that they may not be then this may be sufficient to deter new entry.

4.33 Furthermore, AEMC's Stage 1 Report concluded that it intends to consider the barriers to secondary trading of transportation capacity. While the opportunity costs associated with capacity potentially being booked but not used might be low if there is sufficient capacity available, this may not be the case as future demand increases and transportation capacity becomes potentially scarce.

4.34 In addition, as the long-term contracts are offering reduced flexibility in light of the potential future export to Asian markets, demand for short-term transportation capacity may increase as shippers seek additional capacity in order to manage inherently volatile demand. Therefore, ensuring that any barriers to accessing booked but unused transportation capacity are removed, such that all market participants have access to this capacity on a not unduly discriminatory basis, will be important in stimulating short-term gas trading.

4.35 Therefore, it is becoming increasingly important to make the vision for traded gas markets in the medium to long-term a reality. In the next Chapter we assess the options for designing gas trading hubs, which will facilitate the transition in the East Coast towards a liquid gas wholesale market.

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38 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, Executive Summary, page iii

5. Hub design options for the East Coast of Australia

5.1 International experience demonstrates that it is possible to achieve liquid gas markets through different designs in gas hubs. Henry Hub in the US has different arrangements to the National Balancing Point (NBP) in Great Britain or Title Transfer Facility (TTF) in the Netherlands, all of which set the reference prices in their respective markets.

5.2 There are two main types of hubs: physical and virtual, which differ by being located:

- At a particular physical point, usually where gas pipelines interconnect; or
- Virtually, to encompass a wider geographical scope.

5.3 In this chapter, we review the international experience in implementing physical hubs in the US and virtual hubs in Europe. We begin the chapter by examining physical hubs before considering virtual hubs. We structure each section to:

- Describe the main features of the type of hub;
- Assess the main advantages and disadvantages of each type of hub; and
- Highlight the main changes that would be required to the current arrangements in the East Coast of Australia in order to implement each model.

Main features of physical hubs

5.4 A physical hub is a geographical point in the gas pipeline network where a price is set for gas delivered to and transferred from that location. Physical hubs are often located at points where several pipelines interconnect or where gas processing sites or storage is located.

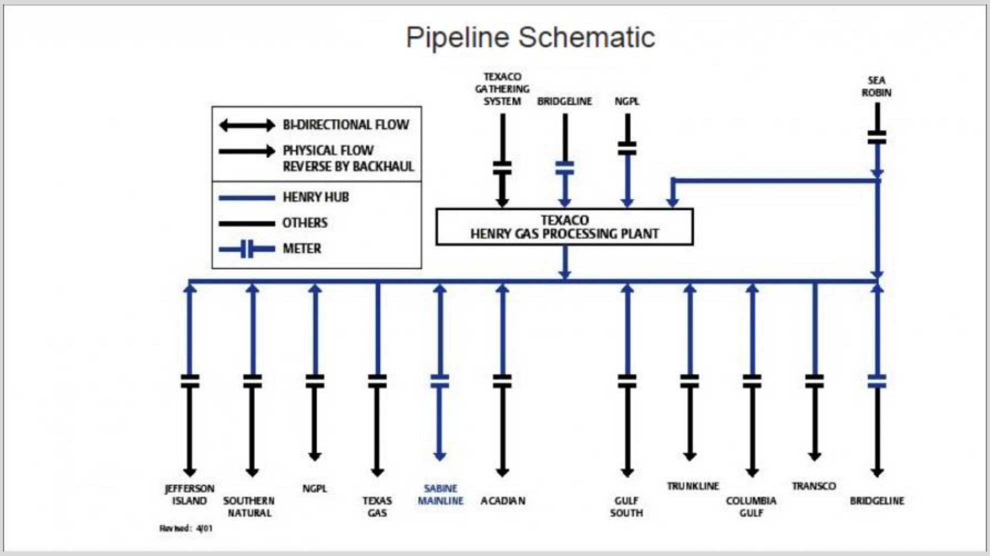
5.5 Physical hubs tend to be used in North America where there are approximately 200 physical hubs in various locations linked by interstate pipelines. The most well-known is the Henry Hub in Louisiana, which sets a benchmark price for the US gas market and is used for trading financial products on the New York Stock Exchange (we present information on the Henry Hub in Box 1 below).

Box 1. The Henry Hub

The Henry Hub is a physical gas hub based in South Central Louisiana. It is the dominant benchmark in the US gas market because of its strategic location in the Gulf Coast's producing area and the number of pipeline connections to key consumption areas.

The Henry Hub comprises 13 interstate and intrastate pipeline connections, a processing plant and gas storage facilities, as depicted in Figure 5-1.

Figure 5-1 Henry Hub pipeline schematic



Sources: ICE.

The Henry Hub is therefore a relatively complex network of pipelines, many of which are located significant distances away. To act as a single physical hub, the market design of Henry Hub involves:

- Regulation that allows all of the pipelines to operate as a single system;
- An accounting mechanism called the Intra-Hub Transfers ("IHT") that records all title transfers and ensures that a trader's purchases equal its sales (unless physical delivery is desired); and
- An operational balancing agreement with all interconnecting pipelines, which places responsibility for balancing on the pipeline owners so that individual shippers do not incur imbalance penalties.

The Henry Hub is highly liquid. The average volumes of Henry Hub gas futures contracts traded on the NYMEX is approximately equal to 43 times the daily U.S. dry gas production from January to July 2015.[39]

A defined trading point where buyers and sellers transact

5.6 In the US, the Federal Energy Regulatory Commission (FERC) promoted the development of market centres to provide market participants with services to facilitate gas trading. Market centres are defined as an area where a) pipelines interconnect and b) there exists or there is reasonable potential for developing a market institution that facilitates the free interchange of gas. Market centres have three main aims.[40] These are to:

- Provide short term/ short haul transportation services that allow market participants to move gas between pipeline systems;
- Provide the means to increase short term exchanges between parties to allow market participants to balance and manage their portfolios; and
- Offer a means to reduce price risk exposure

5.7 We briefly discuss short haul transportation services and short term exchanges below and consider how to reduce price risk exposure in Chapter 5.

Short-haul transportation services

5.8 Being able to transfer gas between interconnected pipelines at the hub is essential in promoting gas trading. Without this service, gas trading is limited to gas trades on a particular pipeline. To transfer gas between pipelines in the US, market participants pay the market centre a switching fee to organise the transfer of gas either by way of exchanging gas on one pipeline with the equivalent volume on another or through physical transfer.

Increase short-term exchanges

5.9 In order to promote trading, FERC issued Order 637 to reduce the impact of imbalance penalties, which has led to market centres offering a number of balancing services. Pipeline operators are required to provide, to the extent operationally practicable, services such as:

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39 See https://rbnenergy.com/henry-the-hub-i-am-i-am-what-really-drives-liquidity-at-the-US-natural-gas-benchmark

40 EIA, "The Emergence of Natural Gas Market Centers: Issues and Trends", 1996.

- Parking, a short term service to hold gas using line-pack or storage; and
- Lending, a service to advance gas from line-pack or storage for a short term to be repaid later.[41]

5.10 The services are managed by two parties:

- The centre administrator who liaises with the market participants and undertakes administrative tasks;
- The pipeline operators who carry out the operational tasks of transferring gas.

5.11 The exact services offered at market centres are determined by the needs of the participants at the particular location. An overview of the types of services offered is set out in the information box below.

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41 In the US, market centres have also formed where gas production or gas storage meets the pipeline system. These market centres also offer the ability to access storage capacity and park gas for periods of time. EIA, Office of Oil and Gas - April 2009, page 2.

Box 2. The types of services offered at hubs[42]

The types of services offered by hubs vary significantly. No two operations are identical in the services offered, and in fact, the features of similarly named services often differ in meaning and inclusions. The list below describes most of the broad types of services offered.

Transportation/Wheeling: Transfer of natural gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over the transmission of a hub pipeline.

Parking: A short-term transaction in which the hub holds the shipper's natural gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in line-pack.

Loaning: A short-term advance of natural gas to a shipper by a hub that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.

Storage: Holding natural gas longer than parking, such as seasonal storage. Most often confined to available interruptible storage capacity only.

Peaking: Short-term (usually less than a day and perhaps hourly) sales of natural gas to meet unanticipated increases in demand or shortages of natural gas experienced by the buyer.

Balancing: A short-term interruptible arrangement to cover a temporary imbalance situation. The service is often provided in conjunction with parking and loaning.

Pooling/Volume Aggregation: A pooling transportation service that allows customers to aggregate natural gas from various points within a supply area and have it delivered into downstream firm or interruptible transportation contracts at designated delivery point pooling stations.

Title Transfer: A service in which changes in ownership of a specific natural gas package are recorded by the hub. Title may transfer several times for some natural gas before it leaves the hub. The service is an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic Nomination: Customers may connect with the market centre electronically to enter natural gas transportation nominations, examine their account position, and access bulletin board services. Such systems may also facilitate trading among buyers

42 EIA, "Natural Gas Centres", 2008 update.

> and sellers and support direct negotiation among parties.
>
> **Administration:** Assistance to shippers with aspects of natural gas transfers, such as nominations and confirmations.
>
> **Compression:** Provide compression needed to increase pressure of natural gas received off of a lower pressure system so that it can be transferred to a pipeline operating at a higher pressure. If needed additional compression is bundled with transportation, it is not a separate service.
>
> **Hub-to-Hub Transfers:** Arranging simultaneous receipt of a customer's natural gas into a connection associated with one hub and simultaneous delivery at a distant connection associated with another hub.

5.12 The costs of hub services are determined by market demand and constrained by competition with other hubs. Rates for the services are published and charged on a non-discriminatory basis. The exception is inter-state transportation services that, as described in greater detail below, have rates that are approved by the FERC. Market centres have been deactivated when demand for services at particular points diminishes[43]. New market centres can also emerge. For example, with the discovery of Shale gas, there is new demand for a market centre in the Marcellus region.[44]

Access to the market centres and trading between them

5.13 At many market centres there are two means of trading between hubs. These are:

- Hub-to-hub transfers, which allows the market participant to buy gas into a pipeline connection associated with one market centre and receive delivery at a connection associated with another centre.
- Buying capacity on the relevant pipelines to transport gas between the hubs.

5.14 Hub-to-hub transfers allow market participants to trade between hubs without booking separate transportation capacity. This service is managed by the pipeline operators through a combination of exchanges of gas between locations, storing gas or transporting gas between hubs.

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43 For example, the Spindletop Storage Hub in Texas was deactivated in 2004 due to it being too expensive for the volumes of gas that were being traded there. See: EIA, "Natural Gas Centres", 2008 update.

44 For example, the Marcellus Eastern Access Hub was developed in 2008. See: http://www.downstreamtoday.com/(X(1)S(d2bksdinlchd5v555deuqp45))/projects/Project.aspx?project_id=128

5.15 Alternatively, market participants can book the transportation capacity to access the market centre. Once at the market centres, participants are responsible for buying capacity with pipeline operators to transport gas from point A to B and redirecting flows within the hub.

5.16 Pipeline capacity is built in the US by private companies, which following the FERC Order 436 are prohibited from transporting their own gas through the pipelines. Pipeline operators sell capacity on a firm or on a discounted interruptible basis according to published rates. The rates are set according to zones, the charge for injecting and withdrawing gas in the same zone are lower compared to rates for injecting in one zone and withdrawing in another. Users can nominate a primary delivery point and switch to a second delivery point in the same zone[45].

5.17 The rates for inter-state pipelines are approved by FERC to ensure against them being 'unreasonable'. However, in approving the rates, FERC will place importance on rates that have already been negotiated and agreed with market participants.[46]

5.18 The availability of pipeline capacity is published on an electronic bulletin board along with the prices for secondary trades, between shippers, in transportation capacity. Price ceilings for secondary capacity trading were initially removed in 2000[47] and finally in 2008[48] but the prices for these trades between participants are published, allowing full transparency. Ceilings on the rates that shippers could charge for secondary capacity were originally introduced because FERC considered that the extent of

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45 Pipeline transportation rates can be priced on zones or miles, or be a fixed postage stamp rate. In zonal pricing, the price of transportation varies by the location of the receipt and delivery points, across a series of zones. See: http://www.ferc.gov/market-oversight/guide/energy-primer.pdf p. 25.

46 See: https://opsweb.phmsa.dot.gov/pipelineforum/docs/Ratemaking%20for%20Energy%20Pipelines%20071111.pdf and http://www.ferc.gov/market-oversight/guide/energy-primer.pdf

47 In 2000, FERC Order 637 implemented the following five changes into its regulations: i) removal of the price cap on secondary pipeline capacity sales; ii) requiring pipeline companies to permit shippers to "segment" capacity for their own use or release. Segmenting broke up capacity into separate segments in a complete chain, to facilitate using some and releasing others; iii) limiting imbalance management and penalty provisions only to those needed to protect system reliability; iv) consolidating and enforcing pipeline reporting requirements to improve price transparency and more effective monitor the exercise of market power; and v) requiring "incremental pricing" for all new pipeline transport capacity. See: http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm98-10.pdf

48 FERC Order 712, see: https://www.ferc.gov/whats-new/comm-meet/2008/061908/G-4.pdf

competition may not sufficient in order to ensure that the rates would be just and reasonable[49].

5.19 In summary, market centres in the US meet the main requirements for liquidity to develop. They provide:

- Trading platforms which signal the price of gas at physical locations on the system; this not only promotes trading but acts to provide signals for infrastructure investment; and
- Access to the hubs on transparent and non-discriminatory terms, which create a level-playing field for competition.

The assessment of physical hubs

5.20 There are certain advantages and disadvantages with the US approach to physical hubs.

5.21 The main advantage of the US-style market is that it is market led with regulatory oversight rather than intervention. The services offered at market centres are those required by the market participants at that location. The locations at which market centres emerge are driven by market demand. The investment in pipelines is by private, unbundled operators, who bear the investment risks and have an incentive to maximise the capacity offered and innovate services.

5.22 Therefore, the regulator's role is mainly ex-post monitoring rather than significant ex-ante regulation (other than ensuring that transportation tariffs are not 'unreasonable'). However, for this to work the right regulatory framework needs to be in place in order to ensure that all buyers and sellers have equal and non-discriminatory access to transportation capacity. As such, there are two key regulatory requirements in the US, which act as the cornerstones to promoting competition, these are:

- Pipeline operation and ownership is unbundled from those using the pipelines to buy and sell the gas; this ensures that pipeline owners have no incentive to withhold capacity, which might arise if they were allowed to transport their own gas; and

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49 FERC Order 636, see explanation in FERC Order 712, page 6 para 8, https://www.ferc.gov/whats-new/comm-meet/2008/061908/G-4.pdf

- Transparent and non-discriminatory tariffs for pipeline capacity and hub services as well as regulatory oversight of transportation tariffs; this not only ensures that all participants have access to the same service at the same price but ensures that there is a perception of all shippers being able to access the same tariffs, which is critical to promoting competition and small-scale new entry.

5.23 The other advantage of the US market design is that it signals to pipeline investors the need for additional investment in pipeline capacity. It does this in the following ways:

- Persistent price differences between hubs suggest that additional capacity may be profitable between these locations; and
- Transparency in prices for existing transport capacity and its usage signal the value and potential scarcity of capacity at that location.

5.24 It also ensures that, once built, capacity is used efficiently. By selling transport capacity as a price per zone, the US model promotes competition in secondary capacity trading, often charging a postage stamp (i.e. a flat, uniform charge) to transfer gas within a zone. Market participants, who have booked transport capacity, which they do not wish to use, are more likely to find a buyer for that capacity on the secondary market than if the capacity were restricted to delivery at a particular delivery point.

5.25 However, the main reason this approach is successful in the US is that there are low levels of concentration in all parts of the supply chain: pipeline owners, hub operators, shippers and customers. As such, there are large numbers of buyers and sellers at many US market centres and there is often competition between the pipeline routes and hubs to transport gas between different locations. This diversity in market participants is important as it:

- Leads to greater liquidity to emerge at the hub as more participants are active in trading and re-trading gas; but also
- Incentivises competition in pipeline and hub services, which leads to innovative products, such as hub-to-hub services, being developed and this enhances gas trading.

5.26 Therefore, to deliver liquid trading and credible price signals, physical hubs, as developed in the US, have required large numbers of buyers and sellers willing to trade and competition between pipeline owner and operators to provide hub services.

Implementing physical hubs in the East Coast of Australia

5.27 There are certain similarities between the characteristics of the US pipeline network, which features long-distance pipelines to transport gas from the centres of production to demand, and much of the pipeline infrastructure in the East Coast outside of Victoria. In particular, the following parallels with the US can be drawn at Wallumbilla or Moomba, where:

- Several pipelines interconnect and there may be a need for market participants to trade gas, particularly with the expected increase in gas transfers between the North and South of the region;
- Different private companies own the pipelines in these locations and pipeline ownership is unbundled from the gas buyers and sellers; and
- In the case of Wallumbilla gas hub, options are currently being explored to introduce a range of standardised services to facilitate gas trading[50].

5.28 However, the main difficulty is that market participation in the East Coast of Australia is significantly more highly concentrated than at the market centres in the US. Notable differences between the US gas market and that of the East Coast of Australia are:

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[50] See: AEMO, "Wallumbilla Single Product: High Level Design Report", June 2015 and Draft Report, October 2015.

- First, there are only a few pipeline owners with competing transportation routes. Instead, most of the pipelines link different locations. This is likely to dampen the incentive to compete in providing transportation services (although may facilitate the coordination required at physical hubs to facilitate trade);
- Second, there is one market operator which, by virtue of its not for profit status, may have a less strong incentive to innovate in developing hub services[51]; and
- Third, there are a small numbers of shippers, (currently there are around 12 registered shippers at Wallumbilla). This is likely to reduce the demand for short-term gas and increase the incentive not to release booked but unused transportation capacity. The number of shippers may increase once new arrangements are introduced but it remains to be seen whether sufficient liquidity can develop if trading is at this one location.

5.29 Furthermore, in Victoria the system characteristics are quite different. In fact, the DTS network resembles much more the types of transmission systems seen in Europe. The main features can be summarised as:

- Network of pipelines; currently flows are redirected across the system and AEMO manages physical constraints; as such, it may be more efficient for a single entity to undertake this role than for individual shippers to buy services to re-route gas; and
- Trades currently occur in the DWGM across the entire network; splitting trading between physical points on the system, such as Longford and Iona, where pipelines interconnect, may be less likely to promote liquidity.

5.30 If physical hubs were introduced, it would require significant change to the current regulation of the tariffs for pipeline capacity. Many of the pipelines are unregulated and there is no transparency or oversight of the tariffs being charged to shippers.

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51 As AEMO is not-for-profit it is unable to keep any additional revenues that it may earn from product innovation. Furthermore, unlike market centres in the US, it does not face competition from other market operators, which may also dampen its incentive to innovate. However, this may be mitigated, to a certain extent, by the duties and obligations placed on AEMO by governments and industry to develop liquid markets.

5.31 While the required unbundling of pipeline ownership removes any incentive on pipeline owners to withhold capacity, it does not remove pipeline operators' incentives (or at least the perception of pipeline owners' incentives) to extract maximum rents from those using the pipeline. A large shipper buying significant volumes of transport capacity may have negotiating power but smaller shippers may perceive that they pay higher prices or obtain less favourable terms for the same service. This is likely to deter new entry into the market and distort competition. It seems likely, therefore, that regulatory oversight of transportation tariffs and a requirement on all pipeline operators to have greater transparency on tariffs charged to shippers would be important were liquidity at physical hubs to be enhanced.

5.32 Greater regulation than seen in the US of the types of products and services offered by pipeline operators and hub operators may also be necessary. The lack of competition in pipeline routes, the not for profit nature of AEMO and the small number of incumbent shippers, who may not all require hub services (as they hold sufficient transportation capacity and gas to manage their portfolios) may dampen the impetus to develop innovative pipeline and hub services. This could include:

- Requirements that pipeline operators resell booked but unused capacity[52], if there is a high concentration of incumbent shippers, who are unlikely to resell unused capacity on the secondary market;
- Regulatory oversight of the prices for released capacity products and of short-term capacity, in order to ensure that new entrants can gain fair and non-discriminatory access to short-term capacity;
- Specification of the hub services to be offered to allow participants to balance their portfolios, regulatory oversight of tariffs for hub services and requirements on AEMO to contribute to developing liquid hubs; and
- Requirements on pipeline operators to cooperate in developing hub services. This would be akin to examples from the EU where there are requirements on transmission system operators (TSOs) in neighbouring countries to cooperate in order to facilitate cross-border trade[53].

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52 We understand that there is a separate work stream considering this question.

53 Regulation 715/2009 of 13 July 2009 on conditions for access to the natural gas transmission network repealing Regulation 1775/2009, Article 5. See: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0715&qid=1445616077371&from=EN

5.33 Therefore, in summary, it is important to determine whether physical hubs are likely to bring together sufficient buyers and sellers. If the East Coast of Australia opts for physical hubs increased regulatory oversight of pipeline and hub services seem, to us, necessary to ensure that all market participants can gain access to the market on fair and not unduly discriminatory terms.

Main features of virtual hubs

5.34 An alternative approach is to pool gas trading over a wider geographical area rather than at one particular node on the system. A virtual hub is a trading point for an entire network of gas pipelines, or indeed more than one network, where there is a single price for all trades of gas within the area regardless of the particular location within the hub.

5.35 Unlike the market centres in the US, virtual hubs are often determined by regulators, in consultation with industry through a process of market design. The main international examples of liquid virtual hubs are in Europe:

- The National Balancing Point (“NBP”) in Great Britain; and
- The Title Transfer Facility (“TTF”) in the Netherlands.[54]

However, the level of trading and liquidity is developing at the other hubs in Western Europe including Net Connect Germany (“NCG”), Point d’Echange de Gaz (“PEG”) in France and the Punto di Scambio Virtuale (“PSV”) in Italy.

Defining a trading point for buyers and sellers to transact

5.36 Transmission networks within Member States in Europe are often highly meshed. A virtual hub allows for market participants to trade at any points on the meshed system(s).The geographical scope of the virtual trading points in Europe can vary. It may cover the following:

- The boundary of a single transmission system; for example, the NBP in Great Britain covers all of the gas trading between market participants at any points on National Grid’s gas transmission system across the entirety of Great Britain;

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54 In 2014, the TTF overtook the UK NBP as the most liquid hub and this trend continued in 2015. In the first quarter of 2015, traded volumes at the Dutch hub increased by 44% year-on-year while they were flat at the NBP. See: DG Energy, "Quarterly Report on European Gas Markets”, 1Q 2015, p. 22.

- several multiple transmission system networks; for example, the new NCG formed on 1 October 2011 covers six transmission systems in Germany owned by different operators, which includes: Bayernet, Fluxys TENP TSO, GRT gaz Deutschland, Open Grid Europe, Terranets and Thyssengas; and
- Part of a transmission system; for example, PEG Nord and PEG Sud were established as separate hubs in France due to insufficient transport capacity on GRT gaz's transmission system between the North and the South of the country. However, following a programme of pipeline investment, plans are currently underway to merge these hubs to create a single market within France.

5.37 As is the case with physical hubs in the US, virtual hubs in Europe provide the possibility to transfer the title of gas between market participants. However, at a virtual hub, the transmission system operator (TSO) manages flows between pipelines within the network. The TSO's management of flows between pipelines or different parts of the network within the hub is automatically provided and costs are spread across all hubs users, usually in the tariffs for transmission capacity, although some hubs charge separate fees for hub services.

Access to the hub and trading between hubs

5.38 As such, market participants are not required to book transportation capacity within the hub; this is managed by the system operator. However, in European virtual hubs market participants are required to book capacity in order to access the hub. The difference compared to physical hubs is that transportation capacity to access virtual hubs is booked at points where gas enters and exits the transmission system(s) covered by the hub.

Booking transportation capacity to access virtual hubs

5.39 Entry points to a virtual hub are those where gas is injected onto the transmission network and include connections with:

- Gas processing facilities from production fields;
- Pipelines in non- EU countries (such as points where Russian gas is delivered to the EU border);
- LNG re-gasification terminals; and
- Storage sites.

5.40 Exit points are where gas is withdrawn from the transmission network and include connections with:

- Large industrial sites or power plants, owned by customers, who take gas directly from the transmission system;

- Distribution networks, which are used to transport gas at low pressure to end-customers; and
- Storage sites.

5.41 In a fully functioning entry-exit system, users are not required to match the entry capacity booked with equivalent exit capacity. The concept is that gas brought onto the system at any entry point can be made available to market participants wishing to off-take gas at any exit point.

5.42 There are also points which interconnect the gas transmission systems between different virtual hubs. These points are known as interconnection points ("IPs"), where gas both enters and exits the transmission system. Users must also book capacity at IPs to transfer gas between hubs; they must book capacity to exit one transmission network and capacity to enter the neighbouring hub.

5.43 The European network codes have introduced a number of measures to facilitate access to capacity at IPs; lack of available transportation capacity between Member States transmission systems was one of the barriers to developing liquid gas markets in Europe[55]. The requirements include:

- Entry and exit capacity from each system to be sold as a bundled product[56] (i.e. exit capacity from hub A is sold as bundled product with entry capacity to hub B and vice -versa);
- The capacity at IPs is auctioned using a common platform[57]; this is to ensure non-discriminatory access to capacity and that tariffs reflect the scarcity value of pipeline capacity (i.e. if capacity is scarce it is awarded to the participant willing to bid the highest and values it the most);

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55 The perceived problems with competition in the gas markets prompted the European Commission to launch a sector inquiry covering the gas industry in 2005. The final report of the sector inquiry, published in 2007, showed that there were serious distortions of competition in the sector, in particular a lack of liquidity and limited access to infrastructure prevent new entrant suppliers from offering their services to the consumer. See: http://ec.europa.eu/competition/sectors/energy/gas/gas_en.html

56 Commission Regulation 984/2013 of October 2013 'Establishing a Network Code in Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation 715/2009, Article 19. See: http://www.entsog.eu/public/uploads/files/publications/CAM%20Network%20Code/2013/EC_131014_CAM%20NC_Regulation%20984-2013.pdf , Article 19

57 In response to this requirement a number of TSOs joined together to create the PRISMA capacity trading platform. See: https://www.prisma-capacity.eu/web/start/

- Standardisation of the capacity products to cover both long-term and short-term needs; TSOs are required to auction multi-annual, annual, quarterly, monthly, weekly, daily and within-day capacity[58]; and
- TSOs must resell any booked but unused entry/ exit capacity at IPs on the common platform[59].

Setting Tariffs at entry and exit points in virtual hubs

5.44 As capacity is not sold along contractual routes from point A to point B within a hub, then capacity tariffs can no longer be defined purely on cost per distance travelled basis. Instead tariffs are set for each individual entry and exit point on the transmission system. The level of the tariffs is such that they, in aggregate recover the revenues required by the TSO to recover the costs of owning and operating the network of pipes within the virtual hub.

5.45 Where capacity is auctioned, as is the case at IPs, the tariffs that are set determine a reserve price for the auction. A reserve price is a minimum price at which any market participant must bid in order to obtain capacity. When there is more network capacity available than demand (as is currently the case in Europe and may be the case in parts of the East Coast where demand is declining) demand for transportation capacity is typically satisfied at the reserve price.

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58 Commission Regulation 984/2013 of October 2013 'Establishing a Network Code in Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation 715/2009, Article 9.1 See: http://www.entsog.eu/public/uploads/files/publications/CAM%20Network%20Code/2013/EC_131014_CAM%20NC_Regulation%20984-2013.pdf

59 There are two approaches that TSOs may use: firm use-it-or-lose where the original capacity owner effectively loses his rights to the unused capacity. Alternatively there is or oversubscription and buyback where the TSO sells capacity that is booked but likely to be unused. Both shippers (the original owner and the shipper who has bought capacity rights to the unused capacity) retain capacity rights. If this 'overbooking' leads to the potential for excess flows on the system, the TSO is able to buy-back capacity by holding an auction for shippers to offer to sell capacity. Compensation is paid for the lost value associated with the trade. Commission Decision of 24 August 2012 amending Annex 1 to Regulation 715/2009 on conditions for access to access of the natural gas transmission networks, Articles 2.2.2 and 2.2.3 See: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32012D0490&from=EN

5.46 Therefore, the first step in setting tariffs for entry-exit capacity is to determine the revenue that pipeline operators need to recover from their investments. In Europe, the national regulator generally determines the revenue that the TSOs are allowed to recover for the provision of their network services.[60]

5.47 The second step is to determine the type of cost that is being recovered and the pricing methodology used to allocate the costs to the different entry-exit points. Entry-exit tariffs can either be set to recover the average or the marginal cost of capacity. These can be summarised as:

- Average costs are the total costs incurred by the TSO divided by the volume of capacity.[61] This approach aims at recovering the actual costs of investments already incurred. Where no growth is expected in demand, recovering the costs according to previous investments may be appropriate.
- Where significant growth in demand is expected and capacity is expected to be scarce and additional investment in capacity likely, then it may be more appropriate to seek to recover the costs of the prospective costs of satisfying additional demand, i.e. long-run marginal costs (LRMC). In so doing, this influences siting decisions of those wishing to enter or exit the virtual hub.

5.48 The postage stamp model can be used to recover average costs by dividing the total revenue to be recovered with the total volumes of capacity at the entry-exit points. This results in a uniform price per unit of capacity being applied at each point on the system. This has the advantage of being straightforward but does not give any locational signals for the investment in capacity.

5.49 A matrix approach is used when setting tariffs to signal future demand and recover LRMC. A matrix of all of the potential combination of routes between various entry and exit points on the networks is established. The following approach is then applied:

- Calculate the LRMC of satisfying an additional unit of demand along each transport route (i.e. between each entry and exit point) in the matrix;

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60 There are some gas pipelines, whose revenue is not determined by the regulator and the gas pipeline, known as a merchant pipeline, bears the risk. However, the regulator must still approve the tariffs charged by such pipeline unless they obtain an exemption from third party access provisions. These include the Interconnector UK, which connects Great Britain with Belgium, and BBL, which connects Great Britain and the Netherlands. These pipeline owners are remunerated by the sale of capacity to market participants – the price of which typically reflects the expected price spread between the two markets.

61 Transmission networks are built to accommodate peak winter flows so total capacity is defined by assessing the peak flows over the system in the coldest winter over 20 or 50 years.

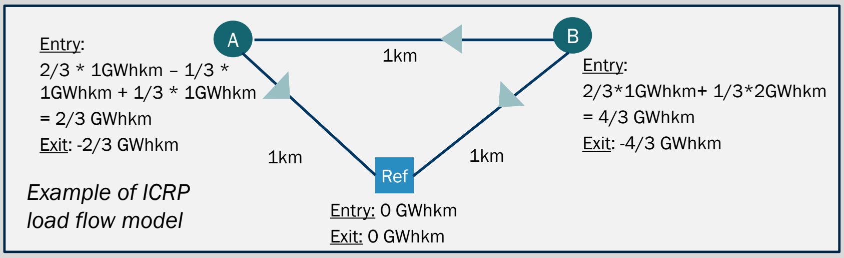
- Take each entry point as a starting point and allocate the LRMC to providing additional capacity on the route to each exit point; if there is more than one route to an exit point, then allocate the lowest LRMC to each exit point as it would be efficient to increase capacity on the route with the least cost hence if there are alternative routes;
- Take each exit point as a starting point and repeat the same process to allocate the LRMC to the entry points; this may result in negative tariffs (e.g. if the LRMC of allocating additional capacity from A to B is 5 then the cost of allocating additional capacity from B to A is –5 as this essentially requires a decrease in gas flows from A to B));
- Check that for every route the combined entry and exit charges add up to the LRMC; and
- Adjust the negative tariffs by adding the same positive value to all tariffs to obtain positive values, (this keeps the relativities between the tariffs the same and removes negative values, which removes the need for the TSO to pay market participants for reverse capacity flows).

5.50 Box 3 below provides a stylised worked example of the approach used to set entry and exit tariffs based on the approach used in Great Britain.

Box 3. Stylised example of setting entry and exit tariffs

Calculating locational entry and exit tariffs requires a load flow model to assess how changes in gas demand at a particular location would impact on the overall cost of the network. In Great Britain, National Grid, as TSO is responsible for calculating the tariffs and uses a load flow model known as DC ICRP (Direct Current Incremental Cost Related Pricing) and is based on a similar approach used to calculate electricity transmission tariffs.

Assuming a stylised 3 node network as set out below:



In this network there are three nodes, A, B and the reference node (Ref) each connected by 1 km of pipeline. The load flow model calculates the typical flow on the network. In this case, gas enters the network at node B. Some of the gas flows to the reference node and some flows to node A. Furthermore, gas also flows between node A and the reference node (as indicated by the arrows).

The load flow model assumes that the network is sized to meet the current level of demand. It then calculates the impact of meeting an additional unit of demand (this is 1 GWh) at the reference node by considering how much more pipeline capacity would be required if the gas were to enter the network at a specific node. This calculation is undertaken for each node on the network.

Assuming, first, that the incremental unit of gas enters the network at Node B, the model would calculate that to serve the one unit of additional demand of gas at the reference node, two thirds of the unit of gas would flow along the pipeline direct to the reference node. However, because of a tendency for pressure to equalise the model also assumes that one third of the gas would flow to the reference node via Node A. To accommodate this additional unit of gas, the model would therefore calculate that there would be a two thirds of a unit increase for the one km of pipeline connecting B to the Reference Node (2/3 GWhkm) and a one third of a unit increase for the two km of pipeline connecting the B to the reference Node via Node A (1/3GWhkm + 1/3GWhkm = 2/3GWhkm). Overall, in this example, therefore, the overall amount of incremental pipeline capacity required to meet an additional 1 GWh of gas demand at the reference node from Node B would be 4/3 GWhkm.

The same calculation is then performed for Node A. The model would again assess that two thirds of the gas would flow directly from Node A to the reference node and one third of the gas would flow the longer route via Node B. The calculation of incremental pipeline capacity required to serve the increment of demand at the reference node would be as follows:

- The pipeline between Node A and the reference node would need to be expanded by two thirds of one unit for the 1km of its length
- The pipeline between Node A and Node B could be *reduced* by one third of one unit as the gas flow along this pipeline is contrary to the original assumed flow.
- The pipeline between Node B and the reference node would need to be increased by one third of one unit to allow the flow between Node B and the reference node.

In aggregate therefore, because gas flow is assumed to be contrary to the typical direction of travel for gas on this network on the pipeline segments A to B, the overall incremental capacity to meet the demand of an additional unit of gas at the reference node is 2/3GWhkm of pipeline capacity.

Intuitively, the model has assessed that the impact of entering the gas system at Node A would be to use “less” of the network than if it were to enter at Node B.

The next step is to multiply each derived nodal expansion factor by an assumed cost per unit of pipeline capacity. Hence, if we assume that the expansion constant is $10GWhkm, then the entry tariff at Node A would be $6.66 per GWh, at Node B would be $13.33 per GWh and at the Reference Node would be $0 per GWh. It is further assumed that exit tariffs are the negative of these.

These tariffs are the derived long run marginal cost of entering and exiting the system. However, a final step must be performed to ensure that the amount of revenue that will be recovered through the tariffs is consistent the overall amount of revenue that the TSO is allowed to recover by the regulator. This is known as scaling. A number of possible approaches are used, but a favoured approach is to increase each tariff by the same absolute quantum so that the price difference for each tariff is retained.

If we assume that 10 GWh of entry capacity is required at Node A and at Node B to meet demand of 20 GWh at the Reference Node, then, on the basis of the tariffs, calculated this would recover $200. If, however, we assume that the network owner needs to recover $400 to cover the costs of its network (as most probably agreed with the regulator) then all tariffs would be scaled to ensure that amount of revenue is recovered. In this case, all tariffs would be $5GWh so that the final tariffs for entry would be $18.33 per GWh at Node B, $11.66 per GWh at Node A. Exit tariffs would be $5 per GWh of capacity at the Reference Node.

Reallocating revenues between different pipeline owners

5.51 Where more than one transmission network is covered by the entry-exit system then it is necessary to re-allocate the collected revenues from selling transportation capacity to ensure that each TSO recovers its investment costs and earns a return.

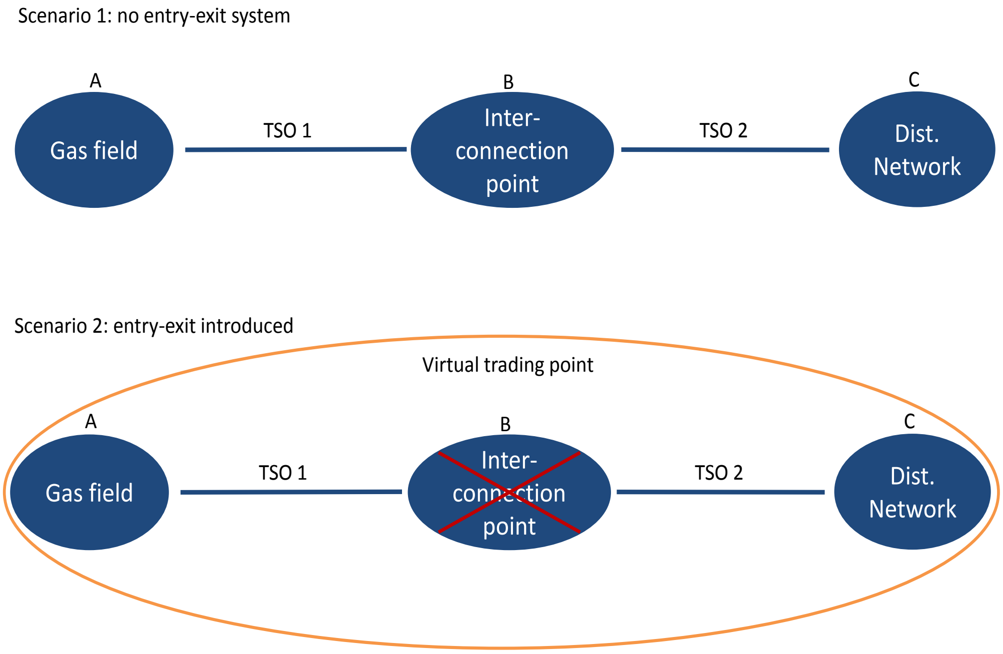
5.52 This is necessary as merging previously separate transmission systems into one entry-exit system may lead to alterations in gas flows and change TSO revenues. Merging systems leads to points that were previously entry-exit points between two systems becoming an internal point within the network at which capacity is no longer booked. This may lead to additional capacity being booked at other entry or exit points in each of the transmission systems. As such, one TSO may generate additional revenue following the merger of hubs while another may lose revenues.

5.53 In Figure 5-2 we present a simple diagram to demonstrate the potential impact of merging entry-exit systems.

5.54 In summary,

- **In Scenario 1:** There is no entry-exit system. TSO 1 earns revenue from charging shippers to transport gas from the gas field (point A) to the exit point onto the neighbouring transmission system (point B). TSO 2 earns revenue from selling capacity from point B to the interconnection with the distribution network at point C.
- **In Scenario 2:** An entry-exit system is introduced that incorporates the two pipelines into the one entry-exit system. TSO 1 earns the revenues from the entry tariffs at point A but no exit revenues. However, point B is now an internal point in the entry-exit system and point C is an exit point on TSO 2's network. Given that market participants can now flow gas directly between point A and C, this may lead to more capacity being booked at A in order to sell C or indeed other exit points in TSO 2's network or vice-versa. Therefore, this may alter the revenues collected by the TSOs.

Figure 5-2: Simple diagram of the impact of introducing entry-exit system



The Assessment of Virtual hubs

5.55 As is the case with physical hubs, there are certain advantages and disadvantages with virtual hubs.

Virtual hubs facilitate gas trading

5.56 The main advantage of a virtual hub is that it facilitates gas trading. By allowing market participants to trade anywhere within the hub without having to book the pipeline capacity to transport the gas between particular points, it reduces the transactions required to trade gas for actual delivery. This is a particular advantage on highly meshed networks, where there may be several nodes at which capacity bookings may otherwise be required.

5.57 By facilitating gas trading virtual hubs may also be particularly beneficial to small new entrant shippers. At the time of introducing the requirement to establish entry-exit systems, the European Commission noted that it should benefit new entrants:

> *'...as they could book capacity without specifying beforehand where this gas should go. They allow for the development of notional balancing points, where entry gas is brought to a virtual point in the system, from which point the same or other network users can transport to an exit point. The notional point can thus become a trading hub, and serve as a balancing point in network users' portfolios as well as TSOs to source its balancing gas.*[62]

5.58 Virtual hubs also pool a wider number of buyers and sellers, who deliver gas to different points on the transmission network. Widening the geographical scope to cover a larger number of entry/ exit points and requiring TSOs to manage flows within that area enhances market liquidity. For example, NCG is one of the fastest growing in Europe with total title transfers rising by approximately 50% from around 1.3 million GWh in 2011/12 to around 1.9 million GWh in 2014/15.[63] Some of this increase in trading can be attributed to the merging of several transmission systems into one virtual trading point that occurred in 2011.

Virtual hubs can signal the need for investment

5.59 The approach to additional pipeline investment in markets with virtual hubs will depend on whether the investment is required within the hub or outside of it.

5.60 Outside of a virtual hub, investment in pipeline capacity is driven by the standard commercial investment signals to investors – that is the opportunity for price arbitrage between an area of low priced gas and high priced gas. Hence, an investor with access to low priced gas may wish to invest in pipeline capacity to connect to the virtual hub.

5.61 However, because virtual hubs cover wider geographic areas, investors in pipeline capacity connecting to a virtual hub entry or exit point face a choice of which specific point to connect to at the virtual hub. This provides the rationale for locational variations in entry and exit prices – areas where a new pipeline would not trigger significant investment within the hub to cater for increased flow tend to have low prices whereas areas that are likely to incur significant cost in meeting the additional flow are likely to have higher prices.

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62 Commission staff working document on capacity allocation and congestion management for access to the natural gas networks regulated under Article 5 of Regulation (EC) 1775/2005 (SEC) 2007 822, 12 June 2007, page 7.

63 See: https://www.net-connect-germany.de/en-gb/Information/Balancing-Group-Managers/Virtual-Trading-Point/Development-of-Trading-volumes

5.62 Within a virtual hub, by virtue of the fact that there is only one price and hence no price signals to respond to, then it follows that standard commercial approaches to pipeline investment can no longer apply. Instead, investment is undertaken by the TSO to expand capacity to ensure that gas can flow within the virtual hub without causing excessive congestion costs. Typically, this requires approval from the regulator to agree that the proposed TSO investment within the virtual hub is reasonable and hence that the costs of the investment should be recovered through entry and exit tariffs.

5.63 The GB regime uses auctions for entry capacity as a signal for incremental investment within the virtual hub. Should auctions for long term entry capacity signal that there is greater demand for entry capacity than can currently be provided by the configuration of the pipeline network, this signals the potential need for investment. Under the GB approach, should the auction for long term entry capacity recover 50% of the incremental cost of delivering new pipeline capacity within the hub this triggers investment in new pipeline capacity within the hub. The entire costs of the investment are recovered from entry and exit tariffs.

5.64 Because there typically is only one participant that might offtake at a given exit point there are usually no auctions for exit capacity. Hence, different rules apply. If additional exit capacity is required, the party off-taking the gas requests the capacity and, moreover, commits to pay the prevailing exit capacity charge at that node for a number of years. This provides reassurance to the TSO, and in turn the regulator, that the party requesting the additional exit capacity will pay the appropriate charges.

5.65 A particular nuance of the GB regime is that exit points are defined anywhere within, or on the perimeter of, the geographic footprint of the NBP, and a shipper may request exit capacity at any point on the system. This is true irrespective of whether the physical exit point is from a lower pressure distribution network or the higher pressure national transmission system. Prior to 2005 all of the gas distribution networks as well as the National Transmission system were owned by a single company. Hence, to the extent that there existed choices between investing in higher pressure transmission system pipelines or distribution pipelines to meet demand for exit capacity in a distribution network, such trade-offs were internalised within one company.

5.66 However in 2005 some of the gas distribution networks were sold to third parties so that there was fragmentation between the ownership of the gas transmission system and some of the gas distribution networks. Because investment in distribution pipelines and transmission pipelines are, to some extent, substitutes, this raised the possibility of distortions in investment decisions. In particular, there was a risk that distribution network owners demanded greater use of the transmission system rather than incur costly investment on their network and vice versa.

5.67 To resolve this issue a relatively complex set of incentives have been introduced that incentivises distribution network owners to consider the cost of transmission pipelines when making operational and investment decisions. It does this in the main by exposing the distribution network owners to some of the cost of the transmission system tariffs calculated through the ICRP methodology discussed above. As these vary by location the distribution network is, in part at least, incentivised to consider whether it is better to incur the cost of additional investment in its own distribution network or face the higher costs under incentive scheme of using more of the transmission system.

Cost and regulation of virtual hubs

5.68 The main disadvantage of a virtual hub is the potential cost of managing gas flows within a wider geographical area and the regulation required to set tariffs.

5.69 If a hub is designed to include parts of a network, where there are physical constraints in the transport capacity available, this creates challenges in scheduling flows within the entry-exit system. It can lead to the pipeline operator reducing capacity at various entry/exit points in the network in order to manage the constraint, which could undermine the flexibility of the entry-exit scheme and potentially increase costs. For example, in some European hubs capacity continues to be offered on a point-to-point basis so is effectively kept outside the virtual hub or capacity may be offered in certain locations only an interruptible basis.[64]

5.70 In Figure 5-3 we present a simple diagram of a virtual hub. It shows a network, with entry points A, B and C and exit points D and E. We assume that pipelines A- E and C- D can each transport 2 units and pipelines B- E and B- D can each transport 1 unit. When moving to a virtual hub pipelines operators need to agree on the volume of entry capacity to sell at each entry point and at each exit point.

5.71 In order to maximise capacity, pipeline operators may wish to sell 2 units of entry capacity at each point A, B and C and 3 units at the exit points D and E. However, given that shippers buying entry capacity do not have to specify the exit point for the gas, there is a risk that a shipper buying the 2 units of entry capacity at B will wish to flow both units to either point D or E. However, there is insufficient capacity on pipelines B- E and B- D to flow more than 1 unit of gas. Therefore, the system operator may offer less capacity at entry point, i.e. 1 unit of capacity.

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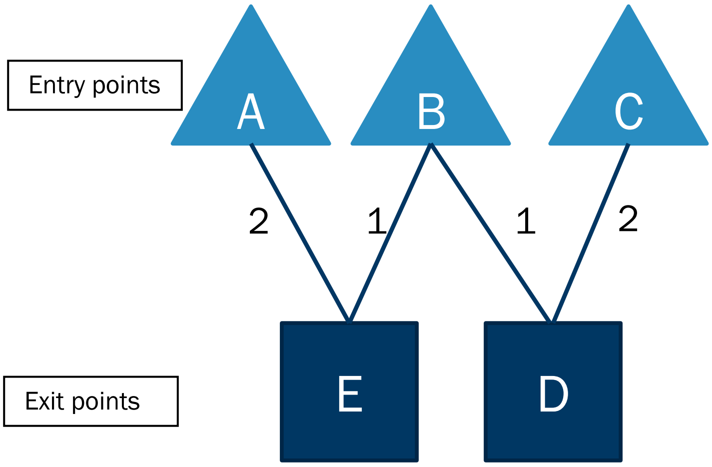
64 KEMA and COWI, "Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems".

Figure 5-3: Managing capacity at virtual hubs



5.72 One approach to resolving this issue is to define separate virtual trading hubs for the two parts of the network. In Figure 5-3 above, this could mean having one hub with entry points A and B and exit point E and another hub with entry points B and C and exit point D. When there is sufficient transport capacity between the two hubs, the gas prices would converge. When there is insufficient transport capacity the price at the hub with higher demand than supply would increase. This increased price would signal to the market the need for increased transportation capacity.

5.73 The other approach would be to oblige (and/or incentivise) the system operator to continue to sell 2 units of capacity at Node B. In the event that the market participant at Node B decided to ship capacity in a way that breached the physical limits of the network (i.e. by nominating to flow more than one unit of gas on either pipeline B-E or B-D) then the system operator would need to buy back that capacity from the shipper at the prevailing market rate. This is likely to be a loss making trade – in that the price originally paid for the capacity may well be lower than the price the TSO needs to pay to buy back the capacity. The costs of this trade are typically recovered from all customers in the virtual hub through a smeared charge.

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

5.75 The European virtual hubs require greater ex-ante regulation than the physical hubs in the US. Not only are the tariffs for transportation capacity made transparent but regulatory oversight extends to the methodology used by TSOs to calculate tariffs. This is required in order to ensure that the tariffs derived provide non-discriminatory access to all market participants. Regulatory oversight is also likely to be required where a single hub covers several pipeline owners and it is necessary to have a means to reallocate the revenues collected between the TSOs.

5.76 Furthermore, the process of setting entry-exit tariffs is arguably more complex than setting tariffs based on distance travelled; it involves modelling of gas flows. The complexity is further increased if there is more than one TSO covered by the same entry-exit system.

5.77 There are advantages and disadvantages to virtual hubs. These can be summarised as, virtual hubs:

- Provide market participants with flexibility to trade anywhere within the hub without having to book capacity or manage their flows;
- Signal the need for investment in pipeline capacity to the hub but not within the hub; and
- May lead to higher costs or reduced capacity being made available on the pipelines, in order for TSOs to manage flows; and
- Require a more complex process and regulatory oversight in setting tariffs as investment in pipeline capacity within a virtual hub will be subject to a regulatory approval. This issue is further complicated if it involves several pipeline owners.

Implementing virtual hubs in the East Coast of Australia

5.78 As is the case with physical hubs, implementing virtual hubs in the East Coast of Australia would require change to the current arrangements. However, the degree of change required is different in Victoria, where a virtual hub already exists, compared to the rest of the region.

Changes to current arrangements to implement virtual hubs

5.79 The Victorian DWGM is a virtual hub, which shares some of the characteristics found in European entry exit systems. The DTS is:

- A network; as such gas flows are redirected across the system and AEMO manages physical constraints, which may be more efficiently managed by a single party;
- Subject to full regulation and, owned by one operator; which facilitates the calculation of entry-exit tariffs by setting a separate tariff for capacity to enter and exit the DWGM hub and allocating capacity rights. While investment is happening on the DTS, price signals would provide more reassurance that there is real demand for the investment.

5.80 As such, the change for the Victorian DWGM in introducing entry-exit tariffs would be more straightforward than on other parts of the East Coast network. The main issue to resolve would be the grandfathering of the rights over the previously allocated Authorised Maximum Daily Quantity (AMDQ).

5.81 There is a greater difference between current arrangements elsewhere in the East Coast and those associated with virtual hubs. As such, a virtual hub would require more substantial changes. These include:

- Transport capacity would need to be allocated on the basis of entry-exit points instead of on the basis of distance; this would require considering whether to grandfather the rights in the existing legacy transport contracts[65] or whether to allow some distance-related contracts to persist for a transitional period;
- Tariffs for transportation capacity would need to be calculated for entry-exit points and would need to be published;
- Most pipelines would require regulatory oversight and the agreement of revenues that should be recovered as part of the methodology required to calculate entry-exit tariffs;
- A mechanism to redistribute revenues between pipeline operators would need to be developed, where there is more than one pipeline operator within the same virtual hub; and
- A party would need to be tasked with managing flows across pipelines; this could be done by defining a separate third-party system operator or through pipeline operator cooperation.

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65 In some countries in Europe, some legacy contracts were allowed to persist after the introduction of entry-exit arrangements, so were essentially carve outs from the entry-exit arrangements for a period of time.

Geographical scope of virtual hubs in the East Coast

5.82 The exact extent of these changes depends on the geographical scope of the virtual hub or hubs defined. As described above, there is a trade-off between widening the geographical scope to enhance trading liquidity and the costs and complexity involved in managing flows across a larger area. When defining the geographical scope of potential virtual hubs in the East Coast of Australia, there are two important considerations to take into account, which are:

- Whether there are likely to be frequent occasions when there is a physical constraint (i.e. insufficient transport capacity to meet all of the demand at a particular price) within the transmission network(s), which would restrict the flow of gas to certain locations; and
- Whether the entry-exit system is intended to cover transmission networks owned by different pipeline operators and whether these operators are subject to different types of regulation.

5.83 We understand that there is a potential for a future physical constraint between the North and the South once LNG exports increase. If such congestion is likely, this may point to delineating future hubs between the North and the South of the East Coast of Australia. This would ensure that market prices would continue to signal the need for additional pipeline capacity between the separate hubs and avoid potentially costly buying back of capacity. Yet, at the same time, the arrangements for access would be more likely to promote liquidity.

5.84 However a Northern and Southern hub will mean that several pipeline owners are covered in each hub. As depicted in Figure 5-4, there are key intersection points in the East Coast of Australia network where different pipeline owners meet.[66] The two hubs could be defined as:

- The Northern hub covering RBP, Wallumbilla, Moomba and the pipelines to the North; and another
- The Southern Hub covering all pipelines South of Moomba.

5.85 In a potential Northern hub revenues would need to be re-distributed between pipeline operators at certain entry or exit points. These are:

[66] In a theoretical "southern virtual hub" the key ownership intersection points relate to Adelaide, Sydney and Tasmania. In a theoretical "northern virtual hub" the key intersection points relate to Wallumbilla, although with the proposed sale of two of the LNG pipelines there may be further such points in the future.

- **Wallumbilla:** where pipelines owned by APA and Jemena meet; and
- **Gladstone:** where pipelines owned by APA and Jemena offtake gas.

5.86 In a potential Southern hub, revenues would need to be re-distributed between pipeline operators at the following entry or exit points. These are:

- **Moomba:** where pipelines owned by APA and QIC would enter or exit the hub;
- **Adelaide:** where pipelines owned by APA and QIC offtake;
- **Sydney**: where pipelines owned by APA and Jemena offtake; and
- **Tasmania**: where pipelines owned by Jemena and Palisade meet.

5.87 To remove the complexity of setting tariffs across several differently owned pipelines in the one entry-exit system, hubs could be more narrowly defined to cover only one pipeline operator. For example, this could be:

- The Northern hub covers only the RBP pipeline; and
- The Southern covers only DTS in Victoria.

5.88 While such a definition removes some of the complexity that arises from managing several pipeline operators within the hub, by reducing the geographical scope, it reduces the buyers and sellers who will trade at the hub.

5.89 Therefore, it will be important to strike a balance between covering a sufficient area in order to attract sufficient shippers to trade at the hub with the costs of managing flows in that area and the regulatory change required to define a wider entry-exit system.

5.90 Taking into account the two considerations - the physical constraints and the difference in pipeline ownership - a staged approach could be used to introduce virtual hubs in the East Coast. The staged approach can either be bottom-up where the hub begins as a narrowly defined hub and expands to include other networks over time. Alternatively, a top-down approach can be used where a larger area is defined but certain points are exempted from the entry-exit system for a certain period of time.

5.91 These options can be summarised as the following:

- Bottom-up: The Southern hub initially covers the DTS in Victoria and expands over time to include the pipelines connecting Sydney, Adelaide and Moomba subject to gaining sufficient comfort about managing the costs of any increased congestion arising from expansion of the hub. The Northern hub initially covers RBP and Wallumbilla, which already brings together several pipeline owners, and expands over time to include Moomba and pipelines at Gladstone. The costs and benefits of expanding the hubs to include certain pipelines could be modelled in order to avoid that the costs of including certain locations do not outweigh the benefits.
- Top-down: The Northern hub spans all networks from Brisbane to Moomba and further North. The Southern hub encompasses all of the networks South of Moomba, including the Victorian DTS, Sydney and Adelaide. However, initially certain locations could be carved out from the entry-exit system[67].

5.92 In summary, implementing one or more virtual hubs in the East Coast of Australia will require significant change to the current arrangements. The wider the geographical reach of the hub, the more it pools buyers and sellers, which contributes to liquidity. However, the wider the geographical area, the higher the risk of greater costs from managing gas flows and the more complex the regulatory arrangements.

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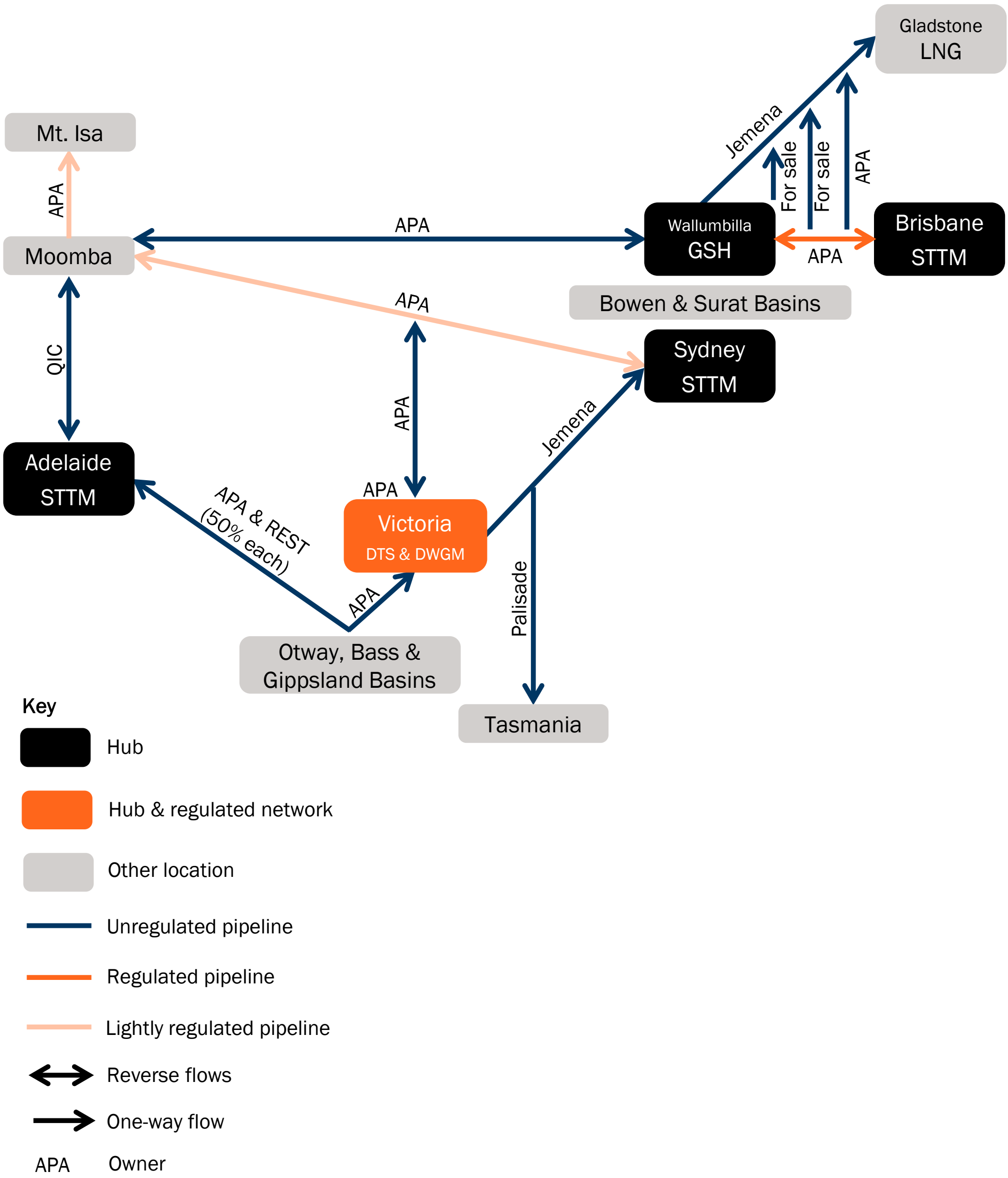
67 As discussed above, in some countries, the pipeline operators place restrictions on certain transportation routes, such as requiring point-to-point capacity sales for some routes or only offering as available capacity on these routes. Such arrangements should be restricted to where they are necessary to manage physical constraints or where legacy contractual arrangements impede the introduction of entry-exit arrangements.

Figure 5-4: Stylised map of the East Coast Australian gas market showing ownership, regulation and flow



Source: Table 4-3; and FTI analysis.

6. Options for trading and balancing arrangements

6.1 Having explored the options for location and access to the hub, the next question is how gas is traded at the hub. As briefly explained in Chapter 3, trading occurs on a voluntary and bilateral basis in Wallumbilla and through a mandatory centrally-cleared platform on the STTMs and in Victoria. It is concentrated in a certain time period (day-ahead or at certain points within day) in the latter and is continuous in the former. The decision on the trading arrangements is, to a large extent, independent of the decision on whether to have a virtual or physical hub.

6.2 The trading arrangements provide market participants an opportunity to buy and sell gas either with other market participants or, in some cases, with the pipeline operator. Trading arrangements tend to be considered in two time scales:

- Short-term needs to fine tune their gas trades near to real time; and
- Long-term needs to have gas delivered in the future.

6.3 The reason that market participants have a short-term need to trade gas is that gas supply and demand can differ from what was expected. Gas supplies may be subject to unexpected outages and demand may vary – for example weather conditions can influence the demand for gas. Currently the variation in demand is more pronounced in Victoria, where there is demand for space heating from residential customers. However, with the increase in demand from LNG exports, volatility may increase in other parts of the East Coast.

6.4 The supply and demand of gas needs to be maintained within a reasonable level of balance in order to ensure gas pressure in pipelines remains within safe operational limits. In many gas markets, trading is continuous to allow market participants to balance their nominations to flow gas onto the system with their nominations to withdraw gas from the system. This need to balance injection and offtakes drives the need for short-term trading.

6.5 As the pipeline operator is ultimately responsible for ensuring that gas pressure in its pipelines is maintained within safe operational limits, it is also necessary for pipeline operators to be able to intervene, by buying additional gas or selling excess gas, when required. Therefore, an important consideration is the role of the pipeline operator, including whether:

- Market participants stop trading prior to the balancing period (akin to a gate-closure in electricity markets) after which it is left to the pipeline operator to balance the system (this is similar to the arrangements in Victoria or on the STTMs[68]) or
- Market participants continuously trade and are primarily responsible for balancing their gas inputs and offtakes, with the role of the pipeline operator being one of residual or last resort balancing.

6.6 One reason that the pipeline operator has to intervene is as a result of market participants being collectively short of gas or collectively having excess gas. As such, in most markets there are settlement arrangements to allocate the costs of managing system imbalances that aim to pass on the costs of system balancing to the market participants that are considered to be responsible for causing the system to be out of balance.

6.7 In the rest of this chapter, we explain the international experience in in the US and European hubs with trading and balancing arrangements. In turn, we

- Briefly set out the types of trading for the future delivery of gas;
- Discuss in more detail the arrangements for short-term gas trading and managing potential imbalances during the gas day; and
- Consider the options for managing imbalances: options for the duration of the balancing period and settling the costs.

Under each section, we explain the main options, the advantages and disadvantages as well as the changes that would be required to current arrangements in the East Coast of Australia.

68 Market participants can trade after gate closure using Market Schedule Variations on the STTMs, but only if they have a counterparty taking an opposite position.

The types of trading for future delivery of gas

6.8 Gas trading for deliveries in the future only takes place at the most liquid gas hubs. The main risk in contracting for future gas deliveries at a hub, is that the gas price alters between the time the transaction is agreed and the delivery date of the gas

6.9 Buyers and sellers hedge against this risk by entering into financial contracts. Financial participants, who do not get involved in the physical delivery of gas, play an important role in offering products to manage these risks. As with all financial markets, trading can take place on either:

- A bilateral or over the counter-basis; and/ or
- Via a centrally cleared exchange.

6.10 Most of the forward trading in gas hubs is done bilaterally or via brokers on an 'over the counter' ('OTC') basis. To manage price risk, the buyer and seller agree a volume and strike price in a contract for difference. If the hub price at the time of delivery is higher than the strike price, the seller pays the buyer the difference so that the buyer is paying the strike price. If the market price is lower than the strike price, the buyer pays the seller the difference so that the seller receives the strike price.

6.11 In exchange based trading, market participants can anonymously trade and the exchange provides clearing services, which removes the counterparty risk. The main difference is that in bilaterally traded markets (known as over the counter- OTC) the counterparties to the trade manage the risk between themselves. However, with the emergence of electronic gas trading platforms in OTC markets, where in some cases the hub provides clearing services, the distinction between OTC and exchange-based trading is blurring[69].

6.12 As financial parties tend not to get involved in the physical delivery of gas, they rely on sufficiently liquid short-term markets in order to be able to trade out their positions before the time of physical delivery[70]. Therefore, we focus on the options for developing liquidity in the short-term traded gas market.

69 IMF, Markets: Exchange or Over the Counter, March 2012.

70 IEA, Developing a Natural Gas Trading Hub in Asia, Obstacles and Opportunities, 2013.

The arrangements for short-term gas trading and managing potential imbalances during the gas day

6.13 Trading in the short term gas market (day-ahead or within day) usually occurs to allow market participants to fine-tune their needs or to respond to unexpected changes in demand. As such, some of the gas being traded has often already been contracted for future delivery on the basis of longer-term contracts; where gas markets are sufficiently liquid these contracts may contain hub prices but in the absence of liquid markets long-term contracts may be priced based on indexes to oil or other products[71].

6.14 Short-term trading can take place on a voluntary or mandatory basis. These can be distinguished as follows:

- Under a mandatory approach to short-term trading, market participants are required to provide offers to sell gas and make bids to purchase gas. This requires centralised trading, whereby a third party matches the bids and offers to establish a price at which a certain level of demand is satisfied over the forthcoming trading period (or periods); and
- Under a voluntary approach, trading can either be centralised: where an exchange matches the submitted bids and offers to establish a market price; or on a bilateral basis: where parties contract to trade gas for near-term delivery.

6.15 In gas markets in the US and the EU, gas trading is voluntary and relies on market participants being incentivised to trade at the hubs. In order to grow liquidity, some hubs in Europe adopted, so-called, gas release programmes, which require certain parties guaranteeing to sell volumes of gas, usually for a certain period of time in order to boost liquidity. However, these measures have had mixed success[72].

6.16 However, the bigger difference between the trading in the US and Europe compared to trading in Victoria and the STTMs is the continuous nature of the trading in the former compared with trading being focused in particular auctions in the latter. This leads to a difference in the role of the pipeline operator in managing imbalances in the markets.

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[71] This is the case in Europe, where liquidity is still developing in many of the hubs. However, in Western Europe we are seeing long-term contracts being negotiated and moving away from oil-indexed pricing to hub prices.

[72] Gas Release and transportation capacity investment as measures to foster competition in gas markets, Section 2, page 4, See: http://www.crninet.com/2011/a1b.pdf

6.17 In Victoria and the STTMs market participants trade day-ahead and in Victoria at certain points during the gas day. After these auctions, trading between market participants largely ceases, akin to gate-closure in electricity markets, at which point the pipeline operator takes over managing the flows on the system. As such, the pipeline operator has the sole responsibility for managing any system imbalances in the run up to and during the balancing period.

6.18 In order to ensure that the pipeline operator balances the pipelines as efficiently as possible, AEMO runs a bidding process to determine a merit order for dispatching balancing services. Imbalances are incorporated into market schedules and the resultant operational schedules define the actions of the system operator. This is essentially an 'operator-led' approach, whereby the pipeline operator manages the imbalances during the balancing period; market participants are incentivised[73] to forecast their inputs and offtakes as accurately as possible and nominate flows where inputs and offtakes balance. However, after trading ceases, market participants are not expected to manage actively any subsequent imbalances.

6.19 This differs to the approach adopted in the EU gas markets, which following the liberalisation process opted for 'market-based balancing'. Under this approach, there is no gate closure, market participants continue to trade throughout the balancing period. Indeed, market participants are incentivised to trade in the short-term gas markets in order to balance their inputs and offtakes during the balancing period. The role of the pipeline operator or the TSO transmission system operator as it is known in Europe is that of 'back-up' or residual system balancer and primary responsibility for balancing sits with market participants. The two roles can be described as:

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73 We consider how market participants can be incentivised to manage their imbalances in the section below '. Managing imbalances: options for the duration of the balancing period and settling the costs'.

- Primary balancing: where each network user is incentivised to balance its own injections into and withdrawals from the gas pipelines by the end of the balancing period; and
- Residual system balancing: in the event that network users do not balance their injections and withdrawals sufficiently the pipeline operator will take balancing actions to maintain the network pressure within safe operational limits.

6.20 Market-based balancing requires market participants to have the means to take an active role in trading to manage their positions. As such, they require:

- Access to information relating to their inputs and offtakes onto the gas transmission system during the balancing period;
- Access to flexible sources of gas; and
- The ability to re-nominate gas flows during the balancing period.

6.21 Hence, the introduction of market-based balancing in Europe went hand-in-hand with requirements on TSOs to provide shippers with information on:

- The overall balance of gas injections and offtakes on the system; and
- The balance of their nominations of gas flows on and off the system.

6.22 As market liquidity develops, gas shippers can use the short-term spot market to manage their imbalances. Market liquidity is likely to be enhanced if access to physical sources of gas used to balance the system is made available to all market participants. To that end, it is also necessary to ensure that shippers have non-discriminatory access to additional sources of gas flexibility, such as line-pack and gas storage. The ability to trade continuously and to re-nominate inputs and offtakes during the balancing period is critical if market participants are to be able to manage their imbalances during the balancing period.

6.23 As the TSO maintains the responsibility of maintaining the system's operations, it is also able to take balancing actions by buying and selling gas. The TSO aims to undertake these actions at least cost, i.e. buys the lowest priced gas available to meet any shortfalls and sells any excess gas for the highest price[74] that market participants are willing to pay.

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[74] The extent to which, in practice, the TSO delivers the least cost in balancing the system has been an issue of some concern to some European regulators. The concern arises from the fact that its monopoly status may mean that it has less incentive to be efficient in balancing than other market participants. Therefore, in GB, the regulator has developed incentive regimes to incentivise the TSO to minimise balancing costs.

6.24 In a fully functioning market- based model, the TSO uses the spot market to buy or sell gas and maintain the system balance. The TSO trading at the hub can also help generate liquidity in short-term trading. Indeed, merging GTS's previously separate balancing platform with the short-term trading platform at TTF is one of the factors in increased liquidity at TTF over the last few years[75].

6.25 However, in the absence of liquid wholesale markets, the TSO may establish its own 'balancing platform' whereby it receives offers for gas as well as bids to buy gas. The TSO is also required to maximise the short-term products that it trades on this platform and manage the bids and offers on a transparent and non-discriminatory basis[76]. The intention is that the balancing platform is an interim step to allow the TSO access to flexible sources of gas until certain liquidity in the spot market in the hub is developed. If a balancing platform remains separate to the trading on the hub, there is a risk that it reduces liquidity on the short-term market.

6.26 The advantages and disadvantages to the two approaches are considered in the following two subsections.

Mandatory auctions with operator-led balancing

6.27 One perceived advantage of requiring buyers and sellers to submit bids and offers into mandatory auctions is that it contributes to liquidity. It ensures that the product is sold to the market and concentrates trading in a particular time period. In markets where buyers and sellers do not enter into pre-existing contracts it is the key mechanism for short-term trading. However, evidence from the AEMC's Stage 1 Report suggests that mandatory trading has not led to significant liquidity in the facilitated markets[77].

6.28 The other advantage of having an operator matching bids and offers is that, to the extent that the bids and offers reflect the underlying fundamentals of supply and demand, it determines an efficient despatch of the sources of supply and ensures that demand is met by the cheapest source of supply. However, this is only true to the extent that the bids into the market reflect the underlying short run marginal costs of production and marginal willingness to pay.

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75 Heather P: Continental Gas Hubs: Are they fit for Purpose, Oxford Institute for Energy Studies, BG 63, June 2012, page 9.

76 See ACER, Framework Guidelines on Gas Balancing in Transmission Systems, FGB-2011-G- 002, 18 October 2011, section 3, and page 10. http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/FG%20Gas%20Balancing_final_public.pdf

77 AEMC, Stage 1 Final Report, East Coast Wholesale Gas Market and Pipeline Framework Review, 23 July 2015, page 27.

6.29 Also, if the pipeline operator has sole responsibility for balancing it is more straightforward for it to manage imbalances. It can take an overview of the system and decide which actions are required to manage any system constraints or imbalances. It avoids the risk of several parties incurring the costs of trading to balance their own individual portfolios, which in some cases may not be necessary, if the overall system is in balance.

6.30 The main disadvantage of the 'operator-led' approach identified in Europe is that, by placing the entire responsibility of balancing on transmission system operators, it, by definition, limits trading by market participants. To the extent that market participants are perceived to be more incentivised than TSOs to trade efficiently (given the profit motivation of market participants) then the operator led approach risks delivering sub-optimal market outcomes. Market based interactions of supply and demand are considered to make it more likely that gas is allocated to those that value it most at any particular time – rather than an approach whereby a centralised monopoly TSO is responsible for managing the interaction of supply and demand [78].

Continuous trading with market-based balancing

6.31 Transferring the primary responsibility for balancing from the system operator to market participants can:

78 In Europe, TSOs were noted to be holding a considerable share of the flexible gas in the market. This gas was effectively being removed from the market when it could otherwise be released to market participants and used for short-term trading in the market. See ACER, Framework Guidelines on Gas Balancing in Transmission Systems, FGB-2011-G- 002, 18 October 2011, section 1.1, and page 4. http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/FG%20Gas%20Balancing_final_public.pdf

- Reduce the balancing actions required by the pipeline operator and the amount of flexibility that the pipeline owner has to procure, which allows for flexibility to be traded by market participants; and
- Increase the incentives on market participants to trade on the short-term market in order to balance their portfolios.

6.32 As such, market-based balancing is often considered to exhibit greater allocative efficiency – particularly in markets where frequent fine-tuning is likely to be required. Market participants are likely to have a stronger incentive to balance efficiently their portfolios than entities that can pass on the costs. Assuming that the charges on market participants for causing imbalances reflect the cost to the operator in buying or selling gas, market participants can judge whether it is more efficient for them to manage an imbalance or leave it to the pipeline operator. Furthermore, it ensures that flexibility is made available to those market participants who value it the most.

6.33 The main disadvantage of 'market-based' balancing is that it can lead to market participants taking balancing actions that are not required if the overall pipeline or network is in balance. A gas network does not necessarily require all parties to balance their inputs and offtakes simultaneously in order for the overall system to be in balance; shippers with equal positive and negative imbalances may balance each other out. Furthermore, an inherent feature of gas pipeline systems is that pressure in the pipeline system can, to some extent, fluctuate – meaning that injections and offtakes do not necessarily always need to balance over shorter timescales[79].

6.34 In networks where more frequent balancing is required, it may be appropriate, as in the Dutch system, to incentivise shippers to trade to assist with the overall system imbalance rather than purely to balance their portfolios. We discuss this in more detail in the section below.

6.35 Therefore, there is a trade-off with 'market-based balancing' between on the one-hand increasing the role of market participants in the market and having several parties involved in the balancing process.

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79 This contrasts to electricity markets, where a second-by-second matching of supply and demand is required to ensure system stability.

6.36 Furthermore, market-based balancing only promotes short-term trading if the necessary pre-requisites are in place; these include access to information on the shippers' individual position as well as the overall system imbalance, access to flexibility and ability to alter nominations. It is also important that the duration of the balancing period is such that it provides shippers enough time to trade and manage their positions before being considered 'out of balance' and therefore cashed out (we discuss this in more detail in the next section).

6.37 The other potential disadvantage with market-based continuous trading is that it is voluntary in nature. There is a risk with voluntary trading that market participants choose not to trade and that liquidity is slow to develop. This is why, in some European hubs, gas release programmes have been introduced for initial periods of time in order to generate trading.

Implementing the options in the East Coast

6.38 Trading occurs on a voluntary continuous basis at Wallumbilla and on a mandatory basis on the STTMs and at Victoria. Given the infrequent need for balancing on the pipelines at Wallumbilla, it may not be appropriate to have mandatory trading prior to a gate-closure after which the pipeline operator balances in this location. If there is a desire to harmonise the trading arrangements throughout the East Coast, then the question may be whether to introduce continuous trading with 'market-based' balancing on the STTMs and in Victoria.

6.39 Introducing continuous trading with market based balancing would require some changes to the arrangements in the STTMs and in Victoria. The main changes would be setting up a market platform for continuous trading of products and amending the balancing rules to place more responsibility on market participants to balance their portfolios. Changes are likely to include:

- Pipeline operators to provide shippers with information during the gas day and balancing periods of a) overall balance of the system and b) their individual inputs and offtakes; and
- Pipeline operators using a transparent gas balancing platform to procure all of the flexible gas required for balancing. The Market Operated Service (MOS) in the STTMs operated by AEMO is similar to a gas balancing platform used under market-based balancing in that it provides a mechanism to price balancing services; however different approaches are used to procure contingency gas from different sources, these could perhaps all be brought under one transparent gas balancing platform; and
- Creating a platform for shippers to trade flexible gas including from line-pack and gas storage; as such non-discriminatory access at fair prices to gas storage and other sources of flexibility will be required.

Managing imbalances: options for the duration of the balancing period and settling the costs.

6.40 Under a market- balancing regime, the costs incurred by market participants for failing to balance their portfolios and the duration of the period over which they are required to balance are key factors in incentivising market participants to trade. In the rest of this section, we outline the options for:

- Setting the duration of the balancing period; and
- Determining the charges for incurring imbalances.

6.41 We explain the advantages and disadvantages of the various options and outline the requirements for change in the East Coast of Australia.

Options for the duration of the balancing period

6.42 The duration of the period over which market participants must balance injections and offtakes onto the network in order to avoid ‘imbalances’ can vary. One factor in determining the appropriate duration of the balancing period is the physical characteristics of the pipelines. Networks or pipelines with:

- Significant volumes of pipeline capacity that are designed to operate with significant fluctuations in the pressure of gas in the pipeline network will be able to maintain greater volumes of gas flowing onto the system than is withdrawn or vice-versa, over longer periods (this flexibility in the pipeline network is known as line-pack); than
- Smaller pipeline capacities with less line-pack, such as the DTS in Victoria, which may require more frequent balancing.

6.43 Hence, when assessing the appropriate duration of the balancing period, one important factor to take into account is the extent to which the physical characteristics of the pipeline network needs to operate in balance. Other trade-offs that need to be considered are the extent to which:

- Shorter duration balancing periods may fragment trading so that liquidity in any one period is reduced;
- Shorter balancing periods create additional costs for market participants (as there is a greater requirement to trade) and can act as a barrier to entry; and
- Longer balancing periods increase the costs of TSO balancing that cannot be targeted on particular participants and, instead, have to be smeared across the generality of shippers.

6.44 At the end of the balancing period any imbalances will be cashed-out and charges passed onto those market participants that are judged (through the settlement process) to have caused the imbalance.

6.45 Based on international experience, the main options for balancing periods range from intra-day to monthly. They include the following:

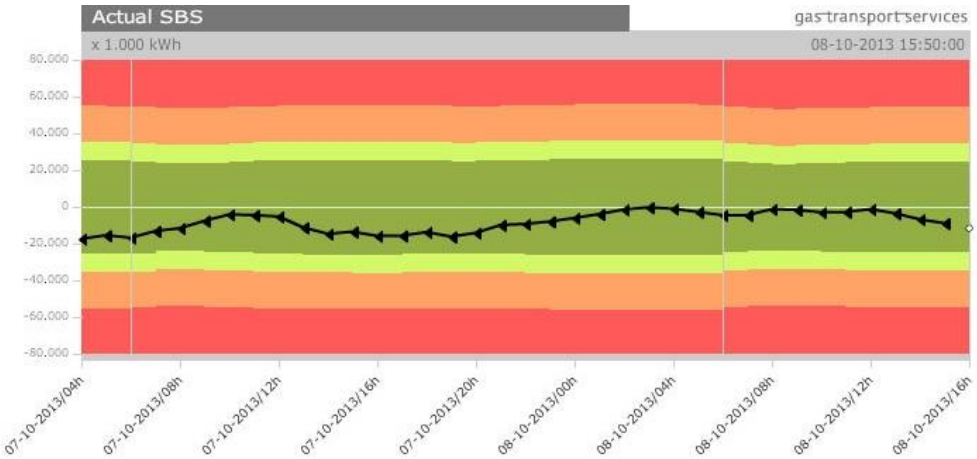
- Hourly balancing, which used to be required on many transmission networks in Europe;
- Intra-day balancing, such as that currently in place on the DTS;
- Daily balancing, which is the favoured approach in the EU vision for liquid gas markets; and
- No specific balancing period, this is used in the Netherlands.

6.46 The Dutch system adopted in 2011[80] is fairly innovative. The key features are:

80 See: http://www.gasunietransportservices.nl/en/transportinformation/balancing-regime

- No specific balancing period; shippers' positions are only relevant if the overall system is out of balance.
- The TSO, GTS, provides each shipper with their balance position (i.e. the difference between its forecast position with the actual allocation in near real-time) as well as the system's balance position, on an ongoing basis during the gas day.
- As shown in Figure 6-1, below, the information signals whether GTS is nearing a requirement to take balancing actions.
- In the event that GTS takes balancing actions, it imposes the costs on the shippers with imbalances at the time the actions are taken;
- The imbalance volume is allocated pro-rata to those shippers with imbalances in the same direction as the system imbalance on the basis of their position at the hour of the imbalance. The price charged is the volume-weighted average price of the gas bought/sold.

Figure 6-1: Example of actual GTS system balancing signal



Sources: GTS.

The imbalance area is divided into zones:

- Dark green: Balancing action is not required;
- Light green: GTS will buy or sell end-of-day product from four hours after imbalance, e.g. an imbalance at 13:00 will see correction from 17:00 to 06:00; and
- Orange/red: GTS will buy or sell a one-hour product, e.g. an imbalance at 13:00 will see correction from 14:00 to 15:00.

Advantages and disadvantages of different balancing periods

6.47 The main advantage of balancing periods of a shorter duration is that it strengthens price signals and ensures that any costs associated with imbalances are directed on those causing the imbalance. By being able to target costs more accurately on market participants, the role of the TSO as residual balancer is likely to be further reduced, which is, in turn, perceived to increase the overall efficiency in the allocation of gas.

6.48 By contrast, with balancing periods of longer durations system imbalances may arise during the period, on account of significant mismatches between flows onto and off the system, that require the TSO to intervene. However, by the end of balancing period the individual participants might have corrected earlier mismatches so as to be measured in overall balance across the period. In these cases, costs will have been incurred by the TSO that cannot be targeted back on individual participants and instead would need to smeared across all market participants

6.49 A disadvantage of balancing periods of shorter duration is that it requires participants to trade more frequently to balance their positions. As trading incurs some cost and there may be uncertainty whether flexible gas products are available to trade at fair prices, this can create a barrier to new market entry, particularly in the absence of a liquid hub. Furthermore, the need for market participants to balance over shorter durations might not actually be necessary in that, for some pipeline systems, there may be sufficient tolerance within the system to allow mismatches of injections and offtakes for certain periods of time.

6.50 The desire to promote market entry led the EU to adopting a requirement for gas shippers to balance their inputs and offtakes by the end of the gas day. This approach was considered to provide the appropriate balance between the efficiency benefits of accurate targeting of the costs of market participant imbalances on the one hand and the benefits in terms of encouraging market entry by not imposing unduly onerous and costly market balancing requirements on participants on the other[81].

6.51 The Dutch system is, in some ways, a response to the trade-off between promoting market trading and encouraging the shippers to contribute to the system imbalances whilst avoiding balancing requirements that are not strictly necessary by targeting costs of the TSO's balancing on those that cause the imbalance if more frequent balancing is required.

6.52 The main advantage is that it is efficient in that it allows shippers to retain certain imbalances if it is not causing an imbalance in the overall system. It also provides shippers with sufficient warning to balance their positions if required and therefore, as it is coupled with a liquid market does not deter new entry.

6.53 The main disadvantage is that it requires operational change for both pipeline operators and shippers: in monitoring the balance in the system as well as shippers individual positions.

81 The EU regulations recognise that it may be more efficient to impose 'within-day obligations', (i.e. obligations on shippers to balance hourly or at specific periods during the gas day, where shippers face charges for imbalances caused at these points during the gas day) where there are likely to be significant costs associated with within-day balancing. . The Dutch system is an example of a regime potentially imposing within-day obligations. See ACER, Framework Guidelines on Gas Balancing in Transmission Systems, FGB-2011-G- 002, 18 October 2011, section 4.2 page 13. http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/FG%20Gas%20Balancing_final_public.pdf

Implementing the options in the East Coast

6.54 Currently the duration of balancing periods varies across the East Coast. In the STTM balancing occurs on a daily basis, whereas at the DWGM it occurs on an intra-day basis. At Wallumbilla pipeline operators generally balance on a daily basis. If there is a desire to determine a balancing period of a common duration, then it will be important to take into account the fact that the East Coast has networks that appear to have differing physical characteristics - with the system in the Victoria region less able to absorb significant mismatches in injections and withdrawals than the network in the north.

6.55 Therefore, it may be difficult to find one balancing period that is appropriate for all pipelines in the East Coast network. As such, we recommend that the AEMC investigates further the merits of introducing the recently introduced Dutch arrangements in Victoria and the STTMs as a means of bridging the need for potentially more frequent balancing in this State compared to other States in the East Coast.

Options for calculating the costs of the balancing actions

6.56 When the pipeline operator takes actions to balance the pipeline, it is essentially buying additional gas because collectively market participants have a shortfall or is selling excess gas because collectively market participants have too much gas. Therefore, in order to incentivise market participants to balance, the costs of buying gas are passed onto those responsible for the imbalance; equally the revenue earned from selling excess gas is also passed onto those who have delivered that gas.

6.57 Under a market-based approach (although this can also be the case with an operator-led approach), the imbalance charges tend to reflect the costs of the operators’ trades that were required to alleviate the system imbalance. The trades take place either on a balancing platform or via short-term trading at the hub. The principle in passing on these costs or revenues to shippers with imbalances is that the shipper pays the operator for gas it buys on its behalf and is paid when the operator sells gas on its behalf. The cost or revenue passed are typically based on either:

- The average cost of gas purchased or the average price paid for gas sold by the system operator in order to balance the system; or
- The marginal cost of gas purchased; i.e. the price paid by the operator to buy additional gas, or the marginal price paid for gas sold by the system operator in order to balance the system.

6.58 Prior to the introduction of the European balancing network code, the imbalance charges in some European countries were not related to the cost of the system operator taking balancing actions, but were either an exogenously set price related to a basket of gas hub prices, such as the TTF, Zeebrugge and NBP[82].

6.59 There is also an option to charge either a single imbalance charge or dual imbalance charges. The difference can be summarised as follows:

[82] This was the case in the Netherlands prior to the introduction of the new balancing arrangements, see 'Competition and Regulation in Network Industries, Volume 14 (2013), No. 1, The Allocative Efficiency of the Dutch Gas Balancing Market by Arthur van Dinther and Machiel Mulder, page 55'.

- A single imbalance charge: the imbalance charge (either based on the average or marginal costs incurred by the system operator) paid by shippers with a shortfall of gas is the same as the price the system operators pays to shippers that over deliver (or under consume) gas;
- Dual imbalance charges: the imbalance charge (either based on the average or marginal costs incurred by the system operator) paid by shippers with a shortfall of gas is not the same as the price the system operator pays shippers who over deliver (or under consume) gas; instead these shippers are paid a lower price (based on either the average cost of buying gas or a percentage of the costs incurred by the system operator). The rationale for two imbalance prices is that shippers will typically face a less favourable price for an imbalance relative to if they had traded out their position with other market participants. In turn, this incentivises ex-ante trading between market participants and therefore is likely to reduce further the requirement for the system operator to intervene to balance the system.

6.60 Measures, known as tolerances, are used in a number of European markets to allow shippers a certain margin of imbalance[83] without incurring any charges for that margin of imbalance. The level of the tolerance needs to be set based on the availability of line-pack in the network. In many European countries, the transmission system operator owns the line-pack in the pipelines. Offering shippers a certain tolerance means that the TSO uses the line-pack to maintain the system balance. The costs incurred from tolerances are spread across all users.

6.61 Besides tolerances, some systems allow shippers to aggregate their imbalances within a balancing group, i.e. a group of shippers, which allows the risk of incurring imbalance charges to be spread across several users.

Advantages and disadvantages of different approaches to calculating imbalance charges

6.62 There is a balance to be struck between incentivising shippers to balance their positions and ensuring that charges do not pose a barrier to new entry; particularly in less liquid markets, where shippers have less access to the means to balance. Hence, in some markets tolerances are permitted as a transitional measure until market liquidity has developed.

83 A tolerance would allow shippers to retain an imbalance of 10 or 20 per cent, it does not dispense with the need for shippers to balance altogether.

6.63 The main advantage of setting imbalance charges based on the marginal price of buying additional gas is that it sends a clear signal to the market participant to balance its portfolio. However, the main disadvantage is that where, markets are less liquid and shippers have less means of balancing their portfolios, this may be considered to deter market entry.

6.64 As such, some countries opt for average prices, which will result in lower imbalance charges than under a marginal price approach. It is for similar reasons to reduce the impact of the imbalance charges that tolerances or pooling arrangements are introduced.

6.65 The main advantage of a single price imbalance charge is its simplicity and is easily calculated by all market participants. It incentivises shippers to 'help the system' i.e. to be long and have excess gas when the system is short of gas. As such, it is more focused on the overall balance of the system rather than shippers balancing their positions.

6.66 A dual cash-out price is used in GB to allow the charges to incentivise all shippers to balance their positions, which promotes ex-ante trading. Given that a shipper with excess gas, when the system is short is paid an average price, i.e. a lower price than the system marginal price for selling gas, this incentivises shippers to sell this gas in the short-term market rather than leaving it to the system operator.

Implementing the arrangements in the East Coast of Australia

6.67 It is not within the scope of this study to conduct an in-depth assessment of the existing gas balancing arrangements in Victoria and the STTMs. Our understanding is that the costs of taking balancing actions are, to a large extent, passed onto those that cause the imbalances.

6.68 However, if introducing market-based balancing, the AEMC may want to review the imbalance charges in more depth and assess the appropriate balance between incentivising market participants to trade and recognising that in the absence of liquid markets market participants have more limited scope to balance their positions.

6.69 Furthermore, there may also be a case for introducing tolerances that reflect the underlying characteristics of the system. If it was desired to have a homogenous duration of balancing periods across East Australia (say of one day), then it may be the case that tolerances in each part of the network might be varied so that, in some parts of the region, there would be greater tolerances afforded to shippers with an imbalance than in other parts.

7. Recommendations and roadmap

7.1 Having considered the options for the types of hubs and trading arrangements, we now present our recommendations for the East Coast of Australia in transitioning towards a liquid wholesale gas market. In this chapter, we summarise our main conclusions and make recommendations on:

- The geographical location and type of hubs for the East Coast; and
- The arrangements for trading and balancing gas at these locations.

7.2 We have sought to stress throughout this report that international evidence demonstrates that liquid wholesale gas markets can develop through either physical hubs, located at particular pipeline interconnection points in the US and at virtual hubs, located across one or more networks as per the European model. Hence, there is no *a priori* bias against one approach or the other – rather there is a need to balance the advantages and disadvantages of each approach and consider which is most suitable in the context of East Australia.

7.3 One other point worth emphasizing is that it should be recognised that the current approach has delivered a sizable network of pipelines across the significant distances of the region. Moreover these investments have occurred in response to price arbitrage opportunities generated by the discovery of new sources of gas and also be the emergence of new sources of demand rather than by regulated or centralised decision making. Any solution to enhance liquidity of gas markets on the East Coast of Australia will need to take into account the need to maintain investment signals.

Recommendation 1: Ensure that all shippers have access to transport capacity on fair and not unduly discriminatory terms

7.4 Regardless of whether the East Coast of Australia opts for physical or virtual hubs, access to transportation capacity to the hubs is a prerequisite. The AEMC's workstream on capacity will need to satisfy itself that market participants can obtain access to transport capacity to convey gas to trading points on not unduly discriminatory terms and at fair prices in order for buyers and sellers to access the hub. Without this transparency there is a risk that shippers may perceive there to be undue differences in prices to access network capacity, which may deter new entry and thus limit the development of liquidity. Therefore, we recommend that the AEMC introduces arrangements for regulatory oversight and publication of prices for gas transportation capacity.

7.5 One way of guaranteeing non-discriminatory access to transport capacity is to include the pipeline within a virtual hub as capacity is allocated to all market participants as demanded. However, the downside of a virtual hub is that the signals for investment in pipeline capacity are only to the entry and exit points of the hub. Within the hub investment decisions are more centralised – typically taken by a system operator, with the regulator overseeing the investment decisions.

7.6 Therefore, in the context of Eastern Australia, the "footprint" of any virtual hubs will need to take into account the benefits of ease of access to pipeline capacity with the need to ensure that locational price signals can still trigger investment in pipeline capacity across the country.

Recommendation 2: The virtual hub in Victoria is modified to include entry-exit arrangements to give locational signals for investment

7.7 Given that a virtual hub already exists in Victoria and demand is likely to remain mainly flat or decline (the demand is mainly residential and industrial demand, although there may be more fluctuation if the demand for LNG export in Queensland filters South), this may suggest that a virtual hub could be retained in Victoria. We would recommend that the existing arrangements are modified to introduce entry-exit capacity allocation. This would allow for signals for investment to emerge at entry points into or exit points (where there are multiple users) to signal investment.

7.8 It will be important to consider how to transition the existing capacity rights for Annual Maximum Daily Quantities (AMDQs), which give shippers holding these rights priority in the event of congestion, to capacity rights under an entry-exit system. One solution would be to convert these rights into equivalent entry-exit capacity rights; the challenge will be setting the terms of the conversion.

7.9 Initially, the Sydney and Adelaide STTMs would sit outside the virtual hub in Victoria; these may continue to be separate balancing hubs or overtime merge into one or other of the hubs. For example, Sydney may merge with Victoria or if connection was built, with Wallumbilla.

Recommendation 3: A virtual hub at Wallumbilla that, depending on cost-benefit analysis, can be extended over time

7.10 Demand in Queensland is expected to grow substantially with an increasing fluctuation in the direction of flows between the North and South of the region. Therefore, there is a possibility that transport capacity will become scarce in the future. As such, it is important that the future arrangements provide for both booked but unused capacity to be released to market participants on fair and not unduly discriminatory basis while the signals for future investment are maintained.

7.11 Given the need for location specific investment signals, this could favour physical hubs or a small virtual hub in the Northern part of the region. A small virtual hub encompassing only a few pipelines and a physical hub are very similar in terms of footprint and impact on investment signals; the main difference is how the services within the hub are offered.

7.12 Given the small size of the East Coast market and the need to facilitate new entry, there may be a benefit in pooling the liquidity by extending the scope into a virtual hub. A first step towards this could be a virtual hub at Wallumbilla, which then subsequently includes other pipelines, subject to an assessment of the benefits in terms of increased liquidity outweighing the costs (of congestion and regulated investment decisions within the hub).

7.13 The RBP, which connects Wallumbilla to Brisbane has a number of exit points, which are used by different market participants, and connects with the Brisbane STTM. We also understand that it is a regulated pipeline, although only one service is regulated so more regulation would be required, and on which demand is forecast to be relatively flat. As such there may well be benefits of including this pipeline within a Wallumbilla virtual hub. By encompassing this pipeline and the STTM, a Northern virtual hub may provide greater potential for trading and liquidity to develop.

7.14 It is also relevant to consider whether it would be beneficial to widen further the virtual hub in order to include the SWQP pipeline, which connects Wallumbilla to Moomba. Our view is that, given the distances involved and, we understand, the potential need for future investment in the SWQP pipeline route between Wallumbilla and Moomba, then it may be more appropriate to keep this pipeline outside of the virtual hub. Given the strategic importance of this route, it will be particularly important that the AEMC's capacity workstream is satisfied that (as per our first recommendation above) there is fair and not unduly discriminatory access to this pipeline.

7.15 Overtime, other pipelines may merge into the hubs. For example, the pipelines to the LNG terminals at Gladstone are currently exempt from third-party access but may be encompassed into a Northern virtual hub at a later date.

7.16 We understand that a physical hub at Moomba is currently being considered. This seems to us sensible as it will allow a price to emerge at Moomba and may trigger further investment if persistent price differentials between Moomba and other part of the country signal such a need. Indeed, we understand that pipeline investment from the Northern Territory to Moomba or Mount Isa, which connects to Moomba is being considered. As such, there is a potential for this point to be a useful price point as the East Coast interconnects to other parts of Australia.

7.17 In conclusion, we recommend that the AEMC establishes a small virtual hub at Wallumbilla, which is extended to include RBP, and potentially other pipelines, subject to the benefits of greater trading outweigh the costs.

Recommendation 4: Harmonised trading arrangements across all hubs in the East Coast

7.18 Given the potential for increased flows between the North and the South of the region, harmonising the trading arrangements at the different hubs would be beneficial.

7.19 We understand that there is potentially less need for frequent balancing on the larger pipelines at Wallumbilla and Moomba. In these cases introducing an operator-led model where the pipeline operator balances following a gate-closure may lead to inefficiencies. Therefore, this would suggest that it would be for Victoria and the STTMs to migrate to a model of bilateral continuous trading with market-led balancing.

7.20 There may be concerns that voluntary trading would lead to a reduction in liquidity as shippers would now have a choice whether to trade. The concerns that voluntary trading leads to low liquidity could, in part, be mitigated by the fact that market-led balancing may provide some impetus on market participants to trade. However, if there are concerns about initial lack of liquidity, AEMC or the relevant authority could further investigate whether gas release programmes for a specific transitional period could promote liquidity.

7.21 Given that the duration of the balancing period is partly driven by the physical characteristics of the pipelines and more frequent balancing is required in Victoria and, perhaps the STTMs than elsewhere, determining a common balancing period is difficult. As such, we recommend that the AEMC investigates introducing in Victoria and the STTMs an unspecified balancing period, similar to the Dutch arrangements, as part of the transition towards market-based balancing.

7.22 Finally, we recommend that the balancing arrangements are reviewed in greater detail. It appears that arrangements are already in place, which are consistent with market-based balancing, including a balancing platform to procure line-pack are already in place and imbalance charges based on the cost of buying additional gas. However, it will be important to ensure that all gas procured by the pipeline operator is procured on the gas balancing platform and that the charges incentivise the appropriate balance between incentivising trading and recognising the low levels of liquidity in the short-term gas markets.