REVIEW

Australian Energy Market Commission

DISCUSSION PAPER

Review of the Victorian Declared Wholesale Gas Market

10 September 2015

Reference: GPR0002
Discussion Paper

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

Reference: GPR0002

Citation

AEMC 2015, Review of the Victorian Declared Wholesale Gas Market, Discussion Paper, 10 September 2015, Sydney

About the AEMC

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

Foreword

The Victorian declared wholesale gas market (DWGM) is the longest-standing wholesale gas market in Australia. Preceding all three short term trading market hubs and the recently implemented gas supply hub model, the DWGM encompasses the entire declared transmission system and is the only virtual hub on the east coast.

The DWGM was established in 1999 by the Victorian government with the objective of supporting retail competition and encouraging the diversity of supply and upstream competition. Today, the DWGM is generally regarded by participants as having met these objectives, providing an effective and competitive gas balancing service and facilitating trading of gas in Victoria based on short-term prices.

Retail competition in the gas market in Victoria is considered to be effective with low market concentration and high customer activity. Two new retailers entered the market in 2015, bringing the total number to ten. Data available on switching also suggests customers are actively shopping around between the retailers available.[1]

Notwithstanding the relative success of the DWGM to date, the east coast gas industry is currently facing a structural change like no other witnessed as a result of the liquefied natural gas (LNG) export industry. It is expected that large volumes of gas from Queensland and South Australia will be dedicated to these operations and end users in these states will have to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect, the Eastern Gas Pipeline or the SEA Gas Pipeline. Equally, market participants may seek to transport large volumes of gas into Victoria for sale in the DWGM in instances where the LNG export plants are unable to absorb supply due to, for example, an LNG train being taken offline.

The east coast gas industry is therefore transitioning into unchartered territory. As noted by Ministers at their July 2015 meeting, "the gas market is entering a new era of dynamism, and the imperative was to get the fundamentals right to prepare market participants for new ways of price discovery, trading, investment and risk management".[2]

It is therefore paramount that the Victorian gas market arrangements are sufficiently flexible to a range of potential scenarios and that they allow participants to actively manage the risks they face. Additionally, investment needs to occur in a timely and efficient manner and the interaction between the Victorian market arrangements and adjacent markets should occur as seamlessly as possible.

In this respect, this discussion paper has been developed to progress the debate on gas market development and to provide stakeholders with the opportunity to provide more focussed feedback leading into the Draft Report for the Declared Wholesale Gas Market Review, which the Commission will be releasing in December 2015. It provides stakeholders with the opportunity to respond to five high-level packages for reform

1 AEMC, *2015 Retail Competition Review*, 30 June 2015, p. 150.

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

which have been developed as a possible means of addressing one or more of the gaps identified in the existing market design and regulatory framework in Victoria. It is important to note that these packages do not represent a preferred approach, but have instead been developed to facilitate discussion.

We appreciate the time and resources dedicated by stakeholders to the review so far, particularly over such condensed timeframes, and thank stakeholders for engaging with the Commission throughout the review process.

John Pierce

Chairman

Executive summary

This paper has been developed to progress the debate on gas market development in Victoria and is intended to further the discussion developed to date as part of the DWGM Review and the coincident East Coast Wholesale Gas Markets and Pipeline Frameworks Review (the East Coast Review).

The purpose of the DWGM Review is to consider whether the current Victorian arrangements provide appropriate signals and incentives for investment in pipeline capacity, allow market participants to effectively manage price and volume risk and facilitate the efficient trade of gas to and from adjacent markets. More broadly, the Review is to consider whether, and to what extent, the DWGM continues to effectively promote competition in upstream and downstream markets, in the long-term interest of consumers.

This report presents an appraisal of the current DWGM arrangements in these areas. In particular, this report does the following:

- Outlines how market participants can manage price and volume risk currently, and discusses the underlying issues that are preventing greater use of derivatives and other risk management tools.
- Considers the current mechanisms relied on by various market participants to signal opportunities for investment in pipeline capacity, as well as opportunities to improve these signals to facilitate timely and efficient investment.
- Outlines the perceived issues with the framework for regulated investment in the Declared Transmission System (DTS). Specifically, it considers whether the current regulatory framework provides the right incentives and opportunities for the DTS service provider (APA GasNet) to make efficient and timely investments.
- Considers the opportunities for market-led investment in the DTS and explores the reasons why the current DWGM design and market carriage model are not conducive to such investment. It also discusses the interaction between regulated and market-led investment.
- Outlines the transportation arrangements and market actions required for market participants to be able to move gas to adjacent markets. It also outlines perceived barriers to exporting from Victoria and the extent to which recent developments have addressed some of these issues.

Five high level packages for reform have also been developed as a way of seeking targeted feedback from stakeholders on the future development of the Victorian gas market. Each package includes one or more policy measures which could address the issues identified in the appraisals. While they have been prepared having regard to the terms of reference for the DWGM Review and the Council of Australian Governments' (COAG) Energy Council Vision for Australia's future gas market, they have not yet been tested against the assessment framework developed in the Stage 1 Report for the East Coast Review.[3] As such, they do not represent a preferred approach.

The five high-level packages for reform are illustrated in the figure below.

Market improvements	Market development		Market reform	
Package A Targeted measures	Package B Transmission rights	Package C Capacity rights	Package D Entry/Exit model	Package E Hub & Spoke model
Targeted transmission rights	Simplified pricing mechanism	Zone-based pricing and capacity rights	Entry/Exit model	GSHs at Longford and Iona and balancing in Melbourne
Trading of AMDQ rights	Transmission rights			
Clearer AMDQ allocation process				
Review planning standard				

Each package assembled is consistent with one of the three concepts established as part of the AEMC Wholesale Gas Markets Discussion Paper, published on 6 August 2015 as part of the wider East Coast Review.[4] In assessing any, or all, of these packages further, we will explicitly consider the feasibility of replicating these designs in a 'northern' market, consistent with the concepts set out in this earlier discussion paper. The Commission considers that this would be consistent with the COAG Energy Council's Vision and should, by reducing transaction costs, encourage greater trading and participation in east coast gas markets.

The Commission welcomes feedback on these packages of possible reforms. In particular, the Commission is interested to hear whether (and the extent to which) these packages:

- are likely to address the issues identified in the appraisal;
- continue to safeguard the security of gas supplies to Victorian customers;
- are proportionate to the problem(s) being addressed; and
- promote, or detract from, the National Gas Objective.

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

Submissions on this discussion paper are invited by 8 October 2015.

3 The assessment framework is included in Appendix E of this discussion paper.

4 The AEMC Wholesale Gas Markets Discussion Paper is available on the AEMC's website: www.aemc.goc.au

Contents

1 Introduction

1.1 Context for the review

Australian gas markets are experiencing a rapid transition as conventional gas reserves decline, unconventional gas resources become increasingly important and the influence of international price trends increase. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering a shift in supply and demand. These factors have resulted in a renewed focus on market development and gas supply chain efficiency.

The Gas Market Scoping Study 2013 commissioned by the Australian Energy Market Commission (AEMC) highlighted the fragmented nature of gas market development and identified areas for improvement in the current regulatory and market arrangements. It also highlighted the need for a strategic review to consider the direction that the eastern Australian gas market should take over the next ten to 15 years.[5] Further, a critical question raised by the 2013 Victorian Gas Market Taskforce was whether the significant structural changes underway in the eastern gas market require reforms to enhance the liquidity, transparency and flexibility of the current arrangements.[6]

1.2 The Review of the Victorian Declared Wholesale Gas Market

In light of the significant structural changes underway across the east coast gas markets, the Victorian Government, with the agreement of the Council of Australian Governments (COAG) Energy Council, has asked the AEMC to undertake a review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian Declared Wholesale Gas Market (DWGM).[7]

As outlined in the terms of reference for the review received from the Victorian Government on 4 March 2015, the purpose of the review is to consider whether the DWGM provides appropriate signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates efficient trade of gas to and from adjacent markets. More broadly, the review will consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long term interests of consumers.

The terms of reference are available in full on the AEMC's website. In summary, the Commission is required to consider the following when undertaking its review of the Victorian DWGM:

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

6 Victorian Gas Market Taskforce, *Gas market taskforce: final report and recommendations*, 2013.

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

- Effective risk management: the ability of market participants to manage price and volume risk in the DWGM, and options to increase the effectiveness of risk management activities.

- Signals and incentives for efficient investment in and use of pipeline capacity: whether market signals and regulatory incentives are providing for efficient use of, and efficient and timely investment in, pipeline capacity on the DTS which underpins the DWGM.

- Trading between the DWGM and interconnected pipelines: whether producers and shippers can effectively operate across the different gas trading hubs on the east coast without incurring substantial trading costs.

- Promoting competition in upstream and downstream markets: whether the DWGM arrangements continue to facilitate market entry and promote competition in upstream and downstream markets and how this could be improved.

In providing the terms of reference for the Victorian DWGM Review, the Victorian Government noted that there will be links between the recommendations and findings of the east coast and DWGM reviews. Given these linkages, the AEMC and Victorian Government agreed to combine the initial phase of the Victorian DWGM Review with the East Coast Review. The scope of the East Coast Review is outlined in the next section.

1.3 The East Coast Gas Market and Pipeline Frameworks Review

The AEMC has also been asked by the COAG Energy Council to review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia ("the East Coast Review"). The East Coast Review is considering the roles and objectives of the existing markets on the east coast in light of changing market dynamics, and aims to set out a road map for their continued development.

The terms of reference for the East Coast Review, received on 20 February 2015, is also provided on the AEMC's website. Broadly, it requires the Commission to consider the following when undertaking its review of the east coast wholesale gas market and pipeline frameworks:

- The appropriate structure, type and number of facilitated markets on the east coast, including options to enhance transparency and price discovery, and reduce barriers to entry.

- Opportunities to improve effective risk management, including through liquid and competitive wholesale spot and forward markets which provide tools to price and hedge risk.

- Changes to strengthen signals and incentives for efficient access to, use of, and investment in, pipeline capacity.

The terms of reference for the East Coast Review also ask the AEMC to develop specific actions that can be implemented to strengthen the structure and competitiveness of the east coast gas market, and make recommendations for immediate implementation, where possible.

1.4 Review process

The east coast and DWGM reviews have been structured over two phases. Stage 1 of the review was completed on 23 July 2015 with the Stage 1 Final Report presented at the Energy Council's July 2015 meeting.[8] The Final Report provides an overview of how Australia's gas markets function and outlines areas where reforms may be required to accommodate the changing dynamics created by LNG exports and coal seam gas production. The report recommends four immediate actions for consideration by the Energy Council to enhance the transparency and efficiency of the market.

With Stage 2 now underway, the Victorian DWGM Review has split from the East Coast Review and will continue throughout 2015 as a stand-alone review. For both reviews, Stage 2 will develop more options to promote long-term gas market development and enable the rules governing the markets and pipelines to be fit for purpose in the new gas environment. The AEMC intends to provide the Stage 2 draft report for the East Coast Review, and the draft report for the Victorian DWGM Review, to the Energy Council (and the Victorian Government for the Victorian DWGM Review) ahead of its December 2015 meeting. The final reports for both reviews will then follow receipt of a response from the Energy Council on the draft recommendations.

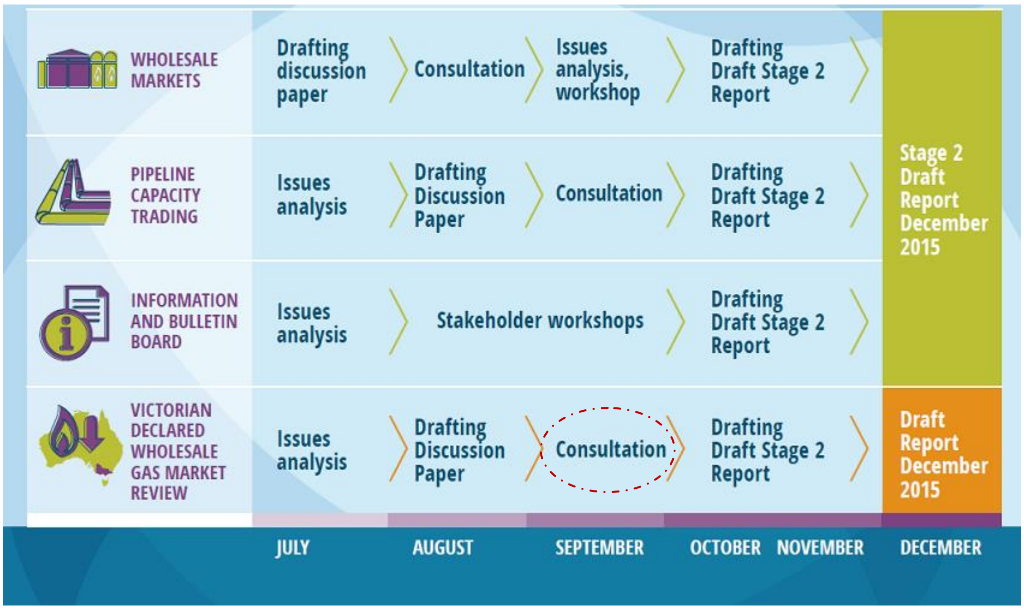
As required by the terms of reference for the East Coast Review, the AEMC has established an Advisory Group that will operate across both reviews. The Advisory Group provides strategic advice and expertise to the Commission over the course of the review. The group meets periodically and is chaired by John Pierce, AEMC Chair.

1.5 Next steps in the development of our advice

As outlined in Chapter 3 of the Stage 1 Final Report, there are four workstreams being progressed by the Commission as part of Stage 2. These are illustrated in Figure 1.1. This discussion paper relates to the Victorian DWGM Review.

8 This follows the Stage 1 draft report, released on 7 May 2015. Both the draft and final reports are available on the AEMC's website.

Figure 1.1 Stage 2 Workstreams



Source: AEMC.

Feedback from stakeholders through the consultation process, as well as input from the work undertaken in the other three workstreams over the remainder of 2015, will inform the Commission's recommendations in the draft report for the Victorian DWGM Review. The Commission will also be working closely with the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER) throughout all elements of this review of the Victorian DWGM to draw on their operational and regulatory expertise as we develop our advice.

1.6 Responding to this paper

The Commission welcomes submissions on any of the issues and packages raised in the discussion paper.

The closing date for submissions is **Thursday, 8 October 2015**.

Submissions should quote project number "GPR0002" and may be lodged online at www.aemc.gov.au or by mail to: Australian Energy Market Commission PO Box A2449 Sydney South NSW 1235.

1.7 Structure of this paper

The remainder of this discussion paper is structured as follows:

- Chapter 2 provides an overview of the Victorian DWGM today, including an assessment of whether it has achieved the original objectives. It also highlights the challenges facing the eastern Australian gas market.

- Chapter 3 outlines how market participants can manage price and volume risk in the DWGM. It also discusses underlying issues that are preventing greater use of derivatives and other risk management tools in the DWGM, consistent with the terms of reference.
- Chapter 4 considers current mechanisms in the DWGM relied on by various market participants to signal opportunities for investment in pipelines. It also considers opportunities to improve these signals to facilitate timely and efficient investment.
- Chapter 5 outlines the perceived issues with the framework for regulated investment in the DTS. Specifically, it considers whether the current regulatory framework provides the right incentives and opportunities for the DTS service provider (APA GasNet) to make efficient and timely investments.
- Chapter 6 considers the opportunities for market-led investment in the DTS and explores the reasons why the current DWGM design and market carriage model may not be conducive to private investment. It also discusses the interaction between regulated and private investment.
- Chapter 7 outlines the transportation arrangements and market actions required for market participants to be able to move gas from Victoria to interconnected markets. It also outlines perceived barriers to exporting from Victoria and the extent to which recent developments have addressed some of these issues.
- Chapter 8 identifies and outlines possible policy measures which could address the issues identified in the appraisals. It organises the individual policy measures into a series of policy packages involving varying degrees of reform. A high level assessment of each policy package is also provided.

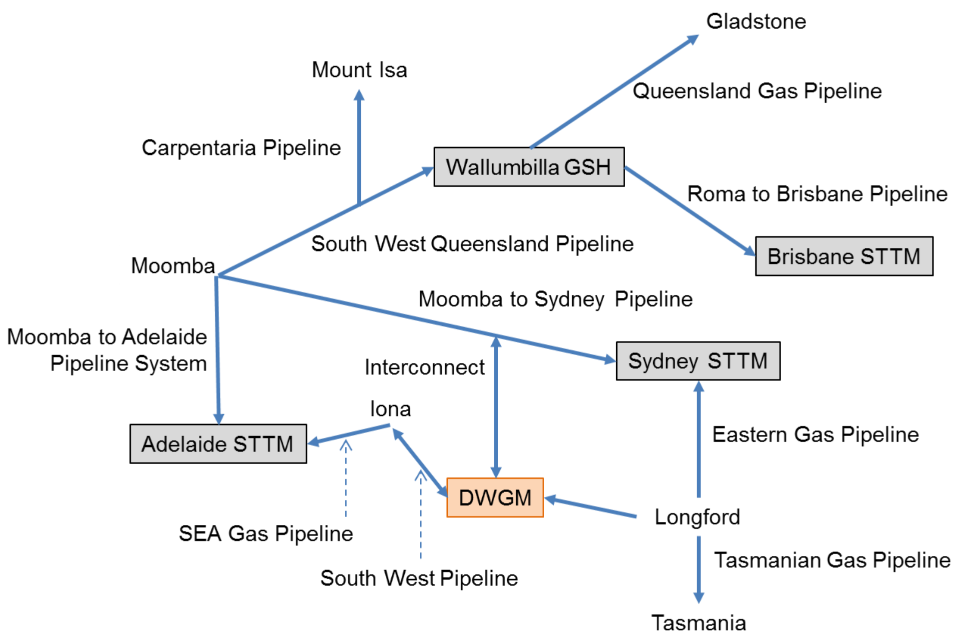
The discussion paper also contains a number of appendices, as follows:

- Appendix A: Glossary.
- Appendix B: Arrangements to facilitate exports from Victoria.
- Appendix C: Authorised Maximum Daily Quantity.
- Appendix D: Overview of DWGM rule change requests.
- Appendix E: Assessment framework.

2 Current state of the DWGM and emerging challenges

The Victorian declared wholesale gas market is the longest-standing wholesale gas market in Australia. Preceding all three short term trading market (STTM) hubs and the recently implemented gas supply hub (GSH) model, the DWGM encompasses the entire declared transmission system (DTS) and is the one virtual hub on the east coast. The location of the DWGM relative to the other facilitated markets and transmission pipelines on the east coast is illustrated in the figure below.

Figure 2.1 Location of the DWGM on the east coast



Source: AEMC.

The DWGM was established in March 1999 by the Victorian Government as part of its privatisation process. As part of this process, the following occurred:[9]

- the DWGM was developed to enable participants to trade imbalances;[10]
- the ownership and operational functions of the pipeline transmission system were separated and a decision was made to operate the DTS on a market carriage basis; and
- an independent system operator, VENCorp (one component of AEMO), was given responsibility for operating both the DWGM and the DTS, balancing gas

9 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 53.

10 The intention of imbalance trading is to allow parties to balance gas deliveries (that is, gas purchased from producers) with gas consumption (that is, gas consumed by end-users).

supply and demand and transportation capacity through a centrally co-ordinated scheduling process.[11]

This chapter outlines the history and original policy objectives of the DWGM and market carriage arrangements applying to the DTS, as well as the various refinements made since inception. This chapter also outlines the function of the DWGM today and the emerging challenges going forward to provide context for this review.

2.1 Original objectives of the DWGM

The rationale for adopting the DWGM and the market carriage model in Victoria can be summarised as follows:[12]

1. It reflects the physical characteristics exhibited by the DTS:
   - The DTS exhibits meshed network characteristics.
   - The amount of gas that can be stored in the DTS is also quite small and cannot be relied upon to manage significant deviations between demand and contracted supply.[13]
   - The physical characteristics of the DTS, coupled with the fact that the demand for gas in Victoria exhibits a significant degree of seasonal and daily variability (due to the high residential load), mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained.
   - The physical characteristics exhibited by the DTS also mean that it can be very difficult to determine how to define firm capacity rights to shippers.[14]
2. It was expected to support full retail contestability – The market carriage model and the DWGM were seen as a way of encouraging new entry by retailers because they would not need to enter into long term gas transportation agreements and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.

---

11 VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, p. 22.

12 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 11; and VENCorp, *Application for Authorisation of Market and System Operations Rules*, 17 May 2002, pp. 21-24.

13 A 2002 report by VENCorp states that total linepack in the DTS varies between about 450 TJ and 600 TJ over each day as the system demand is satisfied and that on peak days over 1,100 TJ is shipped through the network, or approximately twice the entire linepack in the system. By way of comparison, the then peak demand on the Moomba pipeline was stated to be approximately 25 per cent of the daily transported volume. See: VENCorp, Application for Authorisation of Market and System Operations Rules, 17 May 2002, p. 23.

14 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 11.

3. It was designed to encourage diversity of supply and upstream competition – The transparency of pricing provided by the DWGM and the operation of the market carriage model were expected to encourage the development of new sources of supply and upstream competition.

Between 1999 and 2007, the DWGM market price was determined on a daily ex-post basis. However, on 1 February 2007, the market moved to ex ante intra-day trading following a review in 2003-04 by VENCorp. The 2003–04 review, also known as the Pricing and Balancing Review, aimed to:[15]

- provide more efficient and transparent pricing signals;
- improve market interaction and response to pricing signals;
- provide adequate incentives and flexibility for demand-side response; and
- facilitate investment in pipeline infrastructure.

VENCorp recommended a three stage approach to reforming the DWGM, namely:[16]

- stage 1 – introduction of ex ante intra-day pricing;
- stage 2 - introduction of transmission rights; and
- stage 3 - development of a number of hubs and introduction of capacity rights.

To date, the only changes that have been made to the DWGM are those that were recommended to occur in stage 1. VENCorp found that the existing ex-post design did not provide participants with either the ability or the incentive (that is, the price signal) to respond to changing market conditions during the day, which was a driver behind switching to a system of ex ante pricing in 2007.[17]

While the original market design has been developed on an incremental basis since market-start, the underlying fundamental structure remains unchanged – a set of arrangements designed to offer a balancing trading service, a spot commodity trading service and to allocate capacity on the DTS.

2.2 The DWGM today

When the DWGM was implemented, the STTM and GSH had yet to be established and the large-scale Queensland LNG developments had not been contemplated publicly. The Victorian system operated in isolation and was not interconnected to the rest of the east coast pipeline transmission system.

15 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, July 2013, pp. 11-12.

16 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 55.

17 VENCorp, *Victorian Gas Market Pricing and Balancing Review – Recommendations to Government*, 30 June 2004.

Box 2.1 How the east coast gas market works today

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

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

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

- short term trading markets (STTMs) in Adelaide, Brisbane and Sydney (broadly physical hubs);
- the declared wholesale gas market (DWGM) in Victoria (a virtual hub covering the Victorian declared transmission system (DTS)); and
- the gas supply hub (GSH) at Wallumbilla (physical hub).

The DWGM and STTM were primarily introduced to support retail competition and as a mechanism to resolve daily gas imbalances in a transparent and competitive way, while the GSH was implemented to facilitate trading close to production centres. Trading of gas on the facilitated markets is generally low and split across these five locations. A sixth gas market could be operational in 2016, with another GSH to be potentially implemented at Moomba.[18]

The STTMs and DWGM are gross pool designs where all gas shipped to and withdrawn from the hubs must be transacted through the markets. The GSH on the other hand is a voluntary market that participants may opt to use to buy and sell gas at one of the three locations in the Wallumbilla hub.

Prices in the STTM and DWGM are determined by stacking and matching offers with bids in price order once per day and five times per day, respectively. GSH prices are established through matching buy and sell orders, similar to a stock market.

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

18 AEMO, *Moomba Trading Location*, High Level Design Report, May 2015.

further participation has likely been limited for two reasons:

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

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

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

Today, the DWGM is generally regarded by participants as providing an effective and competitive gas balancing service and facilitating trading of gas in Victoria based on short-term prices. The DWGM and associated market carriage arrangements in Victoria are widely regarded as being more conducive to market entry and promoting retail competition than the STTM and contract carriage model.[19]

Specifically, retail competition in the gas market in Victoria is considered to be effective with low market concentration and high customer activity. Two new retail brands entered the market in 2015, bringing the total number of retail brands to ten. Data available on switching also suggests customers are actively shopping around between the retailers available.[20]

However, as part of the recently completed Retail Competition Review, one respondent survey noted that entry and expansion conditions in the DWGM could deteriorate if conditions in the wholesale gas market continue to tighten and wholesale gas prices continue to rise. Other respondents noted that greater regulatory and policy risk could also affect entry into this market.[21] These factors are discussed in the section below.

19 K Lowe Consulting, *AEMC 2014 Retail Competition Review: Retailer Interviews*, Report for the AEMC, June 2014, pp. 18, 22, 25, & 30.

20 AEMC, *2015 Retail Competition Review*, 30 June 2015, p. 150.

21 AEMC, *2015 Retail Competition Review*, 30 June 2015, p. 178.

Further, while the adoption of the Pricing and Balancing Review stage 1 recommendations (that is, moving to ex-ante intra-day pricing) have improved the price signals and incentives provided in the DWGM, there appear to be a number of weakenesses in the market signals and incentives provided in the market currently. These observations are summarised in the section below and examined in detail in chapters 4 to 6.

2.3 Context for this review

While the DWGM and associated market carriage arrangements are generally considered to have been providing an efficient gas balancing service and facilitating trading of gas in Victoria historically, the eastern Australian gas market is experiencing a period of significant growth and change.

In response to the establishment of an LNG export industry, the east coast gas market is experiencing structural changes to demand and supply dynamics. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect, the Eastern Gas Pipeline or the SEA Gas Pipeline. Equally, market participants may seek to transport large volumes of gas into Victoria for sale in the DWGM where the LNG export plants are unable to absorb supply due to, for example, an LNG train being taken offline.

With the first LNG cargoes exported from Gladstone in January 2015, the domestic market is already feeling the effects of greater competition for gas. These developments are expected to put upward pressure on gas prices and have resulted in a renewed focus on the efficiency of the gas supply chain. In Victoria, wholesale prices in the first two quarters of 2015 have increased five and 17 per cent, respectively.[22]

Given the uncertainty around market outcomes for participants, gas market arrangements need to be flexible enough to support a range of potential scenarios out past 2020. In particular, these arrangements need to provide for:

- end-users, such as industrial and commercial customers, as well as retailers, to have the ability to effectively manage risk in the DWGM; and
- investments to expand the DTS to occur in a timely and efficient manner, thereby minimising risks of inefficient congestion on the DTS.

It is also important that the interaction between the DWGM and interconnected gas markets is as seamless as possible. This will reduce transaction costs and unnecessary volatility for market participants, minimising costs for end users of natural gas.

In this context, it is critical that the Victorian DWGM is examined to better understand whether the significant structural changes underway in the eastern gas market require

22 AER Wholesale Statistics, available at: http://www.aer.gov.au/Industry-information/industry-statistics/wholesale

reforms to the DWGM to enhance the liquidity, transparency and flexibility of the current arrangements.

3 Risk Management

Efficient markets tend to allow participants to manage the physical operational risks of delivering gas safely, as well as the financial risks associated with price fluctuations. To support effective risk management, market participants need to have access to a meaningful reference price reflective of underlying supply and demand conditions. A meaningful price will aid commercial decision making and the development of financial products.

This section outlines how market participants can manage price and volume risk in the DWGM currently and presents an appraisal of these arrangements. In particular, this section discusses the underlying issues that are preventing greater use of derivatives and other risk management tools in the DWGM, consistent with the terms of reference.

This section assumes a working knowledge of the DWGM and does not re-present existing material on how the market operates.[23]

3.1 Ability of market participants to manage ex-ante price risk

Market participants face price risk in markets through exposure to a price they have to pay for a given quantity of a good or service. In the DWGM, this risk is embodied in 'imbalance payments', which are participant payments to or from the market depending on whether the participant is a net withdrawer or injector. These payments are calculated as the quantity of net withdrawals or injections (which can be zero if a party expects to inject and withdraw the same amount) multiplied by the ex-ante price.

Participants can currently manage the risk of exposure to imbalance payments by contracting for gas supplies to meet their gas usage requirements. Specifically, market participants with contracted gas supplies can adopt bidding strategies to allow them to enter into equal and opposite positions in the DWGM (that is, be on both the buy- and sell-side of the market) and render themselves immune to the market price (to the extent they remain in balance).

For example:

- a market participant may choose to structure its bids and offers so as to deliberately accept a positive imbalance position and buy gas from the market when the market clears at a low price (lower than their contracted supply); or
- alternatively, a market participant may choose to adopt a strategy that seeks to minimise its scheduled imbalances and minimise its exposure to the market price at any level (for example, offering at $0/GJ and bidding at $800/GJ).

23 Appendix F of the Stage 1 East Coast Review provides a detailed overview of the DWGM design and operation, which can be found at: http://www.aemc.gov.au/Markets-Reviews-Advice/East-Coast-Wholesale-Gas-Market-and-Pipeline-Frame

As a simple practical example, market participant A could offer a certain amount of gas it has contracted for into the DWGM at $0/GJ (price floor) and bid to withdraw that gas at $800/GJ (the market price cap). This essentially guarantees their gas injections and withdrawals will be scheduled (that is, there will be no 'imbalance') and makes them immune to the resultant ex-ante market price.

However, there are parties and instances where this price risk is currently unmanageable using bidding strategies in the DWGM, namely:

- participants that cannot secure contracts for delivery at the DWGM (for example, small/new retailers that cannot contract for gas and only appear on one side of the market, for example, the buy-side) – these parties are fully exposed to price risk; and
- participants that do have contracts for delivery but anticipate that they will withdraw more than their contract(s) allow them to inject – these parties are partially exposed to price risk (that is, for gas withdrawals they are not contracted for).

In a liquid wholesale gas market, participants should be able to hedge their position against price risk by using financial products.

In 2009, the Australian Stock Exchange (ASX) introduced a number of derivative products that are linked to the price payable at the beginning of the day in the DWGM.[24] However, we understand that these products have not been traded since June 2013,[25] which is likely to be because the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers, and minimising their spot price exposure through their bidding behaviour. In addition, these ASX products only provide a hedge against the 6.00am ex ante price[26] (as determined with reference to the beginning of the day prices) and not against any uplift charges (discussed in the section below).[27]

A fundamental prerequisite to hedging is that parties can take equal but opposite positions in the spot and futures market for a particular quantity of a commodity.[28] The fact that there are separate uplift payments (outlined in the section below) means that this prerequisite does not hold in the DWGM as participants cannot take truly opposite positions to any uplift payments and so not all of the trading risk is captured

24 These products are currently: (1) Victorian wholesale gas futures (in units of 100 GJ of natural gas per day over the period of a calendar quarter); (2) Victorian wholesale gas strip futures (units are four Victorian wholesale gas futures contracts); and (3) Strip options over Victorian wholesale gas futures (an option over four predetermined Victorian wholesale gas futures contracts).

25 Data provided by ASX Energy.

26 Ex ante prices are set at five discrete times during the gas day in the DWGM (6.00am ,10.00am, 2.00pm, 6.00pm and 10.00pm) .

27 ASX Victorian Wholesale Gas Futures contracts are cash settled using the arithmetic average of the beginning of the day (6.00am) price for the Victorian wholesale gas market over the period of a calendar quarter.

28 Chicago Mercantile Exchange, *An Introduction to Futures and Options*, 2006, p. 38.

in the ex-ante commodity price. The uptake of successful risk management products is therefore unlikely to develop for the DWGM since traders face unhedgable risks through uplift payments.

In addition, financially traded products typically require a standardised underlying physical product that is commonly traded to reference. This standardisation encourages transactional efficiency and the development of liquidity. The financial gas market is directly linked to the physical gas market and usually evolves from some form of standardised contract for the sale of physical gas. The exposure to uplift payments mean that such a standardised physical product does not currently exist in the DWGM.

3.2 Ability of market participants to manage uplift payment risk

Market prices are set in the DWGM using an unconstrained pricing schedule. Effectively, the pricing schedule represents the DTS as an 'infinite tank' without physical pipeline or pressure constraints on the quantities of gas flows that can be transported from one point in the system to the next..[29]

In reality however, constraints do exist on the DTS and it is not always possible to supply demand from the lowest priced source of gas. Unlike the pricing schedule, the operating schedule does take account of constraints and, where they exist, will schedule out of merit order bids where necessary to meet demand. Ancillary payments are used to compensate the parties who provide out of merit order injections and/or withdrawals. The difference in the marginal prices generated in the pricing and operating schedules forms the basis for any ancillary payments. These payments are then recovered through uplift charges allocated, to the extent practical, to the market participants whose actions led to the ancillary payments being made

The need for AEMO to schedule these out of order injections and/or withdrawals, and hence pay ancillary payments, in any given year has varied considerably. For example, while 2007 and 2008 (to a lesser degree) registered high ancillary payments ($47 million and $600,000, respectively), ancillary payments have only been made in three of the seven years since and have ranged from $9,000 to $15,000 per year.[30]

In 2007, Victoria experienced a particularly cold winter. At the same time, the east coast was suffering a drought which necessitated the use of gas-fired electricity generation due to a lack of access to cooling water for coal-fired power stations. The 2007 winter was also the first winter period under the new DWGM design, implemented following the Pricing and Balancing Review. The testing conditions highlighted some design flaws in the ancillary payment and uplift methodology which were subsequently addressed.[31] In addition, the additional pipeline flow capacity and linepack capacity

---

29 AEMO, *Technical Guide to the Victorian Gas Wholesale Market*, January 2010, p. 29.

30 Data on net ancillary payments provided by AEMO.

31 AEMO's original ancillary payment procedure, implemented in February 2007, was enhanced in May 2008 following the experience in winter 2007. The enhancements were designed to improve market efficiency with the additions of the ancillary payment clawback and flip-flop algorithms. A

provided by the Brooklyn – Corio loop made a material contribution to reducing congestion on the South West Pipeline (SWP) and reducing ancillary payments generally in the DTS.

While ancillary payments have been low (or non-existent) in recent years, this may not necessarily be the case going forward. For example, APA has signed a number of agreements with shippers to expand the capacity of the Victoria - New South Wales Interconnect to accommodate gas flows northwards out of Victoria.[32] In total, these agreements are expected to treble the capacity of the Interconnect,[33] which will allow significant quantities of gas to flow north and may result in constraints emerging elsewhere in the DTS and hence greater levels of ancillary payments in future years.

Uplift payments are charged to market participants to recover the cost of ancillary payments. There are four different types of uplift payments, three of which are intended to allocate uplift payments to those parties whose actions have contributed to the imbalance that needed to be managed (that is, allocating 'cost to cause'), with the fourth type to recover the residual on a pro-rata basis from all market participants.[34] Overall, the total of all uplift payments is designed to equal the total of all ancillary payments for each scheduling interval.

The four types of uplift payment and who they are charged to are:

1. Congestion uplift – to recover ancillary payments caused by congestion on the DTS, charged to market participants who have exceeded their allocation of authorised MDQ (AMDQ) and/or AMDQ credit certificates (AMDQ cc) in a scheduling interval (that is, exceeded their Authorised Maximum Interval Quantity (AMIQ)[35]).[36]

2. Surprise uplift – to recover ancillary payments caused by changes/deviations from scheduled withdrawals or injections, charged to market participants who have deviated from their scheduled quantities.

3. DTS Service Provider Congestion (DTSSP) uplift - charged to the DTS service provider, APA, where it can be demonstrated that it has contributed to

---

further enhancement was made in April 2012 to ensure that market participants were protected against potential financial impacts by rebidding reduced quantities to comply with the NGR. See: AEMO, *Technical Guide to the Victorian Gas Wholesale Market*, July 2013.

32 APA, *APA signs a new gas transportation agreement to further expand its Victoria - New South Wales Interconnect*, ASX Announcement, 24 July 2015; and APA, *APA to further expand VIC NSW interconnect*, ASX Announcement, 4 November 2013.

33 APA, *APA signs a new gas transportation agreement to further expand its Victoria - New South Wales Interconnect*, ASX Announcement, 24 July 2015.

34 AEMO, *Wholesale Market Uplift Payment Procedures (Victoria)*, 1 May 2012, p. 9.

35 AMIQ is a form of authorisation which allows customers to use gas up to a specified interval amount (the 'authorised maximum interval quantity') without attracting the allocation of additional uplift charges which have arisen from congestion on the DTS. On days when congestion occurs on the DTS, market participants whose customers have exceeded their AMIQ/uplift hedge on the day may face congestion uplift charges for their excess or unauthorised use of the DTS.

36 Appendix C provides an overview of AMDQ and AMDQ cc.

congestion by failure to comply with its obligations under the Service Envelope Agreement (SEA).

4. Common uplift – for uplift that cannot be allocated to specific participants; for example, in respect of ancillary payments caused through demand forecast overrides by AEMO. These uplift payments are allocated on a pro-rata basis to all market participants based on their withdrawal quantities on the relevant gas day.

While market participants holding AMDQ or AMDQ cc can use part or all of the associated rights as a partial hedge against congestion uplift charges, those that do not hold these instruments have no means to hedge against congestion uplift charges. In addition, market participants, whether they are holders of AMDQ or not, cannot hedge against surprise or common uplift charges. AMDQ is discussed in detail in section 4.4, including the difficulties in obtaining AMDQ cc and the complexities surrounding trading its associated benefits.

The frequency and magnitude of uplift payments (primarily congestion uplift, but also surprise uplift) currently provide short-term signals for long-term investment in the DTS (that is, to build-out constraints). Uplift payments are used to fund ancillary payments which, in turn, arise because constraints within the DTS require the operating schedule to include higher priced injection offers or withdrawal bids than the pricing schedule (which assumes the DTS is unconstrained). The investment signals provided currently by uplift payments are discussed in detail in section 4.3

The two primary issues that have been raised with the methodology for allocating uplift payments are:

- complexity; and
- they do not allocate 'costs to cause' in the recovery of ancillary payments.

Each of these is discussed in the sections below.

3.2.1 Complexity of uplift payments

At a high-level, the allocation concepts themselves are not overly complicated, namely:

- Congestion uplift is allocated to those parties who have exceeded their AMIQ (that is, participants who have exceeded their allowed maximum quantity of capacity to use in an interval in the DWGM).
- Surprise uplift is allocated to those parties who have deviated from schedules or changed their demand forecasts during the day without, for example, making any compensatory arrangements to rebalance injections and withdrawals.
- DTSSP is charged to APA, where it can be demonstrated that the DTS service provider has contributed to congestion by failure to comply with its obligations under the SEA.

- Where it is not possible to allocate uplift charges to congestion, surprise or to DTSSP uplift, then the residual amount (common uplift) is shared between all market participants in proportion to their daily withdrawals for that day.

While relatively simple concepts, the process to calculate the appropriate allocations are very detailed and complex. The complexity derives from there being multiple schedules each day, with participants able to rebid their injections and controllable withdrawals and to re-forecast their uncontrollable withdrawals as the day progresses.

Consequently, market prices and scheduled quantities can change from schedule to schedule. The requirement for injections and withdrawals that generate ancillary payments can change and as a result there can be positive and negative ancillary payments from schedule to schedule.[37]

3.2.2 Allocating ancillary payments on a 'cost to cause' basis

The complexities outlined above are compounded by the intent to allocate ancillary payments to participants on a ‘cost to cause’ basis. This relates primarily to the allocation of ancillary payments between surprise and congestion uplift.

It is not possible to identify uniquely separable components of ‘congestion’ and ‘surprise’ uplift and so the methodology adopted by AEMO is an approximation of a 'cost to cause' allocation.

The daily capacity of a pipeline to transport gas is dependent on a number of factors, including:

- the physical size (diameter) of the pipeline;
- location of injection and withdrawals along the pipeline length;
- injection pressures and available compression;
- injection and withdrawal profiles throughout the day; and
- linepack.

Pipeline constraints in the DTS therefore arise due to an inter-related combination of pipeline size and compressor capacity, locational and inter-temporal factors. The concept of pipeline constraints being comprised of independently separable components of surprise and congestion was a theoretical attempt to allocate ‘cost to cause’ to the extent practicable while recognising that it will only ever provide an approximation.

This is illustrated under the pricing schedule, which assumes it is always possible for gas from any source to meet demand securely, regardless of ‘surprises’, or unexpected

37 A negative ancillary payment is a payment from a market participant to the market, while a positive ancillary payment is a payment from the market to a market participant.

changes from forecast demand or scheduled injections, or the projected temporal or locational distribution of demand across the system. Hence, surprise uplift itself can be considered to be due to congestion, or at least due to there being limited pipeline capacity and access to linepack.

In addition, the current congestion uplift allocation methodology is not always based on a cost causation. For example, assuming one market participant exceeds its AMIQ by 1GJ while all other participants operate within their AMIQ, there will always be an allocation of congestion uplift despite this not necessarily meaning that there is actual pipeline congestion.[38]

Further, the participant who exceeded its AMIQ may be located in a different part of the DTS to where the actions that the ancillary payment reimbursed were required. Put another way, participants may be being charged uplift payments for congestion that they did not actually contribute to. For example, out of order injections may be required in Melbourne, while a participant who exceeded its AMIQ may be located in Iona and have to pay an uplift charge. This is depicted in Figure 4.1 in section 4.

While ancillary payments currently offer a short-term signal for investment, albeit limited (as discussed in section 4.3), it is important that the manner in which these short-term costs are being recovered from participants is efficient.

Many parties that made submissions to the Stage 1 East Coast Review were of the view that the current ancillary payment/uplift charging regime in the DWGM was complex and that these costs should be incorporated in the observed market price. Many submitters were of the view that this would encourage the development of financial risk management products.[39]

3.3 Volume risk

As outlined above, participants can face price risk in the DWGM through the ex-ante commodity market and the uplift charging arrangements. Market participants can also face volume risk when transmission pipelines become constrained in terms of not being able to withdraw the physical volumes they demand.

One example of volume risk arises if a market participant does not have tie-breaking rights at a location by holding AMDQ or AMDQ cc. A tie-breaking right means that when two participants have bid equal prices for gas injections or withdrawals, and only some of their combined total bid quantity is required or can physically be delivered into or from the system, a participant with assigned AMDQ at that location will be scheduled in priority to a participant without assigned AMDQ. On all other

38 A possible corollary of this on contract carriage pipelines is that overrun charges may be incurred for flows in exceedance of a shipper's contracted capacity, regardless of whether the pipeline is being fully utilised.

39 See for example: AGL, *Discussion Paper submission*, p. 5; ESAA, *Discussion Paper submission*, p. 7; ERM Power, *Discussion Paper submission*, pp. 6-7; GDFSAE, *Discussion Paper submission*, pp. 8-9; Origin, *Discussion Paper submission*, pp. 2-3.

occasions scheduling is based on priced bids, without regard to AMDQ, and so AMDQ does not provide any volume certainty in these instances.

A further, broader, example of volume risk emerges for parties who intend to inject and withdraw the same amount of gas (and hence be removed from imbalance payment risk via their bidding strategies, as outlined above) but cannot due to constraints. If a constraint prevents these parties from either injecting or withdrawing the quantity of gas they desire, then they face a volume risk.

While an important aspect of market design, we understand that, in practice, these risks have been low.

3.4 Value of the ex-ante price signal

An important feature of a liquid market is the presence of a large number of buyers and sellers willing to transact at all times. This allows demand and supply conditions to be reflected in prices so that market participants have access to a meaningful reference price to usefully aid commercial decision making.

As noted above, the majority of gas transacted through the DWGM is by participants who are offering gas to the market and at the same time bidding to have it back (and thus minimising their spot price exposure). This is because, while the DWGM is compulsory, most participants have underlying gas supply agreements in place and do not need to rely on the DWGM for the majority of their needs (only for balancing).

The remaining bids and offers reflect daily imbalances between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. These trades amount to approximately 20 per cent of total volumes based on data available.[40]

Consequently, the observed DWGM ex-ante market price is likely to be susceptible to both a small volume of trades and a small number of market participants.[41] This encourages volatility in the ex-ante market price and adds to the price risk faced by participants who either do not have gas supply contracts to match their withdrawals (as outlined above).

3.5 Conclusions from appraisal

The ability of market participants in the DWGM to manage their risks is currently limited. This includes both specific risk management tools as well being able to adapt their actions to better manage risk.

---

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

41 For a thorough analysis of the value provided by the DWGM ex-ante price signal, please see: AEMC, *East Coast Wholesale Gas Market and Pipelines Frameworks Review*, Stage 1 Final Report, 23 July 2015, pp. 123-124.

An imbalance payment price risk hedge is currently only available to a market participant if it can match its withdrawal volume with an injection (for example, through an upstream gas supply contract). Market participants are currently fully exposed to the ex-ante market price for all withdrawals outside of these contracted positions.

In an efficient market, we would expect the development of financial products that participants could use to hedge their risk in the spot market. While the ASX has released a number of such products, it appears that the DWGM exhibits a number of characteristics that may limit the uptake of these products. These characteristics include:

- parties not being able to take equal but opposite positions in the spot and futures market for a particular quantity of gas because uplift payments are determined ex-post and not known before;
- the lack of a standardised physical product that financial products can reference; and
- the vast majority of participants are effectively managing wholesale price risk by buying wholesale gas straight from upstream producers, and then selling it to themselves through the DWGM using bilateral contracts.

Without mechanisms that all participants can use to manage price risk in the DWGM, confidence in the spot market is lowered, which lowers competition and liquidity. Without a high degree of competition and liquidity in the DWGM, market participants are unlikely to consider the observed price a meaningful reference price reflective of underlying supply and demand conditions that they usefully aids their commercial decision making. This will likely deter new entrants to the DWGM, particularly where those new entrants do not currently have upstream gas supply contracts.

Further, there appear to be a number of issues associated with the manner in which the costs of balancing actions taken by AEMO are recovered from market participants. Specifically, the costs of these actions are intended to be recovered from market participants who caused these actions. However, the recovery of these ancillary payments, via uplift charges, may be resulting in a number of inefficiencies, namely:

- participants may be being charged congestion uplift when the system is not actually congested; and/or
- participants may be paying uplift charges when their actions have arguably not contributed to action needed at other locations and therefore there is no direct relationship between the charge and payment.

While ancillary payments have been low (or non-existent) in recent years, this may not necessarily be the case going forward as demand across the DTS is anticipated to increase. Specifically, significant investment has recently been undertaken that allow large quantities of gas to flow north out of the DTS and may result in constraints emerging and hence greater levels of ancillary payments in future years. It is therefore important that the market arrangements are appropriately structured to accommodate the changing needs of market participants (and potential new entrants).

4 Signals for investment

For efficient and timely investment to occur, investors need clear signals around the need for capacity extensions and expansions (augmentations). These signals enable potential investors to make informed decisions around the size, location and timing of pipeline investment. Investors also need adequate incentives in order to commit to, and undertake, efficient and timely investment. Specifically, they need certainty that the benefits they will receive from undertaking the investment (be it financial, physical or competition related benefits) will outweigh the costs.

This chapter considers the signals for investment provided through the existing market arrangements, and looks at opportunities to improve these signals to facilitate timely and efficient investment in pipelines. Chapters 6 and 7 then explore the ability of existing regulatory and market arrangements to deliver pipeline investment in the DTS that is efficient and on time.

4.1 Planning information

There are no regulatory or statutory obligations on any party to invest in DTS pipeline expansions or extensions. APA GasNet, as the DTS service provider, has no obligations to augment the DTS to meet additional demand growth or supply requirements.[42] AEMO, as the market and system operator, has no responsibility or any powers to invest, or direct investment, in the DTS.[43]

However, AEMO does has a significant role in producing planning information which is used to inform APA GasNet in the development of its access arrangement, and by the AER in making its decision as to whether forecast capital expenditure for proposed system augmentations represent a "prudent investment" for inclusion in the DTS capital base. The information produced by AEMO for this purpose includes independent forecasts of gas demand, independent modelling of pipeline constraints and information on the market impacts of these.

Some of the planning information prepared by AEMO is made publically available through the annual Gas Statement of Opportunities (GSOO) and Victorian Annual Gas Planning Report (VGPR) (now being produced as an attachment to the GSOO).[44] These

42 While APA GasNet has no obligations to expand or augment the DTS to meet additional demand growth or supply requirements, it does have obligations to maintain and make available DTS assets that are set out in the Service Envelope Agreement (SEA) between AEMO and APA GasNet. The SEA sets out the operating limits for the pipeline and pipeline assets (such as compressors, regulators etc.), within which AEMO must operate, along with maintenance requirements and operating practices.

43 This is quite different from the arrangements in the National Electricity Market where transmission network service providers do have obligations to provide and maintain adequate capacity to meet demand requirements within a specified reliability standard.

44 As part of its GSOO/VGPR responsibilities, AEMO is responsible for the production of medium-long term demand forecasts and, as the market and system operator, is responsible for short term demand forecasts for operational and market decision making and scheduling purposes.

documents include demand forecasts, and identify potential system constraints and, hence, opportunities for investment in pipeline extension or expansion, and gas supplies.

It is generally recognised that neither document is intended to contain all the information needed for making investment decisions.[45] However, while useful in identifying potential opportunities for investment in pipeline capacity, there are limits to the extent to which this information can be relied on to drive investment decisions, and justify forecast capital expenditure to the AER.

Discussions between AEMO and APA GasNet over recent years have assisted in developing a much better understanding of the forecasting and planning processes that each undertakes, and the likely impact of operational actions and decision making on market outcomes. There is now a regular and cooperative dialogue between the two organisations on these matters. Through this process, there is also greater awareness of, and provision in the planning processes for, the potential impacts of flows from Victoria to New South Wales or South Australia. However, given the information asymmetries between AEMO (and the AER) and market participants, the former will be limited in its ability to precisely define future pipeline investment requirements.

In proposing forecast capital expenditure to the AER, APA GasNet can choose to offer information and evidence of its own to supplement (or counter) information presented by AEMO in its GSOO/VGPR. This information may include that provided by shippers, customers or producers who have approached APA GasNet regarding new connections, or requirements for additional pipeline capacity.

In addition, APA GasNet may choose to submit to the AER information and evidence observed in the market and which provides some insight into market participants' future transportation requirements. There are a number of mechanisms in the DWGM which could be used by APA GasNet, and also by market participants and potential new entrants, to support decisions on whether to pursue expansion or augmentation of the DTS. These are explored in the next sections.

4.2 Observed market prices

Prices observed in most markets are generally considered to be efficient at providing an important investment signal. Specifically, when prices are relatively high, current and potential market participants are incentivised to invest in supply- and demand-side initiatives. Where networks are regulated with the intention of achieving the

45 For example, the GSOO only provides highly aggregate supply, demand and capacity modelling based on limited scenarios. This does not address specific constraints within transmission systems – only that constraints may exist under some scenarios. Further, while the VAPR provides more detail on Victorian specific planning matters, AEMO is only required to produce information on peak daily and hourly granularity. There is also no requirement for AEMO to publish information on linepack adequacy. Although the VAPR does set out the capacity of available LNG to meet within day peak load balancing requirements, it does not address any other condition that results in intraday or locational linepack shortages requiring LNG.

outcomes observed in efficient markets, high observed prices on account of constraints should incentivise network owners to invest to alleviate these constraints.

As outlined in section 3.2, the ex-ante market price observed in the DWGM is determined using a pricing schedule that assumes there are no constraints in the DTS. While assuming away zonal constraints within the DTS for the purposes of setting the market price encourages trading liquidity, it has the implication that market prices alone give no indication of whether capacity investments are required, that is, whether the network is constrained. The current DWGM market design does provide an investment signal via the ancillary payment mechanism, albeit this signal is limited (as outlined in section 4.3 below).

Further, as outlined in section 3.1, participants in the DWGM with gas supply contracts can be expected to hedge their exposure to the ex-ante market price by bidding and offering at $0/GJ and $800/GJ, respectively. As a result, the observed market price reflects the expected daily imbalance positions between participants' requirements and contractual positions, and any sole injectors or withdrawers without underlying contracts. It may therefore be expected that the market price could be counterintuitively low during times of constraint as participants bid to ensure their gas is scheduled.

4.3 Ancillary payments and uplift charges

As outlined in section 3.2 above, ancillary payments may arise due to constraints on the DTS pipeline system and are a result of having one unconstrained pricing schedule for the entire system. Specifically, when it is not possible to meet demand with the lowest priced source of gas (because there is a constraint), then AEMO has the ability to schedule 'out of order' injections and/or withdrawals to rectify any imbalance.

The stylised example below illustrates how ancillary payments are made in the DWGM currently. Specifically, for the purposes of this example, it has been assumed that:

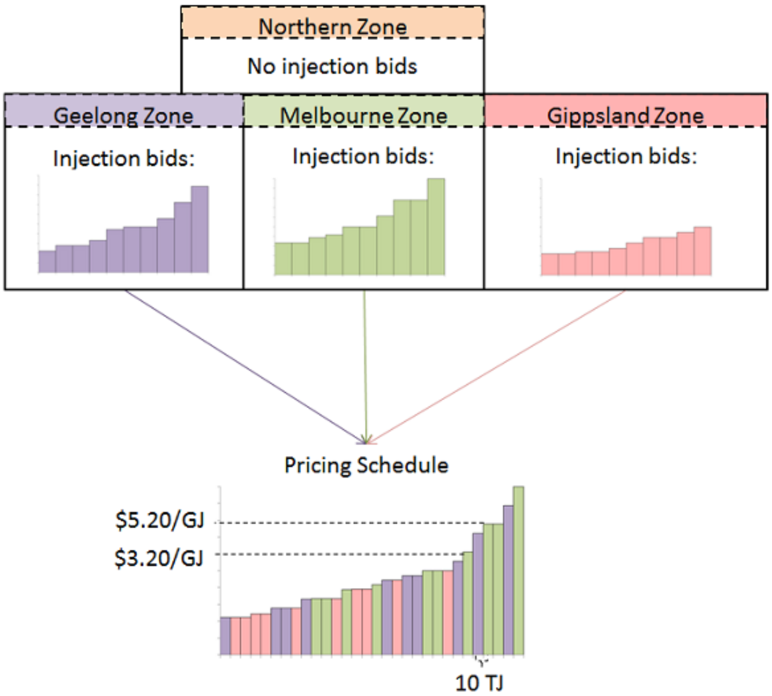
- The DWGM can be represented using four zones, being: the Northern Zone; the Geelong Zone; the Melbourne Zone; and the Gippsland Zone.[46]
- Injections can only physically occur within the Geelong, Melbourne and Gippsland zones.[47]
- There is a constraint that causes AEMO to schedule an additional 10 TJ of injections in Melbourne Zone.

This example is illustrated in the figure below.

46 These five zones have been based on the existing Market Clearing Engine assumed network topology configuration. See: AEMO, *An Overview of the Vic Gas Market (DWGM)*, Workshop Material, workshop given 23 January 2013 at the AEMC offices, p. 2-10.

47 We have assumed that the Northern Zone is only used for withdrawals during the period of interest

Figure 4.1 Overview of ancillary payments in the DWGM



Source: AEMC. Note: it has been assumed that all injection bids are for the same quantity.

In this example, the pricing schedule generates an ex-ante market price of $3.20/GJ, which applies to all scheduled withdrawals and injections across the DTS (including the 'out of order' injection in the Melbourne Zone). An ancillary payment is also made to the 'out of order' injection in the Melbourne Zone equal to $20,000 (that is, $2/GJ x 10 TJ).

Under the current system of ancillary payments, participants can only observe that ancillary payments have been made for the entire system and there is no direct link as to why they have been made, that is, which portion(s) of the DTS were constrained. While we understand that bids are published after the event and participants may be able to extract from this information the bids that have not been scheduled (and use this to derive where the constraint lie), this does not offer a direct signal. Further, as outlined in section 4.1 above, while we understand that there is regular and cooperative dialogue between the AEMO and APA GasNet on forecasting and planning processes, information relating to ancillary payment causing constraints is not publically available to market participants.

The current system of ancillary payments (and associated uplift payments) may also result in participants paying for congestion that they arguably do not contribute to. In the stylised example above, participants located in any of the four zones outside of Melbourne may be liable for uplift payments even though they did not inject or withdraw in Melbourne zone (and hence did not contribute directly to the constraint). As noted above, having one unconstrained pricing zone across the DTS means that there are weak signals for investment in constrained parts of the DTS. This may create problems as demand across the DTS increases and significant and persistent constraints emerge.

As outlined in section 3.2, any allocation of uplift between congestion and surprise will only ever be an approximation and the uplift allocation mechanism can be considered to never fully allocate 'costs to cause' in the recovery of ancillary payments. The fact that participants do not face a signal that reflects the cost of their actions therefore limits the ability of the ancillary payment and uplift payment mechanisms to be used as a strong indicator of the need for investment.

As outlined in section 3.2, the methodology associated with allocating congestion uplift may result in some participants paying congestion uplift irrespective of whether the system was actually experiencing pipeline congestion. This presents a price signal to these participants to amend their behaviour in response to a problem that is not actually occurring and so, in these instances, does not provide a useful signal.

Further, ancillary payments only occur when limitations in pipeline capacity and accessible linepack exist and congestion is already an issue. The frequency and magnitude of ancillary payments (and associated uplift charges) therefore provide a backward looking signal and so may not result in optimally timed investment. Although ancillary payments will tend to increase as constraints become more frequent, it is likely to already be too far into the five year access arrangement and revenue setting cycle to be used as a leading indicator of investment.

4.4 Availability of AMDQ and AMDQ cc

Investment in the DTS could be signalled by the availability and ability of new entrants or market participants with increasing requirements to access AMDQ and AMDQ cc, either for an uplift hedge or an injection/withdrawal tie breaking right. This is because the demand for AMDQ and AMDQ cc relates to participants' perception of the benefits afforded to them in holding capacity. That is, market participants will seek to hold (and will be prepared to pay a premium for) AMDQ and AMDQ cc when the pipeline system is constrained as a hedge (that is, a risk management service) against the risks of curtailment and the payment of uplift charges at the particular locations.[48]

However, relying on demand for AMDQ or AMDQ cc to signal the need for investment in the DTS may not result in optimally timed or efficient investment for several reasons.

First, the process of creating and allocating new AMDQ cc occurs only after an extension or expansion has already occurred, and after APA GasNet and AEMO have agreed on the increase in pipeline capacity and, hence, the number of new certificates to be created. In other words, investment in pipeline capacity occurs before the market has signalled its commitment to purchase AMDQ cc through the allocation process. In

48 This means that the demand and supply of AMDQ and AMDQ cc could be different at different locations.

this sense, the demand for new AMDQ cc is a backward looking signal which may not result in optimally timed investment.

In addition, there a number of barriers which currently limit market participants' ability to acquire existing AMDQ and AMDQ cc to meet their risk management needs.[49] If market participants were able to access underutilised uplift hedge or tie breaking rights, they may not need to seek out new AMDQ cc for this purpose. This means that while demand for new AMDQ cc may provide a signal of market participants' desire to access the benefits attached to AMDQ and AMDQ cc, it may not necessarily provide an accurate indication of pipeline capacity constraints, and thus an accurate signal of the need for new investment. This is likely to be the case where underutilised uplift hedge/tie breaking rights exists, but new entrants or market participants are unable to access them.

Price of AMDQ cc

A related issue is the price paid by market participants for AMDQ cc. It has been argued by APA GasNet in the past that the price of AMDQ cc is critical in providing a leading form of capacity signal under the market carriage model.

Until the most recent access arrangement period, AMDQ cc has been allocated through a tender process and bundled with the associated transportation (injection) of gas for that location.[50] APA GasNet has set the price for this bundled product and market participants have bid for quantities of daily capacity made available. Where bids total more than the total of new capacity available, APA GasNet has allocated the available capacity on a pro-rata basis according to the capacity tendered for by each bidder.

The ability of APA GasNet to charge a price that is higher than the reference tariff relates to the demand for AMDQ cc and market participants' perception of the benefits afforded to them in holding AMDQ cc. That is, parties are prepared to pay a premium for a hedge against the risks of curtailment and the payment of uplift charges when the pipeline system is constrained.

However, in its 2013 decision for the DTS, the AER classified AMDQ cc as a reference service and, in line with the rules in place at that time, applied a reference tariff based on the costs of providing the service. At the time of making the decision, the AER recognised that the reference tariff reflected only the issuance costs of AMDQ cc (which are very low) and not the value that market participants may place on AMDQ cc. The AER also set the tariff on a throughput basis.

APA GasNet has argued that the AER's decision undermines its ability to use the AMDQ cc mechanism as a way to support investments in injection capacity and that it can no longer gain any certainty of throughput or revenue from its allocation of AMDQ cc. It considers that the decision to set an administratively based priced for

49 These barriers were explored in the recent Portfolio Rights Trading rule change request.

50 The operation of the tender process administered by APA GasNet for AMDQ cc is not specified in the NGR, the current access arrangement for the DTS, or by AEMO. The price set by APA GasNet could be equal to or higher than the relevant injection reference tariffs.

AMDQ cc (as opposed to allowing the market to determine the price) has undermined a fundamental aspect of the design of the DWGM that was intended to provide some kind of investment signal and support for capacity rights at injection points.[51]

Box 4.1 Reference service and rebateable service definitions rule change

On 5 August 2011, the AER submitted a rule change proposal to the AEMC seeking to amend the National Gas Rules (NGR) which, at the time, required the AER to apply a reference tariff to all pipeline services that were likely to be sought by a significant part of the market (that is, to all 'reference services'). The AER also sought a change to the definition of a 'rebateable service'.[52]

The AER sought this change in part to address unregulated revenue received by APA GasNet from the sale of AMDQ cc. It submitted that in the instance AMDQ cc was determined to be a pipeline service, it would be difficult to determine an efficient tariff for AMDQ cc for commercial and/or technical reasons. It therefore sought the discretion not to set such a tariff.

On 1 November 2012, the AEMC amended the NGR to provide the AER with greater flexibility in setting reference tariffs for pipeline services classified as reference services. This was to ensure the AER would only be required to set a reference tariff where it was practicable and efficient to do so. However, the AEMC determined that the amended rule (which commenced on 2 May 2013) should not apply to the 2013-2017 access arrangement period for the DTS. The AER's 2013 decision was therefore made under the previous rules.

APA GasNet's access arrangement revision proposal for the 2018-2022 access arrangement period is due in December 2016. As explained in Box 5.1, the AEMC's reference and rebateable services rule change is now in effect. Going forward, the AER has the ability to continue to classify AMDQ cc as a reference service for the next access arrangement period, but may or may not decide to set a reference tariff for AMDQ cc. Alternatively, the AER may choose not to classify AMDQ cc as a reference service, potentially leaving it open to APA GasNet to decide how to price AMDQ cc (as has been the case in the past).

The link between the provision of AMDQ cc, and signals and incentives for investment on the DTS, is not straight forward and has been subject to divergent views at different times.[53] With uncertainty around how the AER will classify AMDQ cc in the next access arrangement for the DTS, and the uncertainty around how the DTS service

---

51 APA Group, *Discussion Paper submission*, 26 March 2015, p.14.

52 AEMC website, available at: http://www.aemc.gov.au/Rule-Changes/Reference-service-and-rebateable-service-definitio

53 AEMC, *National Gas Amendment (reference service and rebateable service definitions) Rule 2012*, 1 November 2012, p. 45.

provider will allocate and price AMDQ cc in response[54], AMDQ cc cannot be relied upon to provide an effective signal of the need for investment on the DTS.

4.5 DTS demand growth

The case for regulated pipeline investment (that is, for extensions or expansions that becomes part of the capital base of the pipeline) could also be signalled by a reduction in the ability of the system to deliver previously achievable withdrawal capacities at some locations (for example, the Interconnection at Culcairn) due to general underlying demand growth across the system. This would manifest itself through it becoming increasingly difficult at times of high system demand to maintain system operating pressures at some locations within the limits specified in the Service Envelope Agreement (SEA) between APA and AEMO, and system security procedures. Eventually, without system augmentation, withdrawals may need to be limited under some circumstances. This issue is discussed further in chapter 8.

4.6 DTS planning standard

AEMO and APA GasNet are required to maintain an agreed common system model that, among other things, is used to determine system capacities. This is important for the following:

- Determining the impact on system capacity of planned and unplanned pipeline or plant outages. This may be required for market information prior to planned outages, or the allocation of DTS service provider uplift – if APA GasNet fails to meet its SEA obligations and this results in ancillary payments due to transmission constraints.
- Determining the additional pipeline capacity created by pipeline expansions/augmentations for the allocation of AMDQ cc by APA GasNet.
- Providing information to the market and to regulators on potential future pipeline constraints for future investment and approval of regulated investment.

At times, there have been differences in views between APA GasNet and AEMO regarding some of the assumptions used in the common model and other matters under the SEA. While we understand that these have generally proven to be resolvable, one point of difference that remains a concern relates to the approach to determining pipeline capacity. This issue has come to the fore recently in the context of the additional export capacity via the Interconnect at Culcairn as a result of northern zone system expansions.

In determining the additional firm export capacity provided by the expansion works at Culcairn, AEMO has required that the additional capacity be supportable over five

54 Although the AER may choose to set a reference tariff for AMDQ cc, charging of the tariff can be difficult to enforce, In addition, APA GasNet could alter the reference service and thus sell AMDQ cc as different service and at a different price.

consecutive 1 in 20 peak demand days. This is to ensure that the conditions under which that additional capacity can be supported are stable.[55] However, APA GasNet's view has been that the assumption of consecutive peak demand days is overly conservative. It argues that a conservative approach to determining capacity may lead to more investment than is necessary in order to achieve the required capacity within the system or at injection/withdrawal points.[56]

There is no statutory planning standard for the DTS in Victoria. The 1 in 20 planning and system security standard was "inherited" from the pre-privatisation, pre-spot market, Victorian Gas and Fuel Corporation standard and is consistent with system security standards in use in some international gas systems, including the UK.

To remove uncertainty and provide greater clarity and understanding around the approach to determining pipeline capacity in the DTS, there may be merit in reviewing the appropriateness of the current 1 in 20 planning standard for the DTS. Such a review would be timely ahead of APA's next access arrangement submission in that it may provide an agreed standard against which to assess proposed system augmentation projects for inclusion in APA GasNet's capital base. As part of this review, alternatives to the "1 in X" standard could also be considered (for example, a net benefits test using some value of customer reliability).

4.7 Conclusions from appraisal

The issues with the current uplift and pricing mechanisms, and with the AMDQ cc allocation process, discussed in this section indicate that they are not fully effective in signalling to the market the need for investment in new DTS pipeline capacity.

Reliance on market price alone does not provide efficient price signals since the ex-ante market price observed in the DWGM is determined using a pricing schedule that assumes there are no constraints in the DTS. In addition, reliance on actual frequency and magnitude of uplift payments, or a shortage of available AMDQ, is a backward looking signal, which may not result in optimally timed investment.

The GSOO and VGPR do have a role in identifying the opportunities and indicate likely timing requirements for augmentation to the DTS. While market participants have views of the usefulness of some aspects of these planning documents, we understand that overall feedback on the GSOO and VGPR has generally been positive.

AEMO (and VENCorp before it) has undertaken a number of reviews and considered a range of options for improving the current market signals for investment in the DTS. It has done this in consultation with, and with the direct involvement of, market

55 Otherwise it would be possible to run a single case with favourable starting conditions (for example, the northern zone being "primed" with linepack) that may not be replicated every time participants seek to schedule high levels of export.

56 APA Group, *Submission to East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Public Forum Discussion Paper, 26 March 2015, p.16

participants and stakeholders. However, the ability to implement any significant improvements has been held up with the recurrence of a number of key issues:

- Reduction of market complexity and simplifying the wholesale pricing mechanism is likely to dilute market price signals for pipeline augmentation even further.
- Consideration of price simplification cannot be divorced from consideration of AMDQ or alternative transmission capacity rights.
- Due to the meshed nature of the DTS, and prevalence of within day constraints, any alternative capacity rights regime is likely to involve some degree of complexity in defining the rights and providing clear signals for investment.

Consideration of incremental changes to the DWGM arrangements to improve the investment signals provided by market prices and capacity rights will also need to have regard to these matters.

5 Regulatory framework

While the DWGM arrangements provide a form of tradable property rights, through AMDQ and AMDQ cc, these rights have limitations in terms of providing certainty of access when the pipeline is constrained, and in allocating “free rider” access when spare capacity is available. Consequently, they have been of limited effect in supporting private pipeline investment in the DTS. In the absence of privately funded pipeline augmentations, the other avenue for investment is through the regulated investment process. Currently, investment decisions to augment the DTS are generally made as part of the five yearly reviews by the AER of APA GasNet's access arrangement for the DTS.

This chapter outlines the perceived issues with the regulatory framework for investment in the DTS. Specifically, it considers whether the current regulatory framework provides the right incentives and opportunities for the DTS service provider (APA GasNet) to make efficient and timely investments. Chapter 6 then explores the reasons why the current DWGM arrangements have had limited effect in supporting private pipeline investment in the DTS.

5.1 Regulatory investment process

The DTS is a fully regulated pipeline under the NGR. Currently, APA GasNet relies primarily on the regulatory process to fund new investment in the DTS. The AER approves the access arrangement for the DTS, including the reference tariffs to be paid by market participants.

While investment is usually approved through the regulatory process, the decision regarding what assets to invest in rests solely with APA GasNet. AEMO provides demand forecasts and planning information in the GSOO and the VAPR that assist APA GasNet in making investment decisions. However, there is no requirement that the DTS must meet that demand forecast.[57]

APA GasNet may also choose to invest in the DTS outside of the regulatory process. However, if the asset is not included in the capital base, the service provider would not recoup those costs through the reference tariffs paid by all market participants. APA GasNet would need to absorb the costs or recover those costs through other means (such as a capital contribution).

Rules 79-86 of the NGR set out the capital expenditure related provisions that apply to fully regulated pipelines.

57 There are some requirements for APA GasNet to provide supporting services to AEMO to operate the DTS, outlined in the Service Envelope Agreement between APA GasNet and AEMO.

Rule	Overview
New capital expenditure (79)	Rule 79 sets out the matters the AER must consider when determining whether or not capital expenditure can be rolled into the capital base. Conforming capital expenditure is capital expenditure that: • would be incurred by 'a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services'; and • is justifiable on one of the specified grounds. The service provider applies using at least one of these, and the AER approves using at least one of these, but the decision may vary from the application.
Advanced determination (80)	Rule 80 allows the service provider to seek an advanced determination from the AER on whether capital expenditure will meet the criteria in rule 79. This intra period determination is binding for the next access arrangement decision.
Non-conforming capital expenditure (81-84)	Rules 81-84 set out how non-conforming capital expenditure can be treated. While it does not form part of the capital base, a service provider can still carry out this investment (rule 81). Options for recovering this expenditure include: • Receiving a capital contribution (rule 82); • Recovering the expenditure through surcharges (rule 83). The AER must be satisfied the surcharge would not exceed non-conforming expenditure 'incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowers sustainable costs of providing services'; • Placing the non-conforming capital expenditure in a 'speculative capital expenditure account' (rule 84). The fund increases each year at a return determined by the AER. If the expenditure becomes conforming in the future (under rule 79), the relevant proportion of the fund can be included in the capital base with a return and depreciation adjustment.
Redundant assets (85-86)	Rule 85 allows an access arrangement to include a mechanism for: • assets that cease to contribute *in any way* to the delivery of pipeline services to be removed from the capital base at the commencement of the next access arrangement period; and • the costs associated with a decline in demand to be shared with users. Rule 86 provides for redundant assets to be later returned to the capital base if it later complies with rule 79.

5.2 Investment risks

Owners of unregulated contract carriage pipelines are able to manage the risks of investing in pipeline infrastructure. They may secure long term contracts with market participants and apply suitable tariffs, providing an assurance that the pipeline owner will receive income for its investment for the length of any contract. Take or pay contracts shift the risk of demand reduction to the market participant.

Owners of regulated contract carriage pipelines may also secure long term contracts, but the access arrangements, including reference tariffs, are approved by the AER. Capital expenditure will only be recouped through reference tariffs if it meets the regulatory criteria set out above. However, the ability to enter into long term capacity contracts gives the owner some indication of the level of utilisation in the pipeline and whether it can expect to have customers in the long term.

The DTS is not only a regulated pipeline, but also operates within a market carriage system. Market participants are unable to secure firm, long term capacity rights. This means that in addition to having little control in determining the reference tariffs paid by market participants, there is some uncertainty for APA around long term utilisation of the pipelines. Forecasts provide some assurance, but if demand for pipeline capacity suddenly reduces, the redundant asset provisions in the NGR create a risk that those particular assets may become stranded.

The uncertainty around long term demand for pipeline capacity in the DTS has been exacerbated by the increased volatility in the east coast market in recent years. Previously, Victoria may have experienced fluctuations in demand throughout the year from its residential and industry customers, but it was relatively predictable. The DTS is now used by both Victorian customers and for 'exports' to other jurisdictions. Demand is exposed to wider influences and is potentially more volatile and difficult to predict.

It is also risky for market participants to underwrite expansions to the DTS, because it is a market carriage model. While they may receive AMDQ cc for their contribution, there is no guarantee that they may access that capacity if they are outbid by another market participant. This 'free rider' risk deters private investment (discussed in Chapter 6).

5.3 Intra-period investment opportunities are not being utilised

Service providers for regulated pipelines may choose to defer investment opportunities that arise during an access arrangement period until the next access arrangement period because of the risk that the investment will not be included in the capital base.

To address this issue, the NGR includes a provision that allows service providers to obtain an advance determination. This involves the AER determining whether expenditure meets the criteria in rule 79. This determination is binding on the AER and provides an assurance that the expenditure would be included in the capital base for the subsequent access arrangement.

It does not appear that the advance determination has been used since 2006. The ACCC agreed to GasNet's application on forecast new facilities investment under section 8.21 of the Gas Code (equivalent to rule 80) for its Corio loop near Brooklyn. The effect of the decision was to bind the ACCC when it considered revisions to the access arrangement in 2007.[58] The ACCC had not agreed to this investment in the 2003-07 access arrangement. However, the investment became urgent and APA sought an advance determination towards the end of the access arrangement period.

While an advanced determination is binding on the AER (that is, the asset will be included in the capital base in the next access arrangement), it doesn't change the reference tariff during the current access arrangement period. APA GasNet is unable to recover costs for that asset for the years until the next access arrangement period. However, if required, APA GasNet could seek a variation to the access arrangement under rule 65 of the NGR, or an acceleration of the review submission date under rule 51.[59] Although this process may require internal resources for APA GasNet, it would include the asset in the capital base and update the reference tariffs.

As mentioned above, there is no requirement for APA GasNet to invest in the DTS. To the extent that there is an issue with intra-period investment, it is an issue for all regulated pipelines and not specifically the DTS. This provision was included in the Gas Code prior to the NGR and no party has sought a rule change on this issue to date.

While there are some inconveniences for services providers using the advance determination, we consider that there are more significant issues facing APA GasNet that have affected timely and efficient investments. Within a market carriage context, the redundant asset provisions create a long term investment uncertainty for APA GasNet with regard to its assets (discussed in section 5.6 below).

5.4 Speculative account for non-conforming expenditure

An access arrangement can provide that an amount of non-conforming capital expenditure be placed in a speculative account, with a rate of return to be decided by the AER.[60] It has not been used for a long time and there is a question as to whether it is currently facilitating timely and efficient investment.

One of the issues is that the purpose or role of the account is unclear, given the other regulatory investment provisions. Some consider the purpose of the speculative account is to encourage more efficient investment in greenfields pipelines. For example, instead of building a 50TJ pipeline at $80m to meet current demand, a service provider could build a 100TJ pipeline at $100m and place the $20m in a speculative account. So long as demand increases, it is more efficient to build one larger pipeline than two smaller pipelines at different times.

---

58 ACCC, *GasNet Australia: Major system augmentation - Corio loop*, June 2006. Available at: http://www.aer.gov.au/node/9041.

59 To accelerate a review submission date under an access arrangement, a trigger event specified in the access arrangement must be satisfied.

60 Rule 84 of the NGR.

However, if an investment is considered efficient and there are good reasons to over-invest, the capital expenditure would likely be conforming under rule 79.[61] Capital expenditure could be rolled into the capital base at a future date if it becomes conforming under rule 79 without the need for a speculative account. On the other hand, there seems to be little harm in APA GasNet placing an amount into such an account, on the chance it becomes conforming in the future. The speculative account provision has existed since the Gas Code and there was little discussion of its purpose when it was incorporated into the NGR in 2008.

An example of its use was in the 2000-10 access arrangement for the Central West Pipeline. AGL Pipelines placed $2.78 million in a speculative account and built a pipeline that was oversized for that portion of the pipeline network, but would be added to the capital base once a further planned pipeline was built and the additional capacity was utilised.[62] The rate of return was determined when the speculative assets were rolled into the capital base.

More recently, APA GasNet proposed setting up a speculative account, with a rate of return for the speculative account slightly higher than that expected to be applied to the capital base. This higher rate of return would account for the speculative and more risky nature of the expenditure, as there is no certainty that the speculative expenditure would be included in the capital base in the future. However, the nature of the investment was not provided by APA GasNet at the time. The AER decided that it would not specify or provide a different rate of return for a speculative account until the nature of the investment is known.[63] While APA did not provide the nature of the investment at the time, knowing a rate of return for a speculative account upfront may have assisted APA GasNet to assess the risks and decide whether to consider a non-conforming investment.

We note that any issues related to the speculative account are not unique to the DTS, but would apply to all regulated pipelines. Before considering minor improvements to the speculative account provisions[64] it would be important to clarify its role in supporting regulatory investment.

61 Investment can be 'lumpy' and it may be necessary to slightly overinvest. For example, compressors may only come in particular sizes and there may be a choice between installing infrastructure that is too small or too large for current demand.

62 ACCC, *Access arrangement by AGL Pipelines (NSW) for the Central West Pipeline*, Final Decision, June 2000, pp. 64-68. Available at: http://www.aer.gov.au/node/4781.

63 AER, *Access arrangement final decision: APA GasNet Australia 2013-17: Part 2 Attachments*, March 2013, pp. 94-95.

64 Minor improvements could include clarifying requirements for AER in determining a rate of return for the account, or clarifying the types of expenditure that can be included in the speculative account (see AER, *Access arrangement final decision: APA GasNet Australia 2013-17: Part 2 Attachments*, March 2013, pp. 51-53).

5.5 Incentives to allow congestion to persist

Section 4.4 discussed the potential for the demand for AMDQ and AMDQ cc to be used as a signal for investment. It also discussed APA's view that the price of AMDQ cc has, in the past, provided it with a leading form of capacity signal under the market carriage model.

A related issue raised by stakeholders and other reviews is that APA, as the owner of the DTS, may have an incentive to allow congestion to persist because it can derive additional revenue from the sale of storage capacity in the Dandenong LNG facility, and from the sale (via tender or auction) of higher valued AMDQ cc, both of which currently sit outside the regulatory framework:

- APA is able to earn unregulated revenue from selling capacity at the Dandenong LNG storage which is dependant to some extent on how constrained the DTS is. That is, where the DTS is constrained, market participants may be willing to pay more for Dandenong storage.[65]

- APA is able to charge a price for AMDQ cc that is higher than the reference tariff. In some instances where the DTS is constrained, market participants would be expected to pay a premium for AMDQ cc as a hedge against the risks of curtailment and the payment of uplift charges.

As noted in the Gas Market Scoping Study, while in principle the AMDQ cc allocation arrangements and ownership of the LNG facility may give rise to such an incentive, it is not clear from the information available that APA had acted on this incentive.[66] While this is not to say APA may not act on the incentive in the future, it is unlikely to be an issue over the next access arrangement period given the significant investments about to be undertaken in the DTS.

In addition (and as discussed in Chapter 4) in 2013 the AER decided to set a reference tariff for AMDQ cc for the current access arrangement period based on the administrative cost of providing the service. The AER's decision has effectively removed the ability of APA to derive additional revenue from the sale of AMDQ cc for the current access arrangement period and, in doing so, has removed any incentive to allow congestion to persist in this context. Whether this incentive may return will depend on the outcome of the next access arrangement and whether the AER decides to set a reference tariff for AMDQ cc.

5.6 Redundant assets

Access arrangements can include a mechanism to remove assets from the capital base where they cease to contribute in any way to the delivery of pipeline services.[67] APA

65 Conversely, if APA augments the DTS, the value of Dandenong LNG storage would fall.

66 K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 116.

67 Rule 85 of the NGR. Under rule 86 of the NGR, assets can be returned to the capital base if it later complies with rule 79.

GasNet includes a redundant asset clause in the DTS access arrangement by choice, as the AER could require one to be included if APA GasNet did not.[68]

One of the most significant risks for APA GasNet's investment in the DTS is whether the assets will continue to meet the test in rule 79 over the long term. If unused pipeline assets are found to be redundant, those assets would be removed from the capital base and no longer used to determine reference tariffs.

However, the pipeline operator may be compensated for the inclusion of this clause in an access arrangement. The regulator takes the uncertainty created by this clause into account when determining the rate of return.[69]

While the redundant asset clauses in the DTS access arrangement have not been used by APA GasNet or the AER, in 2005, the Independent Pricing and Regulatory Tribunal (IPART) declared that part of the Wilton to Wollongong pipeline capacity was redundant due to decreased utilisation and removed it from the capital base under section 8.27 of the Gas Code.[70] Jemena Gas Networks sought to have that part of the pipeline returned to the capital base in the 2010 access arrangement review. This was refused by the AER as, in its view, the redundant asset was still not contributing to the delivery of pipeline services.[71]

Despite these investment risks for the DTS, we note that investment has still been occurring. Recently, investment seems to occur where APA has enough certainty over long term demand to mitigate the risks imposed by the existing regulatory arrangements.

For example, APA GasNet decided to expand the northern export capacity of the DTS.[72] This was supported by the knowledge that a market participant had committed to a firm service on the adjoining Moomba to Sydney Pipeline which is also owned by APA. This gave APA some confidence that the market participant requiring additional capacity in the DTS was committed to flow gas through, and enough certainty to invest in new capacity outside the regulatory approval process.[73]

Also, APA has previously relied on the sale of AMDQ cc to confidently invest in additional capacity, beyond what is approved for the capital base. In the past, the sale

68 ACCC required the inclusion of the redundant asset provision for the Central West Pipeline in its 2000-2010 access arrangement. See: ACCC, *Access arrangement by AGL Pipelines (NSW) for the Central West Pipeline*, Final Decision, June 2000, p. 68.

69 ACCC, *GasNet Australian access arrangement revisions for the Principal Transmission System*, Final Decision, November 2002, p. 32.

70 IPART, *Revised access arrangement for AGL Gas Networks,* Final Decision, April 2005, pp. 36-41, 78-89.

71 AER, *Jemena Gas Networks - Access arrangement proposal for the NSW gas networks*, Final Decision (Public), June 2010. pp. 45-46.

72 APA media release, *APA to further expand VIC NSW interconnect*, 4 November 2013.

73 APA Group, *Discussion Paper submission*, p. 13.

of AMDQ cc gave APA some certainty of throughput, as well as revenue[74] (see Chapter 4).

5.7 Conclusions from appraisal

The changes underway in the east coast market (described in Chapter 2) may result in significant changes in the utilisation of some pipelines. Based on our appraisal, the existing regulatory framework appears to provide sufficient flexibility to deal with these changes. That said, a key concern with the framework for regulatory investment relates to the potential uncertainty created by the redundant asset provisions. This uncertainty could have adverse implications for timely and efficient investment in the DTS, in instances where it results in APA GasNet only pursuing pipeline investments where it has certainty that the utilisation of the pipeline will not reduce over the long term.

However, removal of the redundant asset provisions from the NGR in an effort to improve the incentives for timely and efficient investment by APA GasNet would have the effect of transferring the risk of asset redundancy from APA GasNet to end users. If the redundant asset clauses were removed, capital expenditure would remain in APA GasNet's capital base once it was approved by the AER. The AER would be responsible for ensuring that the approved capital expenditure was efficient and market participants would pay for the approved assets through the reference tariffs. However, in the event that gas demand in the DWGM reduced such that there was a significant reduction in the utilisation of a pipeline, market participants would continue to pay for an asset that has become either partially or fully redundant. Given there are limits to the ability of regulators to foresee the capacity needs looking forward, it may be difficult to limit this risk to end users.[75]

In addition, any changes to the regulatory investment provisions in the NGR would apply to all regulated pipelines, not only the DTS. Any changes to the regulatory framework to address this concern would need to carefully consider the impacts on other regulated pipelines.[76]

An alternative to removing the redundant asset provisions in the NGR would be to strength the investment signals that provide APA GasNet with sufficient long term certainty to make investments. If APA GasNet had clearer signals around the future utilisation of a pipeline, it would be in a better position to make efficient decisions around the size, location and timing of pipeline investment and propose these to the AER as part of its access arrangement. A discussion on current signals for investment,

74 APA Group, *Discussion Paper submission*, p. 13.

75 That said, in approving an access arrangement proposal, the AER is required to have regard to the pricing and revenue principles. These require the AER to have regard to, among other things, the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services. These are set out in Section 23 of the NGL.

76 That is, all regulated distribution and transmission pipelines, in all states and territories, now and in future.

including possible options for strengthening these signals, is provided in Chapters 4 and 8.

Overall, investment in the DTS has been occurring, largely as part of the five yearly reviews by the AER. While some concerns have been raised in relation to the regulatory framework and provisions including in the NGR, there is no evidence to suggest that these are, or will in the future, have a significant impact on the incentives for APA GasNet to undertake timely and efficient investment in the DTS. The next chapter considers opportunities for market-led investment in the DTS.

6 Market-led investment

Timely and efficient investment in infrastructure involves additions to, and expansions of, infrastructure that enable supply to meet demand while minimising the cost of excess capacity.

One of the high-level principles the AEMC adheres to in undertaking all rule changes and reviews is that competition and market signals will generally lead to better outcomes than regulation. That is, market forces and the process of competition should result in consumers' needs being met more efficiently than through market intervention.

This chapter considers the opportunities for market-led investment in the DTS and explores whether the current DWGM design and market carriage model are conducive to delivering market-led investment in the DTS that is efficient and timely. It also considers the interaction between investment guided by regulatory processes, and investment that is driven by the market.

6.1 Expected private benefits to justify investment costs

As with investing in any context, a market participant considering whether to underwrite investment in additional DTS pipeline capacity will only do so if it expects to earn a return that is deemed reasonable to its investment and commensurate with the risk it faces.

The market carriage model, selected at the time of designing the DWGM, provides open access to the DTS and uses outcomes from the operation of the DWGM wholesale market to allocate pipeline capacity. This differs from the contract carriage model operating outside of the DTS, which relies on bilateral contracts between the pipeline operator and shippers to allocate pipeline capacity. One of the more fundamental differences between these two transportation arrangements is that shippers using a contract carriage pipeline can reserve firm capacity on the pipeline through bilateral contracts (that is, not open access) while market participants using the DTS cannot.

However, a market participant that enters into a long term contract with the pipeline owner (APA GasNet) to meet the cost of a pipeline expansion may receive benefits attributable to the generation of AMDQ.[77] Holders of AMDQ receive certain financial and market benefits, and some limited physical benefits. Namely:

- AMDQ provides holders with a hedge against congestion uplift charges up to Authorised Maximum Interval Quantity; and
- AMDQ entitles the holder to higher priority than customer with no AMDQ if there is a tie in injection bids or if curtailment is required to maintain system security.

77 In this chapter, 'AMDQ' is used to refer to both authorised MDQ and AMDQ credit certificates.

AMDQ does not provide firm access to capacity, and hence the same benefits, as firm capacity rights on contract carriage pipelines. This is because in the DWGM, pipeline injections and withdrawals are scheduled by AEMO on the basis of market participants' injection and withdrawal bids, rather than contractual rights. By appropriate structuring of market injection and withdrawal bids, and assignment of AMDQ to system injection and withdrawal points, these arrangements can be made to approximate firm capacity rights, but not all market risks can be eliminated or hedged (for example, surprise and common uplift charges – as outlined in section 3.2).

6.2 Ability to obtain exclusive rights to investments

There are currently two mechanisms that APA GasNet (as the DTS pipeline owner) applies following a market participant entering into a long term contract for pipeline expansion, namely:

- making the additional capacity available to the market (and therefore available on equal terms to all shippers); and
- allocating AMDQ to the contracted market participant.

However, competing market participants (who have not contracted for capacity) may be able to undercut the contracting market participant since they are only obliged to pay:

- the regulated tariff – which the contracting participant also has to pay; and
- congestion uplift – which has historically be insignificant,[78]on account of the amount of spare capacity existing in the DTS.

In addition, the contracting market participant is not compensated for usage of the capacity it funded by other market participants even if this leads to its customers being acquired by competing market participants.

The contracting market participant may therefore not have confidence that a competing market participant is not able to make use of the contracted capacity to undercut or otherwise damage its business (this is referred to as the 'free rider' effect). Parties are likely to therefore face a disincentive to engage in private contracts with APA GasNet to expand the existing DTS capacity.

We note that while there is a disincentive for market participants to engage in market-led investment in the DTS generally, this disincentive appears to have been addressed to some extent for market participants wishing to inject gas into the DTS and withdraw it at Culcairn. This is a result of the ability of shippers to obtain firm capacity rights on the Moomba to Sydney Pipeline as well as recent changes to AEMO procedures to allow those rights to be reflected in the DWGM arrangements on the other side of the Interconnect.

78 Since at least 2008 – please see section 3.2.

The AEMO revised procedures require a market participant wishing to transfer AMDQ to a withdrawal point at an interconnected pipeline or facility to provide evidence to AEMO that it holds firm capacity rights on that interconnected facility. The outcome of the procedural change is that DWGM market participants with assigned AMDQ can achieve effective firm capacity rights through the DWGM and the pipeline on the other side of the interconnection through their bidding behaviour. For example, such a market participant can bid for gas at the market price cap ($800/GJ), and match their withdrawals with DWGM injections. The procedural change is discussed further in section 7.2.

The 2014 procedural change has assisted APA GasNet in being able to undertake significant market-led investment in the northern zone of the DTS in conjunction with market participants. Specifically, APA GasNet has been able to underwrite a number of developments through contracts for additional capacity with a number of shippers, including additional compressor capacity and looping of sections of the pipeline which increased the firm export capacity at Culcairn from 46TJ to 57TJ prior to winter 2014, and to 118TJ prior to winter 2015. Further, on 24 July 2015, APA GasNet announced that it had signed a new multi-service gas transportation agreement which will support further capacity expansion of the Victoria – New South Wales Interconnect, adding another 30TJ of capacity, leading to a total export capacity at Culcairn to just under 150TJ/day, by mid-2016.[79]

There have been no other market-led investments in the DTS, outside of these recent market-led investments in the northern zone for the purposes of increasing the capacity of gas that can flow north out of the DTS to the Moomba to Sydney Pipeline.

6.3 Impact of existing regulated investment process on market-led investment

Whenever government regulators administer controls over the commercial activities of private firms, capital invested in those firms is exposed to a source of risk arising from the effects of that regulation. This risk is commonly referred to as 'regulatory risk' and its perceived degree affects the willingness of private parties to invest in regulated businesses.

The AER's treatment of demand certainty may currently be affecting the willingness of market participants to enter into contracts to privately fund pipeline expansions. Specifically, there is a general view that it is difficult to gain AER approvals for projects with uncertain demand growth. For example, AEMO has previously stated that:[80]

> "the current regulatory approval process makes it quite difficult to develop a robust case for accommodation of future growth expectations into a project given the inevitable uncertainness of demand forecast. A related

79 APA GasNet, *APA signs a new gas transportation agreement to further expand its Victoria - New South Wales Interconnect*, ASX Announcement, 24 July 2015; and APA, *APA to further expand VIC NSW interconnect*, ASX Announcement, 4 November 2013.

80 AEMO, *Transmission Capacity Issues in the DWGM*, June 2011.

example was the denial of a pre investment in easements for the completion of the Outer Ring main from Wollert to Brooklyn in the last GasNet AA [Access Arrangement]. Even though an investment of $5 million was expected to save up to $50 million in pipeline costs by pre committing the short route it was disallowed because of perceived uncertainty in the need for the pipeline."

The implication is that, where an investment proposal is driven by high or ongoing demand uncertainty, and approval of the investment through the regulatory process is likely to be difficult (for example, investments driven by gas flows north out of Victoria), potential investors may be encouraged to take on the demand forecasting risk and fund the investment themselves. As noted in section 4 above, APA GasNet has signed a number of agreements with shippers to expand the capacity of the Victoria - New South Wales Interconnect to accommodate gas flows northwards out of Victoria, which may be evidence of private parties perceiving the regulatory risk to be too high and instead opting to fund capacity themselves.[81]

Alternatively, where an investment proposal is driven by demand that is reasonably predictable (for example, general growth in gas use by residential customers and smaller industrial and commercial customers in Victoria), potential investors may have more confidence that, as demand forecasts firm up, the project will gain approval by the AER. In these instances, potential investors may be less willing to commit to funding an expansion themselves and instead rely on the regulatory process to deliver the investment. We note that there has not been any privately funded expansion of the DTS to support general demand growth in the DTS to date, which likely reflects the confidence of market participants that these investments will be approved by the AER.

6.4 Conclusions from appraisal

The market carriage model is generally considered to promote both the efficient use of the DTS (that is, through the operation of the DWGM) and aspects of dynamic efficiency (for example, because it reduces barriers to entry), as well as circumventing the need for any pipeline capacity market.

However, the market carriage model may not promote efficient and timely investment in the DTS. While some market-led investment has occurred for capacity to move gas out of the DTS, investments to relieve constraints within the system are unlikely to be market-led since expected benefits attributable to such investments are unlikely to outweigh the costs to individual market participants. Specifically, market participants cannot obtain firm access rights for the transportation of gas and therefore have little incentive to underwrite investments in the pipeline system.

81 In its draft decision for the current access arrangement applying to APA GasNet, the AER did not accept the proposed capex for the 'gas to Culcairn' project on the basis that the forecast incremental gas volumes driving the project were not arrived at on a reasonable basis, and did not represent the best forecast possible in the circumstances - AER, *Draft decision: APA GasNet access arrangement proposal for 1 January 2013 - 31 December 2017*, September 2012, Part 2, pp. 42-44.

In the absence of market-led investment, most capacity expansions in the DTS have been progressed through the regulatory process (as outlined in section 5). However, with an anticipated need to expand the network going forward to accommodate gas flowing north out of the DTS, it is therefore questionable whether it is appropriate for the risks associated with over-investment to be borne by Victorian consumers.

More generally, the issues associated with market carriage become more pronounced as capacity constraints emerge. For example, as capacity constraints emerge on a market carriage pipeline system, any inefficiencies associated with untimely regulatory-driven investment may worsen.

7 Export related issues

To maximise the efficiency of trade in gas and facilitate competition in upstream and downstream markets, shippers and producers should be able to effectively operate across different locations on the east coast without incurring substantial transaction costs.

This chapter provides an overview of the arrangements required to facilitate the transport of gas from Victoria to other jurisdictions. It examines if, and to what extent, the current DWGM arrangements could inhibit trading of gas between the DTS and interconnected facilities and pipelines. It also discusses the extent to which recent developments have addressed some of these issues.

Elements like transparent, adaptable pricing between the DWGM and interconnected pipelines, combined with ready access to available pipeline capacity, may be required to enable shippers to better manage risk and facilitate the efficient trade of gas between locations. These matters are discussed in detail in the wholesale markets and pipeline capacity workstreams of the East Coast Review.

In line with the other chapters, this chapter assumes a working knowledge of the DWGM and does not re-present existing material on how the market operates.

7.1 Barriers to exporting gas from Victoria

There are three possible routes to transport gas purchased in Victoria to markets in South Australia, NSW and QLD. An exporting party could move gas:

- to New South Wales (and Queensland) via the Eastern Gas Pipeline (the eastern route);
- to New South Wales (and Queensland) via the Interconnect (the central route); and
- to South Australia (and Queensland) via the SEA Gas Pipeline (the western route).

A summary of the various options available to market participants to export gas from Victoria to other jurisdictions is set out in Appendix B.[82]

While an exporting party seeking to move gas from Victoria to NSW or South Australia could (in theory) utilise the DWGM and the DTS to transport gas to the Eastern Gas

82 It is also possible for gas to flow from the South West Pipeline, through the DTS to New South Wales via the Culcairn Interconnect. This route and associated issues are discussed in Appendix B.4.

Pipeline (via VicHub)[83] and the SEA Gas Pipeline (via Iona), this tends not to occur. First, current physical constraints at the SEA Gas and VicHub points means that constraints are applied to restrict the amount of gas that can flow out of these points to zero. In addition, exports through the Eastern Gas Pipeline and the SEA Gas Pipeline are sourced almost exclusively from production facilities directly connected to these pipelines making the DTS, and participation in the DWGM, unnecessary. An exporting party need only negotiate for contractual gas supplies at the relevant production facility, and for pipeline capacity on the Eastern Gas Pipeline and SEA Gas Pipeline, to utilise the eastern and western routes respectively.

Gas moving through the central route must, however, move through the DTS. This would require an exporting party to register with AEMO as a participant in the DWGM and to have negotiated a transport contract with APA GasNet for pipeline capacity on the Moomba to Sydney Pipeline.

To ensure the export quantity was scheduled in the DWGM for withdrawal at the Culcairn withdrawal point, the exporting party would also need to take certain actions in the DWGM (see Appendix B.). It would also need to follow its contractual obligations in relation to nominating the export quantity to flow on the Moomba to Sydney Pipeline.

It is not apparent that there are any material barriers in terms of market arrangements preventing gas from the DTS being exported to NSW and South Australia via the eastern and western routes. However, historically, a number of concerns have been raised with regard to exports from the DTS to NSW via Culcairn. Issues that have been raised include:

- the limited physical capacity of the interconnection at Culcairn;
- the interface between the DWGM and the contract carriage arrangements on the Moomba-Sydney pipeline;
- a perception that AEMO, as system operator of the DTS, has afforded priority to Victorian customers over exports from the DTS;
- the ability of the Victorian DTS to physically support exports at Culcairn at times of high Victorian demand;
- price and uplift payment risk in the DWGM; and
- lack of firm transportation rights in the DWGM, or withdrawal rights at Culcairn, creating uncertainty for shippers, even those with firm rights on the Moomba-Sydney pipeline.

83 VicHub is an interconnect facility situated at the Longford Compressor Station and enables gas to flow bi-directionally between the Eastern Gas Pipeline and the Victorian DTS. The facility was commissioned in January 2003.

Recent developments have addressed a number of these issues, both in terms of investment in pipeline expansion in northern Victoria, and in changes to the DWGM AMDQ procedures. The key issues and recent developments are discussed in the next sections.

7.2 Alignment of interconnection capacity rights

A key issue regarding the ability to export gas north via the central route relates to the interface between the DWGM and the contract carriage regime on the Moomba to Sydney Pipeline. Specifically, the inability to align firm capacity rights across the Culcairn interconnection.

In the DWGM, users may hold AMDQ or AMDQ cc (referred to hereafter collectively as AMDQ) which, if assigned to the Culcairn withdrawal point by a market participant, provide it with scheduling priority if the interconnect is congested and withdrawal bids are equally priced.

However, historically, the DWGM procedures for assigning AMDQ at withdrawal points with interconnecting pipelines did not pay heed to contractual rights on the interconnecting pipelines.

This meant that it was possible for parties to assign AMDQ at Culcairn without having associated firm capacity on the Moomba to Sydney Pipeline. This could result in this party obtaining priority access to the Interconnect through the DWGM scheduling process, over shippers with firm capacity rights on the Moomba to Sydney Pipeline. This lack of clarity and potential inconsistencies in the allocation processes on either side of the Interconnect could give risk to an outcome where a market participant with a firm contract on the Moomba to Sydney Pipeline may not be able to move gas from Victoria.

In 2013, in consultation with APA GasNet and other stakeholders, AEMO amended the DWGM AMDQ Procedures. The amendments sought to align the assignment of AMDQ rights at points of interconnection, with contractual rights on the interconnected pipeline or facility. These amended AMDQ Procedures were approved in June 2014.[84]

As a result, a market participant wishing to transfer AMDQ to a withdrawal point at an interconnected pipeline or facility is now required to provide evidence to AEMO that it holds firm capacity rights on that interconnected facility.[85]

This change did not undermine the integrity of the market carriage approach to scheduling in accordance with market bids and offers - priority is still afforded to parties on the basis of their bid prices. However, where bid prices are tied and the

84 See "Wholesale Market AMDQ Procedures (Victoria)", approved June 2014, on the AEMO website at: http://www.aemo.com.au/Gas/Policies-and-Procedures/Declared-Wholesale-Gas-Market-Rules-and-Procedures.

85 See section 5.5 of the AMDQ Procedures.

withdrawal capacity at the interconnected facility is reached, priority is then given to those parties with AMDQ assigned at that withdrawal point. The change to the AMDQ Procedures means that only those parties with firm capacity on the interconnected facility will be able to assign AMDQ to those points. This therefore provides greater security to 'exporting' participants of the DWGM that they will be able to meet their contractual obligations outside of Victoria.

Therefore, if a market participant holding AMDQ was prepared to bid for gas at the market price cap (VoLL), and to match its withdrawals with injections into the DTS, it could effectively achieve firm capacity rights through the DTS to interconnected pipelines. This would also allow it to manage its imbalance payment exposure to the market price in the DWGM.

These amendments have been instrumental in supporting APA GasNet to undertake significant investment in the northern zone of the DTS for the purpose of increasing exports via Culcairn. Additional compressor capacity and looping of sections of the pipeline increased the firm export capacity at Culcairn from 46TJ to 57TJ for winter 2014, and to 118TJ prior to winter 2015. APA GasNet has been able to underwrite these developments through contracts for the additional capacity with a number of shippers.

In addition, on 24 July 2015, APA GasNet announced that it had signed a new multi-service gas transportation agreement which will support further capacity expansion of the Culcairn Interconnect, adding another 30TJ of capacity. This will result in a total export capacity at Culcairn to just under 150TJ/day by mid-2016.

7.3 Victorian curtailment arrangements

The Victorian arrangements for curtailment of gas usage or consumption to manage emergencies and/or preserve system security have been developed by AEMO in consultation with the Victorian Government. These arrangements are published as the Gas Load Curtailment and Gas Rationing and Recovery Guidelines on AEMO's website.[86]

These guidelines provide classifications of gas customers, and set out the priority order under which each class of gas customer will be curtailed if required to maintain system security. Where curtailment is required due to a transmission constraint, the first customers to be curtailed are those Tariff D customers[87] with either no AMDQ or that have used in excess of their assigned AMDQ. In addition, the first classification of customers to be curtailed includes:

- withdrawals into Underground Gas Storage at Iona;
- gas fired power generation scheduled by AEMO;

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

87 Tariff D customers are large customers with daily demand meters and are typically large industrial sites.

- customers who have entered into an interruptible supply contract; and
- exports via interconnections subject to alternative gas supplies being available to export gas customers in the same categories as specified by Curtailment Tables in Victoria that have not been curtailed.

While not well expressed, the last provision appears to provide for the following:

- exports to customers outside Victoria that have an alternative source of gas supply are to be curtailed ahead of their counterparts in Victoria; and
- exports to customers outside Victoria that do not have an alternative source of supply are to be curtailed in the same order as their counterparts in Victoria.[88]

These provisions and, on occasions, AEMO's inability to physically deliver required export quantities at Culcairn at times of high Victorian demand or system outages, have been perceived by some stakeholders as curtailing exports to NSW to maintain supplies to Victorian customers on a preferential basis.

The perception of discriminatory treatment in the curtailment of exports comes from the fact that AEMO will generally curtail controllable withdrawals (for example, gas powered generation and export flows) before Victorian residential or small commercial customers. This is because residential demand is not controllable and, other than broadcast directions (requests) to reduce small commercial and residential gas usage, the AEMC understands that there is no ability for AEMO to curtail such gas demand safely and effectively within required timeframes.

As a result, in the event that demand reductions are required in order to maintain system pressures and system security, the only effective and timely options are controllable withdrawals – that is, large industrial customers, gas fired generators and exports.[89]

While it is the case that AEMO has statutory obligations to maintain system security on the DTS but not elsewhere on the interconnected east coast gas system, the perception of discriminatory treatment in curtailing Victorian demand and exports may be somewhat overstated. From a system operation perspective, the curtailment arrangements appear appropriate. If there is a need to reduce demand to maintain system pressures and system security, the only effective and timely option available is controllable withdrawal - that is, large industrial load, gas-fired generation and export flows.

That said, we understand that the curtailment arrangement may discourage market participants that have access to alternative sources of supply from transporting gas

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

89 Even in the case of large industrial customers and gas fired generators, AEMO would not itself be able to turn these off physically, but would rely on responses to scheduling instructions or directions, with no guarantee of a timely response.

through the DWGM, even if that is the optimal export route. This may occur if market participants perceive there is a risk that all exports will be treated as curtailable, irrespective of whether or not they have an alternative source of supply. However, without evidence of this behaviour having actually occurred, it is difficult to form a view on the extent to which this could present a material barrier to exports. .

It is also important to note that AEMO's Victorian Gas Load Curtailment and Gas Rationing and Recovery Guidelines is publicly available.[90] The information included in this guideline provides market participants and other stakeholders with a better idea about the likelihood they will be curtailed, allow them to choose how to manage the risk (for example, through insurance) and enable them to put in place the necessary arrangements before Victoria exercises its emergency powers.

7.4 Other issues and developments

7.4.1 Erosion of capacity at Culcairn

An issue raised previously in relation to export capacity at Culcairn is that demand growth in Victoria can, over time, erode the ability of the DTS to consistently deliver previous levels of export capacity at Culcairn. The concern comes from the fact that changes in demand in one part of the DTS can affect capacity elsewhere in the DTS. Therefore, if demand on the DTS increases substantially in the future, this may lead to a situation where either less gas is available for export, or the DTS capacity has to be expanded to maintain contracted AMDQ capacity at Culcairn.

The AEMC notes that projected demand growth is such that this is not expected to be an issue in the near future. In addition, the current regulatory processes for pipeline investment should be capable of handling this issue should it arise in future.

7.4.2 Price and uplift payment risk

As noted above, a market participant seeking certainty that its gas will flow from the DTS via Culcairn and into NSW (in a way that minimises exposure to market price outcomes) needs to have in place certain arrangements, and to take certain actions which include: contracting for gas supplies; obtaining and assigning AMDQ to Culcairn; and adopting an appropriately priced bidding strategy for gas injections and withdrawals. On the north side of Culcairn, the market participants also need to have a contract on the Moomba to Sydney Pipeline, and follow the nominations process that applies on that pipeline.

An additional concern that has been raised is that, while a market participant seeking to export gas via the Interconnect can largely protect itself from exposure to imbalance payments, it is still exposed to the risk of potentially unpredictable deviation payments (for example, in the event of unplanned plant outages affecting their injections or withdrawals from the DTS) and uplift payments.

90 See AEMO's website: www.aemo.com

However, there are costs that the market incurs to support the flow of exports through the DTS (for example, additional compressor operation and ancillary payments). On this basis it could be argued that these costs are appropriate, although not always easy to predict or hedge entirely. This issue is discussed further in Chapter 3.

7.5 Conclusions from appraisal

Generally, there appear to be no material barriers to exporting gas from Victoria. Appendix B presents illustrations of gas flows through the Interconnect, and on the Eastern Gas Pipeline and SEA Gas Pipeline over the past five years, showing that the pipelines are all well utilised for exports from Victoria.

While the interface at Culcairn between the DWGM and the Moomba to Sydney pipeline is not entirely seamless, there have been significant improvements made recently, and these are expected to have lasting effect.

It may be possible that greater alignment of capacity and trading arrangements could be achieved between the Victorian DWGM and DTS and the arrangements on the Moomba to Sydney Pipeline. For example, the concepts of “firm capacity” are not identical on both pipelines. In the DWGM, market participants with AMDQ assigned at Culcairn still face some potential risk exposure due to imbalances, deviations and uplift payments, in addition to the known pipeline transportation tariffs. However, it is not clear that these issues are capable of being addressed without fundamental change to the DWGM arrangements.

8 Possible policy response

To continue to progress the debate on gas market development, and to provide stakeholders with the opportunity to provide more focussed feedback leading into the Commission's DWGM Review draft report, five high level packages for reform have been developed. These packages have been developed to combine elements for reform that aim to resolve the issues identified in chapters 3 - 7.

The five packages do not represent a preferred option and have been put together as a way of seeking feedback from stakeholders. While they have been prepared having regard to the terms of reference for the DWGM Review and the Energy Council's Vision, they have not yet been tested against the assessment framework developed as part of the wider East Coast Review, and reproduced as Appendix E.

The five packages represent a range from incremental development to more pronounced changes to the current gas market arrangements In Victoria. The packages therefore reflect changes of varying magnitudes to the status quo.

In addition, each package assembled and discussed below is each consistent with one of the three concepts established as part of the AEMC Wholesale Gas Markets Discussion Paper, published on 6 August 2015 as part of the East Coast Wholesale Gas Markets and Pipeline Frameworks Review (the 'Wholesale Gas Markets Discussion Paper'). A discussion of how each package relates to these broader east coast concepts is provided in the sections below.

Further, in assessing any, or all, of these packages against the assessment framework (set out in Appendix E), we will explicitly consider the feasibility of replicating these designs in a ‘northern’ market, consistent with the concepts set out in the Wholesale Gas Markets Discussion Paper. The Commission considers the simplification and consolidation of market designs operating on the east coast to be an important aspect of reducing transaction costs in order to encourage greater trading and participation, with a view to achieving the COAG Energy Council Vision.

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

The five high level packages for reform are illustrated in the figure below.

Figure 8.1 Overview of packages for reform

<table>
<tr><th>Market improvements</th><th colspan="2">Market development</th><th colspan="2">Market reform</th></tr>
<tr><th>Package A
Targeted measures</th><th>Package B
Transmission rights</th><th>Package C
Capacity rights</th><th>Package D
Entry/Exit model</th><th>Package E
Hub & Spoke model</th></tr>
<tr><td>Targeted transmission rights</td><td>Simplified pricing mechanism</td><td rowspan="4">Zone-based pricing and capacity rights</td><td rowspan="4">Entry/Exit model</td><td rowspan="4">GSHs at Longford and Iona and balancing in Melbourne</td></tr>
<tr><td>Trading of AMDQ rights</td><td rowspan="3">Transmission rights</td></tr>
<tr><td>Clearer AMDQ allocation process</td></tr>
<tr><td>Review planning standard</td></tr>
</table>

Source: AEMC.

8.1 Package A: Targeted measures

Package A includes a number of measures that could be progressed over the short to medium term to assist the Victorian market and regulatory arrangements to better achieve the NGO.

The key objectives of this package would be to provide increased opportunities for market participants to better manage short term risk exposure, address the free-rider problem for new investments and strengthen existing market signals for investment by reducing uncertainty around the allocation process for AMDQ cc.

There would be no explicit mechanisms to deliver an efficient reference price meaning this package would be unlikely to contribute directly to the development of new financial risk management products. It would however include an efficient, flexible and timely mechanism to allow participants to better manage their short term risk exposure and optimise their portfolios.

Aspects of this package would also be relatively easy to implement compared to the other packages. However, it may still potentially involve significant rule changes and changes to APA's access arrangement. While it would retain the existing AMDQ and AMDQ cc arrangements, it would require some changes to the processes and systems for managing those arrangements.

The rationale for this package would be to fix 'known issues' whilst retaining the principles of the current market design, and thus minimise disturbance to current activities in the market. While it seeks to promote efficient use of, and investment in, the DTS, it may not be fully effective in moving the Victorian DWGM towards the Energy Council's Vision and Gas Market Development Plan.

Package A retains a virtual hub definition across the DTS where parties can trade gas and so is consistent with concept 2 established as part of the Wholesale Gas Markets

Discussion Paper. Concept 2 involves a virtual hub covering the DTS aimed at developing a 'southern' reference price for gas on the east coast.

8.1.1 Targeted Transmission Rights

This measure is intended to provide a limited and targeted means of improving incentives for market-based investment in pipeline capacity expansions. It would involve establishing a usage charge (called an "expanded asset charge") that would apply to market participants that use an asset which has been privately funded by another market participant (the 'foundation market participant')[91], and refunding or rebating the revenue collected from this charge to the foundation market participant as compensation.

While potentially complex to implement, this arrangement could provide a flexible level of protection against free riding to the foundation market participant: the more that others use the contracted capacity that the foundation market participant has funded, the more revenue would be received thereby by lowering the net cost of its investment.

The improved incentives would only be relevant to future expansions of the DTS.

Specifically, the mechanism would entail:

- a new right for subsequent market participants to use spare capacity on the expanded pipeline;
- an obligation on those participants to pay the expanded asset charge; and
- a right for the foundation market participant (rather than the asset owner) to receive the revenues from that charge (which will offset their foundation contract charges).

Key to the success of this proposal would be the development of the usage and allocation rules. The mechanism would require:

- usage rules that were capable of attributing usage to all (or some) market participants and the foundation market participant that "use" both the existing and expanded asset on a reasonable basis; and
- charge allocation rules that charge subsequent market participants' usage including:
  - firstly at the relevant approved transmission tariff; and
  - where the threshold for use of the existing tariffed transmission service is exceeded, at the "expanded asset charge rate".

91 A market participant which enters into a long term contract with the pipeline owner to meet the cost of a pipeline expansion

The concept of an expanded asset charge may not fit easily with the current market carriage framework and, as such, development of the usage and allocation rules would require careful consideration. Nevertheless, while potentially complex, a flexible and interactive approach to developing a charge set at the right level may be worth exploring further.[92]

One approach to implementation of the targeted transmission rights proposal could centre on the AER developing a regulatory process (for example, via a guideline) outlining the key steps. These may include the following:

- The foundation market participant(s) would negotiate with APA on draft pricing and contracts for a pipeline expansion.
- APA (following principles set out in the AER guideline) would publish draft usage charges and details applying to other market participants that use the relevant contracted asset.
- Based on this published information, other market participants would be provided an opportunity to become a foundation market participant.
- If other market participants did choose to become a foundation market participant, then the funding structures and charges may need to be amended and republished.
- This process would continue until there are no further foundation market participants.
- Once negotiations were complete:
  - AER approval would be sought to set the usage charges.
  - Foundation market participants and APA would finalise contracts.
  - Foundation market participants would be allocated AMDQ / AMDQ credits as currently occurs.

To ensure that other market participants (including small market participants) are not adversely affected by the setting of the charges, AER approval would be a feature.

As noted above, the ability of this option to promote market incentives for investment depends on whether usage charges for non-firm service and compensation paid to foundation market participants could be set at a level that encourages parties to enter into contracts to fund efficient expansions and on the ability to determine/allocate usage of pre-existing ("commonly funded") and privately funded pipeline system assets.

The option involves no changes to the current market design but would likely involve changes to the DTS Access Arrangement. These changes would likely be much less

92 This is particularly the case because negotiation of the charge would be relevant to a new asset.

complicated to implement than those for the Transmission Rights proposal included in Package B, because they would only apply to specific new investment proposals.

In terms of the legal and regulatory framework, this option may involve changes to the NGR and possibly the National Gas Law (NGL), to ensure that each stakeholder has the necessary rights and obligations under the new arrangements, and that there is a suitable process to enable prices to be agreed (and disputes resolved) outside of an access arrangement review. Current provisions dealing with connection to the DTS may require amendment.

This option only addresses the free riding concern. It does not address other possible concerns for market participants entering into contracts for expansions, such as financial risk (that is, exposure to risk of ancillary payments) and lack of physical certainty (that is, confidence that the market participants will under all circumstances be able inject gas at one end of the new capacity and withdraw at the other end).

8.1.2 AMDQ and AMDQ cc trading mechanism

In 2013-14, the AEMC considered a rule change request submitted by AEMO seeking to introduce a mechanism that would enable market participants to transfer all or part of their portfolio of financial benefits associated with holding AMDQ and AMDQ cc to other market participants operating in the DWGM.[93] Due to circumstances at the time (namely revised costs and timeframes for implementation) the Commission decided not to make a rule in its final determination.[94] A summary of the rule change process is included in Appendix D.

Nevertheless, AEMC considers the concept has strong merit and, in the event Package A was progressed in lieu of more fundamental reforms to the DWGM, considers this proposal could offer substantial benefits to market participants in terms of managing their short term risk exposure.

This mechanism is therefore consistent with the Portfolio Rights Trading mechanism developed by AEMO and submitted to the AEMC as a rule change request in 2013.

The introduction of this measure is intended to provide an efficient, flexible and timely mechanism that would allow market participants to better manage their short term risk exposure and optimise their portfolios.

This measure would enable market participants to transfer all or part of their portfolio of financial benefits associated with holding AMDQ and AMDQ cc to other market participants operating in the DWGM (the holder of the AMDQ and AMDQ cc would remain unchanged). It is anticipated that this, in turn, would encourage more efficient utilisation of the Victorian DTS. This is on the basis that if market participants are able to access the benefits of AMDQ and AMDQ cc, then they may be more willing to utilise existing pipelines.

---

93 See: http://www.aemc.gov.au/Rule-Changes/Portfolio-Rights-Trading

94 AEMC 2014, *Portfolio Rights Trading, Rule Determination*, 27 November 2014 , Sydney.

In summary, the mechanism would require AEMO to:

- transfer the entitlement to the benefits associated with AMDQ and AMDQ cc between market participants;
- adjust trading market participants' AMDQ and AMDQ cc allocations in line with information submitted from the trades (the adjusted figures must then be used to calculate injection tie-breaking rights); and
- develop and publish procedures to implement the trading mechanism.

The trading mechanism would not include contract terms and payments. Financial transactions related to the transfer of the financial rights of AMDQ and AMDQ cc would take place through bilateral contracts between the trading parties outside of the NGR. Importantly, physical ownership of AMDQ and AMDQ cc and any curtailment rights would remain unchanged under this proposal.

The amendments proposed to Part 19 of the NGR include a number of changes to existing definitions and rules as well as the inclusion of a number of new definitions and rules.

By facilitating access to unused pipeline capacity, this mechanism may increase competition between market participants. It would do so by broadening the tools available for portfolio management, lowering barriers to entry for new market participants (including new retailers) and enhancing participation by end users in the DWGM. Increasing competitive pressure could ultimately result in lower prices to gas consumers.

In addition, by introducing well-functioning and flexible pipeline trading arrangements, the trading mechanism may lower transaction costs for market participants seeking access to short-term pipeline services. In addition, by generating interest between buyers and sellers, the mechanism may improve pipeline capacity trading liquidity.

Finally, by encouraging the reallocation of unused pipeline capacity between market participants, the mechanism should encourage more efficient use of existing infrastructure, and should contribute to the pipeline being expanded only when it is efficient to do so.

8.1.3 AMDQ and AMDQ cc allocation processes

The discussion in section 4.4 highlighted a lack of certainty and clarity in respect of the process allocating AMDQ cc, and the interaction between AMDQ cc and APA’s access arrangement for the DTS. Clarification of the allocation arrangements, including the mechanism to determine price, should improve users’ understanding of AMDQ cc and could improve existing signals for investment in the DTS, and in doing so promote efficient investment in and use of the DTS.

The process for allocating AMDQ cc is not specified in the NGR, the current access arrangement for the DTS, or by AEMO. This differs from the AMDQ allocation process which is carried out by AEMO and specified in a procedure as provided for by the rules. We consider there is merit in exploring whether increased transparency around the allocation process, and a more consistent approach to the allocation of AMDQ and AMDQ cc, would increase certainty for users and allow them to make better informed decisions regarding their activities (including their risk management options) in the DWGM. Possible ways this could be achieved include by:

- including the allocation process for AMDQ cc in the rules, consistent with approach for the AMDQ allocation process;
- requiring APA to include in its next access arrangement the process it intends to follow in allocating AMDQ cc; or
- requiring APA to develop and make publicly available a policy statement setting out the process it intends to follow in allocating AMDQ cc.

In addition, we consider that current signals for investment could be strengthened considerably by requiring that the allocation process for AMDQ cc be undertaken prior to, rather than after, pipeline capacity expansions or extensions have occurred.[95] This would allow the demand for AMDQ cc to inform, rather than follow, investment decisions, thereby promoting efficient and timely investment. Further, allocating AMDQ cc through a market-determined process (for example, a tender process or open auction) would support the discovery of a price for AMDQ cc which reflects demand and supply. A market-based approach to determining price would be expected to strengthen the signal further.

In line with the publication of this discussion paper, the Commission has commenced consultation on the DWGM AMDQ allocation rule change request proposed by AEMO.[96] The consultation paper for the rule change request was published on 10 September 2015.

The rule change request aims to address gaps and inconsistencies in the allocation of AMDQ and AMDQ cc that have arisen due to inconsistent redrafting of the relevant provisions over time.[97] Specifically, it seeks to amend the NGR to specify that all new capacity created on the DTS will create AMDQ cc and that AMDQ relates only to capacity in existence as of 15 March 1999.

In addition, there are several consequential amendments resulting from the clarifications, including the requirement for both AEMO and APA to provide a

95 Pre-commitment to bidding and obtaining AMDQ cc would be similar to the way in which efficient capacity expansions are determined under the contract carriage model.

96 AEMC, *DWGM - AMDQ allocation Consultation Paper*, 10 September 2015 , Sydney.

97 AEMO indicates that the current rules as set out in the NGR have a complex structure that hinders interpretation and that the rules provide no basis for determining the classification of the rights associated with new capacity on the system. The rule change request is available on the AEMC's website.

minimum of twenty business days' notice prior to allocating the available AMDQ or AMDQ cc. Further, there is a specific requirement for AEMO to use any proceeds from the auctions of AMDQ to offset the operating costs for the Victorian gas market.

As part of its assessment of the rule change request, the AEMC has indicated its intention to consider (among other things) the effectiveness of the current AMDQ cc allocation process. Specifically, it will consider whether increased certainty in the process used to allocated AMDQ cc, and in the use of proceeds from the auction/tender process, would promote efficient investment in and use of the system.[98]

These issues are inextricably linked to the issue of market signals and incentives for investment in the DTS – a key theme of this review.[99] Given the interaction between the rule change request and this review, we have attempted to align the publication dates for the consultation paper and draft determination for the rule change request, with the publication of papers for the DWGM review.

This will allow us to ensure consistency where possible and appropriate. It also provides the opportunity for any issues which relate to the AMDQ cc allocation process which are not be captured in (or not within scope of) the rule change request to subsequently be incorporated into further development of Package A, in the instance this package is pursued.

8.1.4 DTS planning standard

There is no statutory planning standard for the DTS in Victoria. However, the 1 in 20 planning and system security standard used by AEMO was "inherited" from the pre-privatisation, pre-spot market, Victorian Gas and Fuel Corporation standard and is consistent with system security standards in use in some international gas systems, including the UK. As noted in section 4.6, APA and AEMO take a different approach to determining pipeline capacity for the DTS. Specifically, APA GasNet considers the way in which AEMO applies the 1 in 20 planning standard is overly conservative in assessing the additional capacity provided by pipeline expansions.

On the basis that this issue has the potential to impact investment in the DTS, and on operation of the market, we consider there is merit in considering further the appropriateness of the continued use of a 1 in 20 planning standard for the DTS.

---

98 The AEMC also intends to consider whether greater certainty in relation to the classification of new capacity as AMDQ cc would promote efficient investment, and whether mandatory minimum notice provisions would assist market participants in making more informed and efficient decisions. See: AEMC, *DWGM - AMDQ allocation Consultation Paper*, 10 September 2015.

99 Unless the review leads to the removal of AMDQ and AMDQ cc, the need for the rule change would remain. Further, given the overall timing for the review to be completed and any recommendations being implemented, even if a wholesale change of the market design was implemented, clarification for the classification of new capacity created by extensions or expansions would be beneficial.

The purpose of the review would be to remove uncertainty and provide greater clarity and understanding around the approach to determining pipeline capacity in the DTS. As part of this review, alternatives to the “1 in X” standard could also be considered (for example, a net benefits test using some value of customer reliability).

In the event this Package A was considered for further development, there would be merit in carrying out this review ahead of APA’s next access arrangement submission (due in December 2016). An outcome of such a review may be an agreed standard against which to assess proposed system augmentation projects for inclusion in APA GasNet’s capital base.

8.2 Package B: Simplified DWGM pricing mechanism and transmission rights

Package B has been developed to remove the current ancillary payment mechanism operating in the DWGM and the associated unmanageable price risks that market participants currently face. It is considered that these changes will encourage the development of financial products that participants can use to hedge their exposure to prices in the DWGM.

Package B also involves replacing the limited capacity rights provided by AMDQ currently with a set of firm and non-firm transmission rights. The installation of more tangible transmission rights is expected to resolve the current lack of market-led investment in the DTS by providing private funders of this investment with firm transmission rights.

Package B retains a virtual hub definition across the DTS where parties can trade gas and so is consistent with concept 2 established as part of the Wholesale Gas Markets Discussion Paper. Concept 2 involves a virtual hub covering the DTS aimed at developing a 'southern' reference price for gas on the east coast.

The simplified pricing mechanism and system of transmission rights are outlined in the sections below.

8.2.1 Simplified pricing mechanism

Package B involves adopting a simplified pricing mechanism for the DWGM that moves away from having separate pricing and operating schedules. Specifically, this package involves having a single schedule that optimises bids and offers subject to *all* transmission pipeline constraints (for example, similar to the current operating schedule), and adopts the highest priced injection or withdrawal that is scheduled as the market clearing price for the entire DWGM. The intention of this mechanism is to simplify and increase the transparency of market prices, and internalise the current ancillary payments in the market price.

An implication of having only one schedule is that prices for the entire DWGM will likely be set with reference to bids and offers that can relieve/affect any prevailing constraints in the DTS at that time. This will likely constrain the effective liquidity to the market participants that can bid and offer to relieve that constraint and may result in higher and more volatile market prices than have been observed historically.

While market prices may become higher and more volatile than currently, it is likely that the risk profile of market participants will be improved significantly, ie, participants will face risks that are able to be hedged. Specifically, the move to a 'cleaner' market price that internalises the costs currently associated with ancillary payments should support the development of complementary financial products that allow DWGM participants to hedge their exposure to price risk.

A further implication of having DWGM prices set with reference to one schedule is that it socialises the cost of constraints and moves away from an attempt to allocate the cost of these constraints to the causer(s). However, as noted above, the increased manageability of risk for market participants may offset the loss of the limited benefits derived from the current arrangements, which only partially achieves cost causation allocation. In addition, Package C (outlined below) has been included, in part, to investigate a pricing mechanism that limits the exposure of market participants to constraint-derived price risk to the DTS zone(s) in which they operate.

We recognise that it would be difficult to investigate this simplified pricing mechanism in isolation since there is a recognised link, albeit weak, between ancillary payments, uplift hedges, and market signals for investment in pipeline expansion (as discussed in section 4.3 above). The question of removing or changing the ancillary payment and uplift allocation mechanisms are inextricably linked to the issue of pipeline investment signals and mechanisms in the DTS. The simplified pricing mechanism included in this package has therefore been coupled with a revised set of transmission rights, as outlined below.

At this stage we have not sought to undertake any detailed analysis to assess likely changes in bidding behaviours and market outcomes should this mechanism be adopted.

8.2.2 Transmission rights on the DTS

Package B involves translating the existing AMDQ and AMDQ cc mechanisms into a transmission right by introducing different tariffing arrangements for use of the DTS. The intention is to provide market participants the opportunity to pay for firm transmission rights and thereby encourage market-led investment in the DTS. We note that a model for transmission rights was developed in detail as part of the Pricing and Balancing Review undertaken by VENCorp during 2003 and 2004.[100]

Under this package market participants can contract with APA for the majority of their flows as firm transportation services. Capacity rights and transmission charges would be allocated under these contracts for these services. The transportation contracts are

---

100 Specifically, Stage 2 of the Pricing and Balancing Review recommendations focussed on transmission rights, see: VENCorp, *Victorian Gas Market Pricing and Balancing Review – Recommendations to Government*, 30 June 2004.

intended to provide a more financially firm transmission charging regime than under the existing market arrangements. Firm services would determine the transmission charges payable by market participants and provide limited protection from congestion uplift and curtailments of withdrawals.

Should a market participant choose not to contract for firm services, they would be required as a condition of connection to enter into a service agreement with APA to cover their gas flows as non-firm, that is, flows not covered by reserved Maximum Daily Quantity under firm service transportation contracts.

We understand that the model developed by VENCorp as part of the Pricing and Balancing Review involved market participants being offered a range of firm and non-firm services and being tariffed accordingly. Specifically, we understand that market participants would be able to procure firm 'hub services' (for withdrawals at the hub or along the injection route), 'lateral services' (for withdrawals within defined withdrawal zones) and 'LNG services' (providing LNG capacity rights to holders of LNG storage capacity for injection from LNG storage), as well as limited firm 'backhaul services' (for withdrawals at the defined withdrawal offtake) and 'summer services' (summer capacity rights for flows from the hub to Port Campbell).

As noted above, implementing these transmission rights essentially involves reforming the existing tariff arrangements of APA. The regulated tariffs of APA are currently structured in two parts:

- location specific capacity-based charges for gas entry to and exit from the gas transmission system; and
- location dependent flat volumetric energy charges to recover the remaining regulatory approved allowable transmission revenues.

To implement a system of transmission rights, the volumetric charges would likely need to be displaced in part by capacity-based charges and longer term contracts.

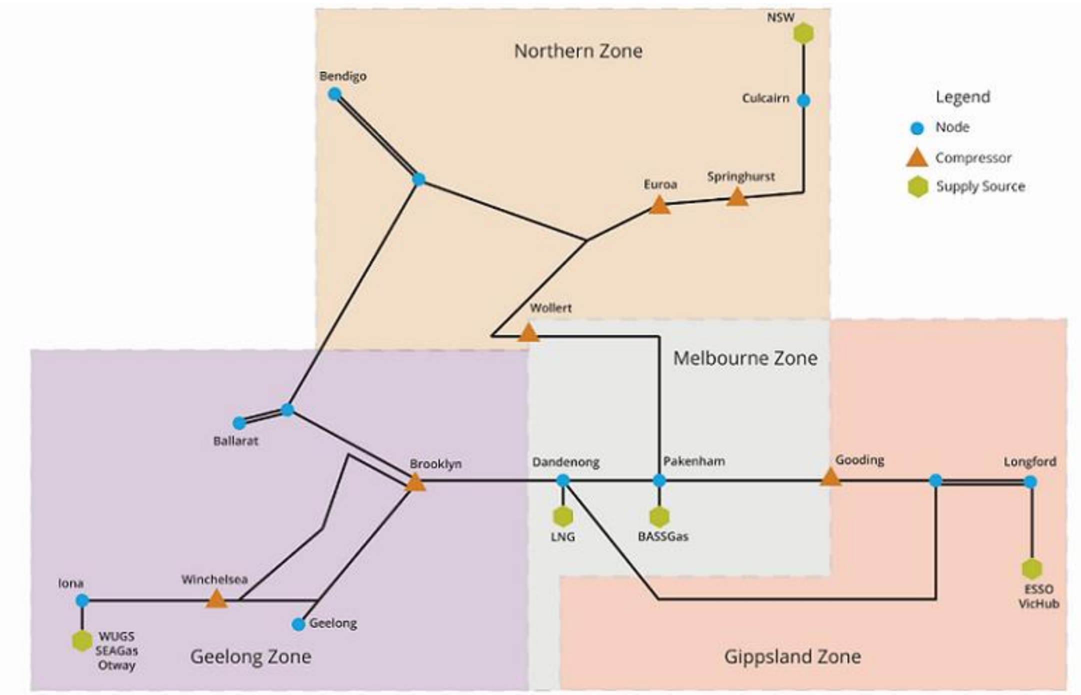
It is expected that revising the tariff structure in this manner will address participants requirements for competitive certainty by preventing free-rider use of spare capacity, as well as providing APA with greater revenue certainty. However, any rebalancing of transmission tariffs will create winners and losers and so the effects on various parties needs to be carefully assessed.

Any investment-signalling benefit associated with this package depends on being able to set overrun charges for non-firm services (ie, for pipeline usage by users outside of their capacity rights) at an appropriate level, which in the DTS is likely to be a difficult task. Specifically, any overrun tariff will need to be sufficiently high to provide incentives to invest in new pipeline capacity but not so high as to make any use of spare pipeline capacity prohibitively expensive. Since the value of spare pipeline capacity on the DTS will vary with supply and demand conditions, as well as across different locations of the DTS, the setting of this tariff at an appropriate level is likely to be problematic and may undermine this package's ability to support long-term market investment.

8.3 Package C: Zone-based pricing and capacity rights

Package C involves establishing a number of different pricing zones across the DTS. In the Pricing and Balancing Review, VENCorp recommended an option including four or five zones. For the purposes of illustrating the option, this paper assumes that four zones would be established: the Northern zone; the Melbourne zone; the Gippsland zone; and the Geelong zone.[101] These four zones are illustrated in the figure below.[102]

Figure 8.2 The four assumed DTS zones



Source: AEMC, derived from the AEMO Victorian Gas Transmission Network - Topological Representation, available at: http://www.aemo.com.au/Maps-and-Multimedia

The intention of establishing multiple pricing zones is to generate prices across the DTS that better signal where constraints occur than under either the current arrangements and the arrangements included in Package B. When combined with the introduction of capacity rights between the zones, this would provide a market determined price for usage of the system by users without such rights, and therefore a signal for investment.

While this package aims to provide locational signals across the DTS by zone, a separate package of full nodal pricing has not been assessed. We understand that there are conceptual and technical difficulties associated with nodal pricing in gas networks

---

101 These are largely consistent with the existing Market Clearing Engine assumed network topology configuration. However, given its small size, and the absence of a supply source within it, the existing Ballarat zone has been subsumed into the Geelong Zone. See: AEMO, *An Overview of the Vic Gas Market (DWGM), Workshop Material*, workshop given 23 January 2013 at the AEMC offices, p. 2-10.

102 These zones have been constructed solely to demonstrate how this package could operate. The boundaries of these zones may not necessarily be where congestion is and if this package is to be pursued further consideration of where zonal boundaries lie is essential.

making it a highly costly and very risky package to implement.[103] We are therefore interested in the view to stakeholders as to whether zonal pricing can provide effective locational signals within the DTS while being practical, and cost effective, to implement.

Package C is consistent with concept 2 established as part of the Wholesale Gas Markets Discussion Paper, that is, the establishment of a virtual hub covering the DTS aimed at developing a 'southern' reference price for gas on the east coast. However, whenever there are constraints on the DTS, there may be up to four different zonal prices within this virtual hub under Package C. This system of zonal pricing is outlined in detail below.

8.3.1 Zone-based pricing

Package C includes the same simplified pricing mechanism as Package B. However, this mechanism is applied separately to each of the four zones defined in this package and the result is that there would be four observed wholesale gas prices in Victoria.

In practice, observed prices would be expected to:

- be equal across the four zones when there are no constraints within the DTS; and
- diverge during times of constraint.

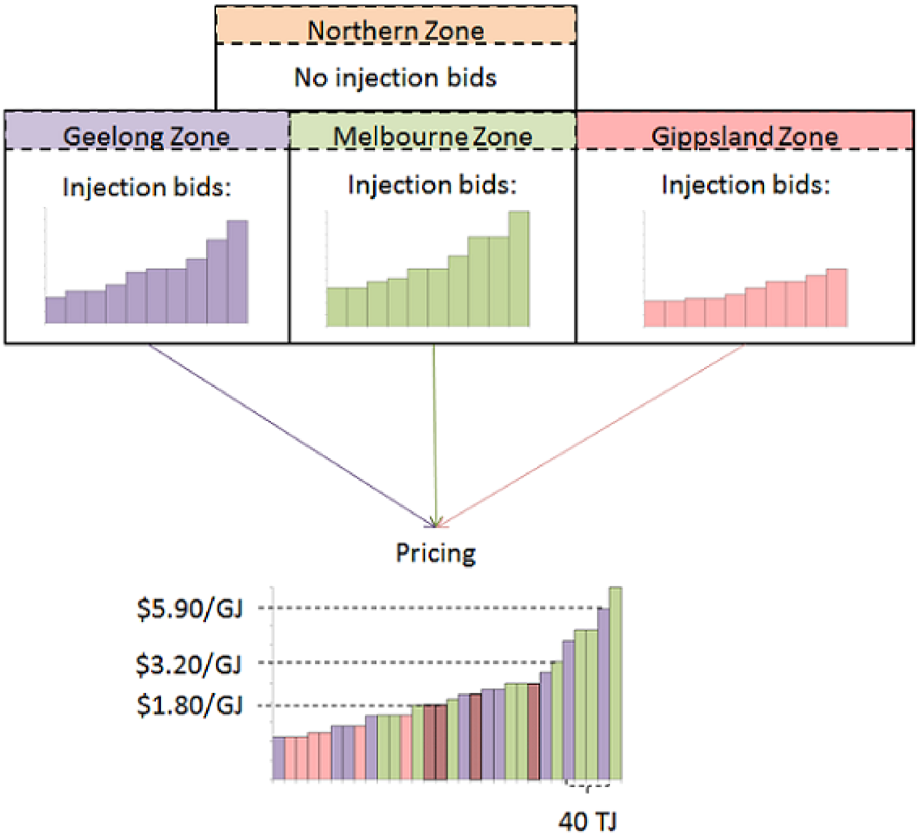
To outline this we have constructed a simple stylised example, as illustrated in the figure below. If there are no constraints in the DTS then the marginal offer across the entire DTS is used to set the price in each of the four zones, which in the example below results in a price of $3.20/GJ.

However, if there is a constraint between two of the zones then prices in each zone can only be set with reference to the physical gas actually available to each zone and prices across zones will diverge.

The example below assumes that there is a constraint on the Longford to Melbourne pipeline that results in 40TJ of within-merit gas not being available from Longford. The unavailable gas on account of this constraint (shown by red and grey striped bars) means that more expensive gas needs to be called upon in the other three zones and hence the price increases in these zones. In this simplified example, the price in the Gippsland zone is $1.80/GJ (representing the marginally priced gas in that zone), while the price in the other four zones is $5.90/GJ.

103 For example, we understand that nodal pricing in the DTS can include complex pricing situations where gas must flow from one node to another but the gas is valued more at the original node. This is driven by the pressure/flow relationships that govern the flow of gas in the pipeline system – the gas will flow from high pressure to low pressure unless limited by a pressure or flow regulator or a check valve. At the time of undertaking the Pricing and Balancing Review, the conceptual and technical issues were stated to be considerable and will require additional costs to mitigate and create implementation risk for the market. See: ICF, *Stage 2-Evaluation Of Market Design Packages Detailed Report (Final)*, 14 April 2004 pp. 16 & 64

Figure 8.3 Divergence of zonal prices during constraints



Source: AEMC. Note: it has been assumed that all injection bids are for the same quantity and that the Northern Zone is only used for withdrawals during the period of interest.

While this simple example focuses on the effects of one constraint in isolation, and the resultant divergence in price between one zone and the other three zones, in practice, many constraints may affect the market simultaneously and create different prices in multiple, or all, zones at the same time.

Importantly, the divergence of zonal prices provides signals for investment. In the example above, the observed price difference between the Gippsland zone price and the rest of the DTS provides a signal that, if sustained, should result in investment to build out the constraint so that the lower priced Gippsland gas can be sold into the other higher priced regions.[104]

8.3.2 Capacity rights and network investment

Package C also introduces capacity rights, a form of financial transmission right. It is these rights which represent the mechanism through which inter-zonal investment would be expected to be triggered.

104 The divergence in prices would create a settlement surplus which would also need to be dispersed.

At times of price divergence, holders of the rights receive payments equivalent to the difference in the zonal prices multiplied by the volume of the rights held.[105] The rights therefore provide a means to participants of hedging the different zonal prices associated with their injections and withdrawals.

The rights would be backed by physical network capacity, and demand from participants for additional rights would prompt the network owner to invest in additional inter-zonal capacity. This mechanism is very similar to the Optional Firm Access (OFA) model considered by the Commission in the National Electricity Market.

As in OFA, participation in the market and use of the system by parties without firm capacity rights would be permitted, but these participants would be exposed to the divergence in prices that would result from congestion. Participants weighing these costs against the costs associated with procuring firm rights would provide a market driven approach to network investment.

The processes for procuring and pricing capacity rights would represent important elements of the model, and would require detailed consideration. Where new rights were sold, the pipeline owner would receive additional revenue to fund the costs of the resulting investment.

As the capacity rights relate only to inter-zonal congestion, the market-led signals would only drive investment between zones – a separate process would be required to govern investment within zones. The most likely approach would appear to be retention of the existing regulatory process.

In the Pricing and Balancing Review, VENCorp envisaged that the firm capacity rights associated with a zonal pricing model could be traded through a market which integrates energy and capacity pricing.

The concept of these biddable capacity rights was to enable the holders of firm rights to offer their unused capacity to the market at a specified price, against which other users could bid for that capacity. This would enable a market-based price to be set, that firm users would receive for usage of their spare capacity by other, non-firm, pipeline users on a day to day basis.

The practicality and usefulness of this mechanism would need to be examined as part of the wider process of developing the model, which would be a significant exercise. In particular, consideration would need to be given to the calculation of zonal prices, the definition, issuance and pricing of the rights, and the impacts on the investment process.

105 These payments are conceptually similar to inter-regional settlement residues in the National Electricity Market.

8.4 Package D: Entry-exit model

Package D involves converting the existing market carriage arrangements applying to the DTS to an entry-exit model.

An entry-exit system is a gas network access model that allows network users to secure capacity rights independently at entry and exit points. Market participants therefore need to neither specify a specific transmission path nor distance, but merely the network points they intend to use for entry and exit into/out of the system.

The system of entry-exit rights would be coupled with a virtual hub covering the entire DTS. A virtual trading point ensures that the entry and exit points are independent of one other, as market participants are allowed to transfer gas at this virtual point. For example, a participant that has contracted entry capacity could sell gas at the virtual trading point, which could be purchased by a participant who has contracted exit capacity.

While the DWGM is currently a virtual hub allowing the transfer of gas, it also implicitly allocates capacity on the DTS through the trading of wholesale gas. The DWGM would therefore need to be redesigned to solely involve the trading of gas, that is, to remove the implicit allocation of DTS capacity.

An entry-exit model has been included as a package it is considered to:

- promote competition – encompasses low barriers to entry for new players on the market;
- support gas trading and the development of a meaningful reference price – gas is traded independently of its physical flow or location; and
- result in cost reflective capacity prices for the DTS.

This package is consistent with concept 2 established as part of the Wholesale Gas Markets Discussion Paper. Package D draws on gas market design widely adopted in Europe and aims to develop a 'southern' reference price for gas on the east coast.

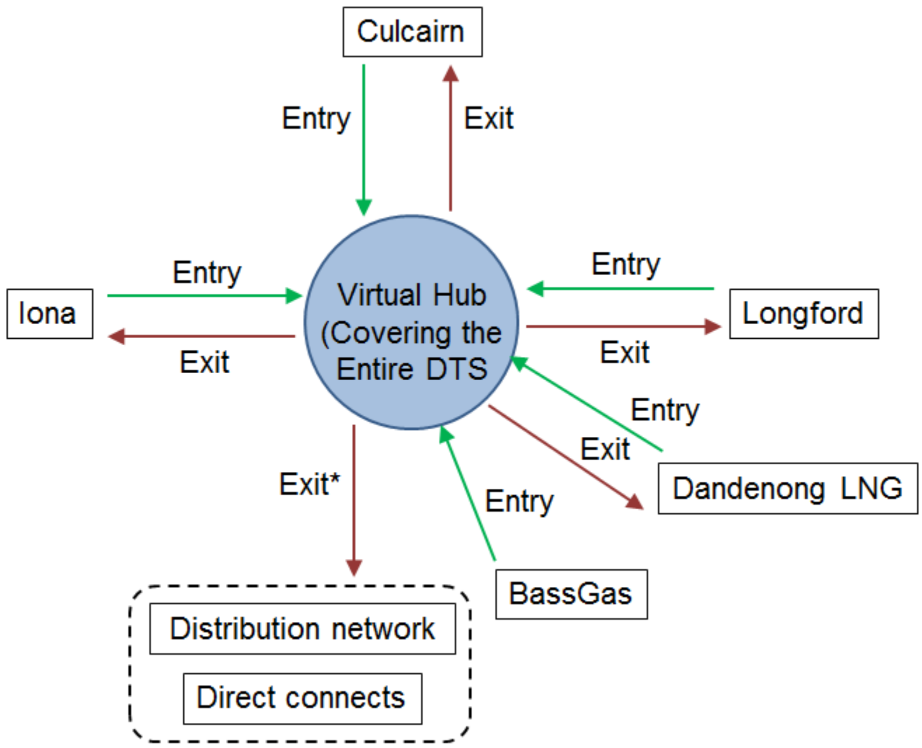
An overview of both the entry-exit model and the virtual trading hub and the virtual trading hub applying to the DTS are provided in the sections below.

8.4.1 Entry-exit model for DTS capacity

The defining feature of an entry-exit system is that network users can book and use entry and exit capacity independently from each other. A complementary feature is the existence of a virtual point where network users can freely trade gas. Access to the virtual trading point should be available for all network users and from all entry and exit points, in order to enable network users to optimise and balance their portfolios and to facilitate trading in the wholesale market.[106]

A high-level schematic of the interaction between the entry-exit model and the virtual hub applying to the DTS under this package is provided in the figure below.

Figure 8.4 Overview of an entry-exit model for the DTS



Source: AEMC. Note: * denotes multiple exit points across the DTS associated with both connection to the distribution network as well as customers directly connected to the DTS.

Entry capacity gives shippers an entitlement to flow gas onto the DTS, while exit capacity gives shippers an entitlement to take gas off the DTS. A shipper would need to buy 1 unit of entry capacity in order to flow 1 unit of energy onto the system and 1 unit of exit capacity in order to flow 1 unit of energy off the system. Depending on the specific design of the entry-exit system, if a shipper exceeds their exit capacity entitlements for any given gas day, then a shipper may incur overrun charges.

In developed European gas markets, the processes for the sale of entry and exit capacity exhibit a number of similarities. For example, Great Britain, the Netherlands and Germany all have the following features:[107]

- Entry capacity:

106 KEMA, *Study on Entry-Exit Regimes in Gas Part A: Implementation of Entry-Exit Systems*, Corrigendum 11 December 2013, pp. 5-6.

107 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, p. 14.

- utilise auctions for the sale of firm entry capacity – both existing, and incremental new capacity; and
- provide an 'open season' style mechanism to directly contract for new entry capacity where incremental capacity options not applicable.

- Exit capacity:
  - provide a form of application/allocation process for exit capacity associated with retail customers; and
  - utilise auctions for the sale of other exit capacity.

In Great Britain entry and exit capacities are sold principally via auction. Long-term firm exit capacity is however obtained through an application process, with three separate application windows.[108]

In the Netherlands, cross-border capacity sales are conducted via auction. Exit capacity for the distribution systems is allocated automatically to shippers who supply end customers on the distribution network. Capacity for other domestic entry and exit points (for example, transmission connected users) is booked on a first-come-first-served basis. Exit capacity for the distribution systems and capacity for other domestic entry and exit points is priced using a regulated tariff.[109]

In Germany, auctions are only used for firm TSO market area and cross-border capacities. Capacity for internal entry/exit points (that is, points of consumption, storage or production within Germany) and interruptible capacity is sold on a first-come-first-served basis.[110]

The secondary trading of capacity rights is also actively encouraged in these three markets. In Great Britain for example, shippers can trade entry capacity back into the capacity auctions operated by the TSOs. As entry/exit rights these cannot be locationally segmented, though they can seek to 'transfer' their capacity to another location, subject to evaluation by the TSO.[111]

The hoarding of capacity (that is, shippers refusing to on-sell unused capacity to others who might be able to use it) is an intrinsic risk to all transportation regimes involving the long-term reservation of system capacity. This issue appears to have been

108 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, pp. 50-51.

109 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, p. 70.

110 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, p. 30.

111 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, p. 14.

particularly concerning in Europe, where a number of mechanisms have been defined for addressing it, including:[112]

- surrender of capacity - capacity is voluntarily surrendered back to the TSO, with the shipper relieved of its payment obligation if the capacity is re-sold;
- oversubscription and buy back - the TSO auctions any firm capacity that has not been nominated, up to the technical limit of the pipeline;
- firm day-ahead use-it-or-lose-it - capacity that is not nominated the day before the flow is made available to others on an interruptible basis; and
- long-term use-it-or-lose-it - capacity with less than 80 per cent utilisation in a 12-month period may be forced to be surrendered partially or completely.

If an entry-exit model were applied to the DTS, then an assessment of whether hoarding of capacity is likely to be an issue would need to be undertaken and which, if any, of these measures is required to prevent it.

8.4.2 Virtual hub covering the DTS

Package D involves replacing the existing DWGM with a virtual hub that represents a purely wholesale gas commodity market (that is, no implicit allocation of capacity) and complements the entry-exit system. Specifically, the application of a virtual hub across the entire DTS fulfils the requirement of an entry-exit system that gas can be traded independently of its location in the system.

Price discovery at the virtual hub could occur via an exchange-based approach, where buy and sell orders are matched, similar to the Wallumbilla GSH. Consideration would also need to be given as to whether trading and balancing was conducted on the same market platform and the nature of participation (voluntary/mandatory). For example, if it is considered that a voluntary wholesale market is optimal but that trading liquidity is likely to be low for a period following market-start, then some form of mandatory balancing may be required, at least temporarily. Further detail on the price discovery mechanism, and trade-offs between various approaches, has not been considered in this paper.

A virtual hub provides users the possibility to bilaterally transfer the title of gas and/or swap imbalances between network users. The virtual hub is not associated with a physical point within the DTS and parties can trade at it without the need to book entry or exit capacities. Network users have free access from every entry and exit point to trade gas between one-another via the virtual hub; in the above schematic this is indicated by the green and red arrows, which indicate the contractual flow of gas.

Flexible access to and from the entry and exit points provide shippers with options to manage their risk. For example, a shipper could limit their activities to bringing gas

112 Market Reform, *International Gas Markets Study*, Report to the Australian Energy Market Commission, June 2015, pp. 14-15.

into the system and selling at the virtual hub and thus requiring only entry capacity or, alternatively, possessing exit capacity while sourcing all gas from the virtual hub.

In addition, an intermediary trader could be buying and selling gas at the virtual hub without owning any entry or exit capacities at all, assuming that the trading platform (for example, an exchange) is sufficiently developed to offer such products. This encourages liquidity in the wholesale market for gas and the development of a meaningful southern reference price on the east coast.

8.5 Package E: Hub and spoke model

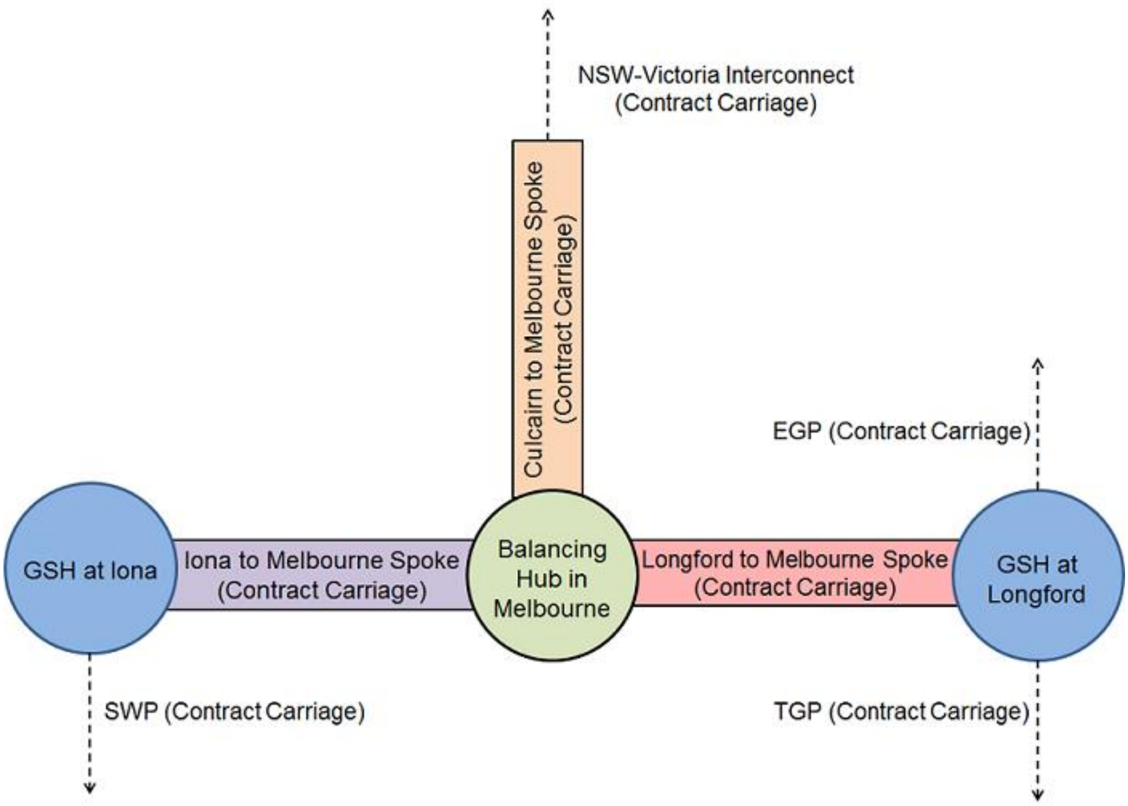
Package E involves the following:

- a balancing hub at Melbourne (the 'hub'); and
- converting all other sections of the DTS to contract carriage (the 'spokes').

Package E also involves establishing GSHs at Longford and Iona where parties can trade wholesale gas.

An overview of Package E is provided in the figure below.

Figure 8.5 The hub and spoke model



Source: AEMC.

This package has been designed primarily to test the concept of converting the transportation arrangements applying to the DTS from market carriage to contract carriage, consistent with the remainder of the east coast. We acknowledge that this package represents a relatively pronounced set of reforms to the current market and so we are interested in stakeholder views on whether the benefits are likely to outweigh the costs in aggregate. In addition, it is our understanding that contract carriage was considered for the DTS at the time of originally designing the DWGM.

This package is consistent with concept 1 established as part of the Wholesale Gas Markets Discussion Paper, that is, multiple physical hub locations on the east coast with balancing arrangements in place at major demand centres.

Each of the specific design features of this package are discussed in the sections below.

8.5.1 Balancing hub at Melbourne

This package involves the establishment of a balancing hub at Melbourne. Specifically, while shippers would be incentivised to balance their injections and withdrawals through imbalance tolerances and penalties contained within transport contracts (as outlined in section 8.5.2 below), the balancing hub in Melbourne would allow for residual balancing when required.

The balancing hub could operate in a similar manner to the Market Operated Service (MOS) in the existing STTM design, which balances the difference between scheduled pipeline flows and what is actually delivered or consumed at the hub. MOS is essentially a pipeline capacity service where shippers, through their contracts with pipeline operators, provide the STTM with a mechanism to store gas if flows to the hub are greater than demand, or supply additional gas if flows to the hub are below demand. MOS is therefore essentially provided through the park and loan pipeline services contained within shippers' contracts with pipeliners.

We note that there is currently daily balancing on the STTM and that balancing may need to be done more frequently for the DTS due to the limited linepack. The concept of MOS would therefore have to encourage balancing over a shorter period than a day (for example, every 4 hours between 6.00am and 10.00pm).

A balancing hub, and the removal of the wider DWGM, would resolve the issues associated with the manner in which the costs of balancing actions taken by AEMO currently (that is, ancillary payments) are recovered from market participants.

We note also that gas may not be able to flow freely between the three spokes of this package due to the physical network characteristics in Melbourne (that is, the inner ringmain). Because of this, hub services are likely to be required at Melbourne to assist this transfer of physical gas.[113]

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

8.5.2 Application of contract carriage to the DTS

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

The conversion of the DTS to a set of contract carriage pipelines is therefore anticipated to resolve both the lack of investment signals currently provided via the DWGM and to encourage timely and efficient investment in pipelines via market-led investment.

However, developing a contract carriage system to apply to the DTS raises a number of complex design issues that would need to be addressed. Each of these design issues is summarised below and, together, imply that the details of a contract carriage model for the DTS may be quite different from the models that apply to other pipelines on the east coast.

Definition of firm and non-firm capacity

In contract carriage regimes the product offered to a market participant under a firm service contract carriage is, in simple terms, the right to convey a maximum amount of gas from one point to another. There are two key aspects to the product being offered:

- the right to convey gas; and
- the maximum amount of gas that can be conveyed over a period of time (for example, an hour).

Defining the product in this way for a simple point-to-point pipeline provides meaningful information to a shipper. Based on this product definition and the cost, the shipper can make commercial decisions as to whether entering a firm contract (or buying secondary market or non-firm capacity) with would be profitable.

While this is simple to do for the relatively point-to-point Longford to Melbourne spoke under this package, it is more difficult for the Culcairn to Melbourne and Iona to Melbourne spokes since they are interconnected (or 'meshed').[114] The definition of firm capacity between any two points on a meshed network is significantly influenced by the expected pattern of injections, withdraws and flows everywhere across the network. If there is to be a single class of firm capacity contracts with equal rights on these two spokes, then firm capacity between any two points would need to be defined conservatively so that the pipeline owner can deliver gas under any plausible pattern of flows across the DTS.

114 Specifically, these two spokes are connected via the Bendigo to Ballarat junction.

To the extent that firm service capacity between any two points needs to be defined conservatively for these reasons, then there would likely be a higher level of non-firm service capacity available than is typically the case in contract carriage pipelines. Resultantly, much of the time the non-firm service would be very close to firm service (that is, low risk of curtailment) and gas fired power stations, interruptible loads and some export loads may be comfortable with non-firm service, which in turn would reduce the demand for firm service.

In addition, firm capacity between any two points could be physically changed, for example when new injection or withdrawal points are added elsewhere in the system.[115] If adding new injection or withdrawal points reduces firm capacity, then changes would likely need to be dealt with contractually.

Further, we note that there would likely be significant issues to be overcome in transitioning the existing rights of market participants provided via AMDQ, although limited, over to a system of contract carriage. Not only would property rights have to be considered but also the allocation methodology itself (for example, auction, first-come-first-served etc).

Imbalance tolerances and penalties

Under contract carriage, shippers must typically match injections and withdraws within tolerance bands ('imbalance tolerances') and penalties apply for non-compliance. These imbalance tolerances would likely need to be narrower than typical contract carriage pipelines under this package because of the limited linepack and the variable demand in the DTS.

Shippers that have a well-diversified portfolio of upstream gas contracts relevant to a contract carriage pipeline can reduce their risk of exceeding pipeline tolerances and paying any associated penalties. On the other hand, shippers that do not have a well-diversified portfolio (for example, small, new-entrant retailers) may face a greater risk of exceeding pipeline tolerances, particularly on the DTS where linepack is low and demand is highly variable.

In order to manage exposure to imbalance penalties shippers would need sophisticated metering and information systems to support forecasting of imbalances. While we do not have any evidence as to the extent of these costs, if they are material, small new entrant shippers may face a competitive disadvantage relative to larger more established shippers.

Under the DWGM current rules, the market operator is responsible for physically managing the system. There may therefore be an efficiency loss associated with shifting the responsibility for short term forecasting and control of flows back to

115 While we note that the Longford to Melbourne spoke under this package represents a relatively point-to-point pipeline system, it may not always be the case going forward. Specifically, new sources of convention and unconventional gas may emerge in the future and seek to connect to this spoke.

shippers under this package when they have less knowledge of the dynamics of the DTS pipeline system than the pipeline operator.

Some contract carriage arrangements include the use of operational flow orders, which require shippers to take action to balance their withdrawals and injections to protect the operational integrity of the pipeline. We understand that these orders are rarely issued but note that the limited linepack in the DTS and need for tight control of gas scheduling may increase the risk of operation flow orders being issued.

Backhaul services

Contract carriage arrangements often provide backhaul services to shippers, which are typically a limited firm service applying to withdrawals at the defined withdrawal off-take, providing backhaul capacity rights for notional flows against the predominant flow and contingent upon forward haul flows occurring. The backhaul capacity right is limited to the reserved forward haul capacity of the relevant pipeline and transportation charges are usually rebated to holders of firm capacity rights.

Should contract carriage be applied to the DTS, these backhaul services would need to be highly developed given the importance of bi-directional flows. For example, both Iona and Culcairn are currently injection and withdrawal points and so the contracts applying to these two spokes would likely require the provision of backhaul services.

Secondary trading of capacity

In order to trade gas at Longford and Iona, sellers must have capacity rights to transport gas to the point of sale, and buyers must have capacity rights to transport gas away from the point of sale. The ability to ship gas into and out of a hub area is particularly important for liquidity to emerge at physical hubs, or narrowly defined virtual hubs, where gas is traded at specific physical locations on the pipeline system.[116]

The ability of pipeline capacity to be freely traded on a secondary market is therefore a key requirement of this package's success. The appropriateness of the capacity trading arrangements operating on the current contract carriage pipelines on the east coast, and the possibility of any changes to these arrangements, are being considered through the broader East Coast Review as part of the pipeline capacity trading workstream, as illustrated earlier in Figure 1.1.

Investment coordination

The Commission considers that a benefit of the current market carriage arrangements are that they allow for the explicit consideration of investments that may be beneficial from a system-wide perspective but not necessarily from the perspective of individual users (that is, where coordination issues exist). While we are unaware of any such investment not occurring on existing contract carriage pipelines on the east coast to-

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

date, we would be interested to hear from stakeholders on whether this is likely to be an issue if contract carriage were to be applied to the three spokes developed under this package given the physical characteristics of the DTS (that is, the relatively large degree of pipeline interconnectedness).

8.5.3 Longford and Iona GSHs

Under Package E, parties would be able to trade physical gas on the GSHs at Longford and Iona. These represent locations that connect sources of production with demand, that is:

- Longford, marks the intersection between the Longford to Melbourne Pipeline, the Eastern Gas Pipeline and the Tasmanian Gas Pipeline and can receive gas from the Gippsland Basin; and
- Iona, represents a location that is close to both storage and production in the Otway Basin, as well as gas-fired power stations in Victoria and South Australia.

As noted above, this package is consistent with concept 1 presented as part of the Wholesale Gas Markets Discussion Paper. This concept envisages that parties would have the ability to trade standardised products at GSHs, such as currently occurs at the Wallumbilla GSH exchange. This concept is similar to the US, which has more than 30 physical hubs ('market centres') that are typically located at the intersection of major pipelines that operate on the contract carriage model. While there are numerous hubs where trading can occur in the US, the Henry Hub has emerged as the principal reference price, and movements in price at this hub provide a good indicator of how prices are generally changing at other hubs across the country.

A key question therefore exists as to whether there are likely to be sufficient potential market participants and volumes of gas to generate deep and liquid trading at Longford and/or Iona (as well as multiple other different locations on the east coast envisaged as part the wider east coast - for example, Wallumbilla, Moomba and Gladstone), and for a meaningful reference price to emerge at one of the hubs.

Assuming trading can become sufficiently deep and liquid at Longford and/or Iona, this package envisages that financial derivative products are likely to emerge to assist participants in managing price risk. This will be encouraged by that fact that the underlying physical market design produces a reference price that encompasses all of the price risk faced by traders (including any uplift or other charges) and market liquidity has reached a point where counterparties are confident that the hub price represents the underlying value of gas and cannot be easily moved by the actions of a small number of players.

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

A Glossary

AMDQ: A collective term for the transportation rights on the DTS, which includes authorised MDQ and AMDQ credits.

AMDQ credit: Transportation rights that were allocated on additions to the original DTS pipeline system—above the initial 990 TJ of authorised MDQ on the Melbourne–Longford pipeline system.

Authorised Maximum Interval Quantity (AMIQ): Current market participants who intend to use their AMDQ to hedge against congestion uplift assign a percentage of their AMDQ as AMIQ for each scheduling interval.

Authorised MDQ: Transportation rights that were allocated for the original 990 TJ capacity on the Melbourne–Longford pipeline system when the DTS was first set up.

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

Bid: A quantity of gas at a specified price that a market participant offers to inject into or withdraw from the transmission system during a gas day.

Constraint: Any limitation causing a defined gas property (such as minimum pressure) to fall outside its acceptable range.

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

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

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

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

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

Maximum Daily Quantity (MDQ): Maximum daily quantity of gas supply or demand.

Maximum hourly quantity (MHQ): Maximum hourly quantity of gas supply or demand.

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

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

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

Tariff D: The transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or MHQ greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique meter ID number.

Tariff V: The transportation tariff applying to non-tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users.

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

VicHub: The interconnection between the Eastern Gas Pipeline and the DTS at Longford, which facilitates gas trading at the Longford hub.

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

B Arrangements to facilitate exports from Victoria

There are a number of options open to market participants seeking to flow gas from Victoria to interconnected markets, some of which require participation in the DWGM and others which do not. Each option requires market participants to have in place certain arrangements, and to take certain actions, to ensure (as much as possible) that the quantity of gas it wishes to flow is able to flow. A summary of the various options available to export gas from Victoria to other jurisdictions is set out below.

B.1 Exports from Victoria to NSW via Culcairn

There are a number of actions a market participant would need to take to export gas from the DWGM to NSW, via the Interconnect. First, it would need to obtain a transport contract with APA GasNet for access to, and capacity on, the Moomba to Sydney Pipeline to be able to receive the gas in that pipeline from the DWGM. It would also need to register with AEMO as a participant in the DWGM.

To have its export quantity was scheduled in the DWGM for withdrawal at Culcairn, the market participant would need to take a number of actions on the DWGM. It would also need to follow its contractual obligations with APA GasNet to nominate the flow of the exported gas on the Moomba to Sydney Pipeline. In relation to the former, there are a number of options available in terms of the arrangements that a market participant can put in place, and actions it can take, to ensure its required export quantity is scheduled for export.

The simplest approach would be for the market participant to submit a withdrawal bid at Culcairn for the desired export quantity, at a price it was willing to pay for that quantity. In so far as other controllable bids for withdrawals at Culcairn did not exceed the Interconnects capacity, and as long as the market clearing price was less than the participant's bid price, the withdrawal at Culcairn would be scheduled in the DWGM.

This alone, however, will not provide certainty for the exporting participant in terms of either a firm cost for the export quantity, nor firm rights to export capacity. In relation to the former, the cost would be dependent upon DWGM market price outcomes (up to the participant's bid price). In relation to the latter, its access to export capacity could be dependent on other participants' controllable withdrawal bids at Culcairn (price and quantity) and whether other participants hold AMDQ or AMDQ cc at Culcairn.

There are options available to a market participant to mitigate these particular risks. For example, matching injections of export quantities could manage imbalance and market price risk, while holding AMDQ or AMDQ cc at Culcairn would mitigate the risk of curtailment.

The other options available to market participants to arrange for exports to be scheduled from the DWGM to NSW via Culcairn are summarised in the Figure B.1. The risks associated with each option and the steps available to manage those risks are also included.

Figure B.1 Arrangements to Facilitate DWGM Exports at Culcairn

Minimum Requirements

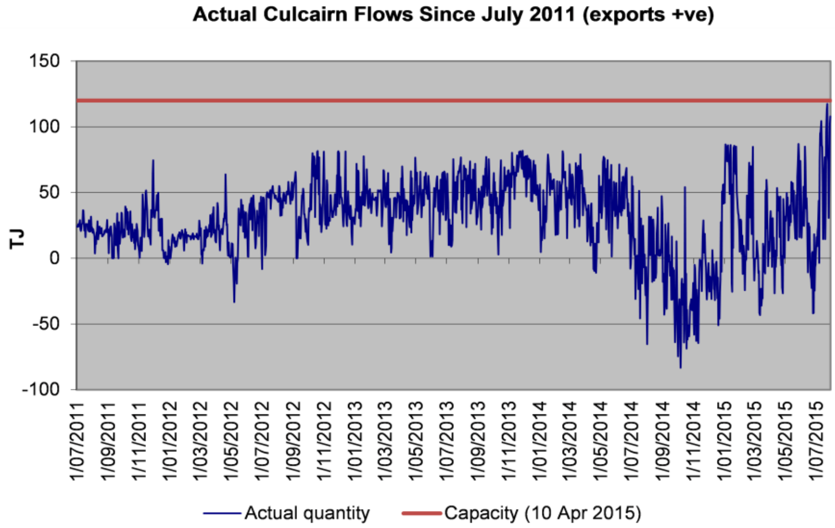
- Contractual arrangement with APA for capacity on the Moomba-Sydney pipeline
- Register with AEMO as market participant in DWGM
- Nominate required gas receipt into Moomba-Sydney pipeline at Culcairn under contract with APA (day ahead)
- Submit controllable withdrawal bid at Culcairn in the DWGM, for desired quantity and price

Option	Risks	Management of Risks
1. Minimum requirements above – No associated injections in DWGM – No AMDQ assigned at Culcairn	Without any injections into the DWGM, the full export quantity will be subject to the Victorian market price up to the participant's withdrawal bid price.	Risk capped by choosing appropriate bid price, but the market price paid could be set at any level between zero and the participant's bid price.
	Participants' withdrawal may not be scheduled if: • the market price is set higher than the participants' bid price; or • there are other higher-priced withdrawal bids at Culcairn that cumulatively exceed the interconnect export capacity.	Set withdrawal price bid at the highest price that remains commercially viable. The cost of the export quantity can be capped but will remain variable dependent on market price outcomes. Scheduling of the export withdrawal quantity cannot be guaranteed when interconnect is scheduled to its capacity.
2. Negotiate an acceptable contractual price with a supplier for gas to be injected into the DWGM to match the required export quantity. Submit injection offers that match desired export quantity at a low price (zero) in the DWGM to ensure that injections are scheduled. Bid controllable withdrawal at Culcairn at a price up to VoLL to ensure the withdrawal is scheduled, subject to other VoLL priced withdrawal bids at Culcairn not exceeding the capacity of the interconnect.	To the extent that scheduled injections match the scheduled export quantity, there will be no exposure to imbalance payments or the DWGM market price.	
	If withdrawals scheduled and delivered but injections not scheduled – exposure to imbalance payments up to market price (potentially up to VoLL) for full daily export quantity.	Could rebid to mitigate this in subsequent schedules by either reducing the scheduled export withdrawals or seeking to have injections scheduled.
	If withdrawals scheduled and delivered, injections scheduled but not delivered (e.g. unexpected plant failure after 6.00am schedule) – exposure to deviation payments for under-delivery of injections.	Could rebid to mitigate this in subsequent schedules by either reducing the scheduled export withdrawals or seeking to have other injections scheduled. May require back up contracts or swaps to be in place to provide insurance against failure of a single source of gas. Could also seek to negotiate contractual remedy for failure of supplier to deliver gas injections (but likely to be difficult, probably covered by suppliers' standard Force Majeure provisions)
	Despite bidding for withdrawals at up to VoLL, other participants do the same, with cumulative VoLL-priced withdrawal bids at Culcairn exceeding the capacity of the interconnect – If Culcairn export capacity is exceeded, withdrawal bids will be scheduled in descending price order up to the export capacity – If there are equally priced bids then those bids that are associated with AMDQ assigned at Culcairn for tie-breaking purposes will be given priority – If there are equally priced bids for which none (or all) have associated AMDQ assigned at Culcairn, the scheduled quantities	Obtain AMDQ and assign it at Culcairn to cover required export quantity.

	will be proportionally scaled down so that the total scheduled withdrawal quantity is at the interconnection capacity	
3. Obtain and assign AMDQ at Culcairn	Assigned AMDQ only provides scheduling priority where bids are otherwise equal. Therefore, unless the withdrawal bid is priced at VoLL, then even with associated AMDQ assigned at Culcairn there remains a risk that higher priced bids could be scheduled first up to the interconnection capacity.	If bids are priced at VoLL, with associated AMDQ assigned at Culcairn then, unless there are abnormal system operating conditions that physically limit the amount of gas that can be delivered at Culcairn from the DTS, scheduling of desired export quantity is assured.

Figure B.1 illustrates that the Culcairn Interconnect has been well utilised for exports from Victoria over the past five years.

Figure B.2 Actual Culcairn flows since July 2011



Source: National Gas Market Bulletin Board (www.gasbb.com.au)

B.2 Exports from Victoria to NSW via the Eastern Gas Pipeline

A market participant wishing to export gas from Victoria to NSW could also do so via the Eastern Gas Pipeline. Given that the Eastern Gas Pipeline is directly connected to the Esso Longford gas processing facility, exports via the Eastern Gas Pipeline do not necessarily need to flow through the DTS and, hence, do not require a market participant to participate in the DWGM.

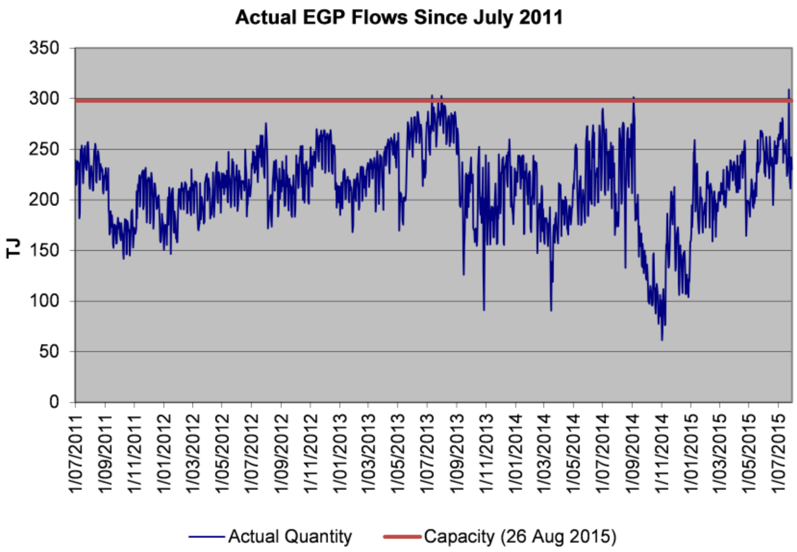
Bypassing the DWGM to export gas to NSW via the Eastern Gas Pipeline would require a market participant to have negotiated with Esso/BHPP for contractual gas supplies from Longford. It would also need to have negotiated a gas transportation agreement (GTA) with Jemena for pipeline capacity on the Eastern Gas Pipeline.

Alternatively, a market participant wishing to export gas from the DTS to NSW via the Eastern Gas Pipeline could do so provided it had registered with AEMO as a participant in the DWGM, and held a GTA for the Eastern Gas Pipeline. There have been no physical exports from the DTS via VicHub to the Eastern Gas Pipeline since 2010.

There appear to be no barriers preventing exports from the DTS via VicHub in terms of market arrangements. That such exports have not taken place since 2010 is more likely because the Longford plant is connected directly to the Eastern Gas Pipeline meaning movement of gas through the DTS, and hence participation in the DWGM, is unnecessary.

Figure B.2 illustrates that the Eastern Gas Pipeline has been well utilised for exports from Victoria over the past five years.

Figure B.3 Actual EGP flows since July 2011



Source: National Gas Market Bulletin Board (www.gasbb.com.au)

B.3 Exports from Victoria to South Australia via the SEA Gas Pipeline

A market participant wishing to export gas from Victoria to South Australia could do so via the SEA Gas Pipeline. In addition to being directly connected to the DTS, the SEA Gas Pipeline is also connected to (or adjacent to) a number of gas production facilities near Port Campbell. These facilities include the Minerva and Otway gas plants and the Iona Underground Storage facility.

Similar to the Eastern Gas Pipeline, the connection of the SEA Gas Pipeline to multiple production facilities means that a market participant wishing to export gas from Victoria to South Australia could do so without having to participate in the DWGM. In order to bypass the DWGM, it would need to have a contract(s) for the supply of gas from a production facility at Port Campbell or Iona. It would also need to have negotiated with South East Australia Gas P/L for a GTA on the SEA Gas Pipeline.

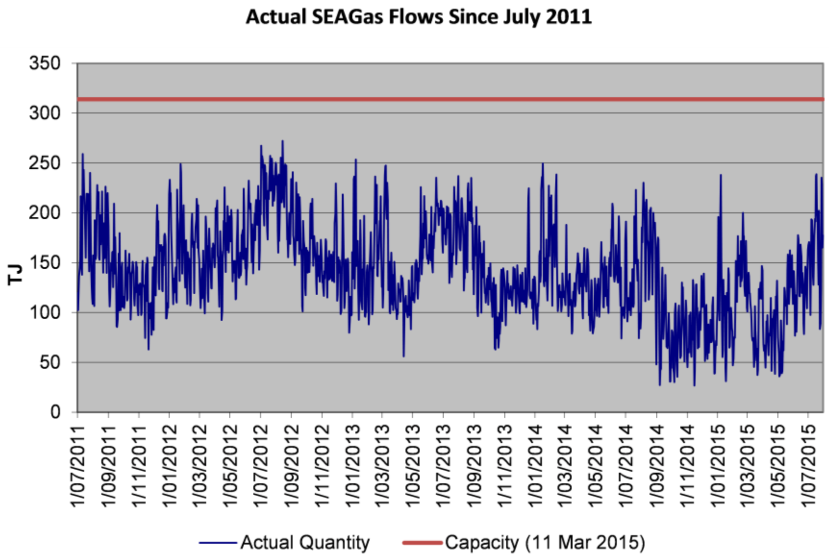
Alternatively, a market participant could export gas from the DTS to South Australia. The market participant would need to register as a participant of the DWGM with AEMO, and would also need access to pipeline capacity on the SEA Gas Pipeline.

While market participants do move gas from the DTS to store in the Iona Underground Storage facility, gas has not been physically withdrawn from the DWGM to flow on the SEA Gas Pipeline since it was commissioned in 2003.

Similar to exports from the DTS via VicHub, there appear to be no barriers to market participants withdrawing from the DWGM for export to South Australia via the SEA Gas Pipeline. Access to pipeline capacity on the DTS for this purpose would unlikely be problematic due to the flow on the South West Pipeline predominantly being in the opposite direction.

Figure B.3 illustrates that the SEA Gas Pipeline has been well utilised for exports from Victoria over the past five years.

Figure B.4 Actual SEAGas flows since July 2011



Source: National Gas Market Bulletin Board (www.gasbb.com.au)

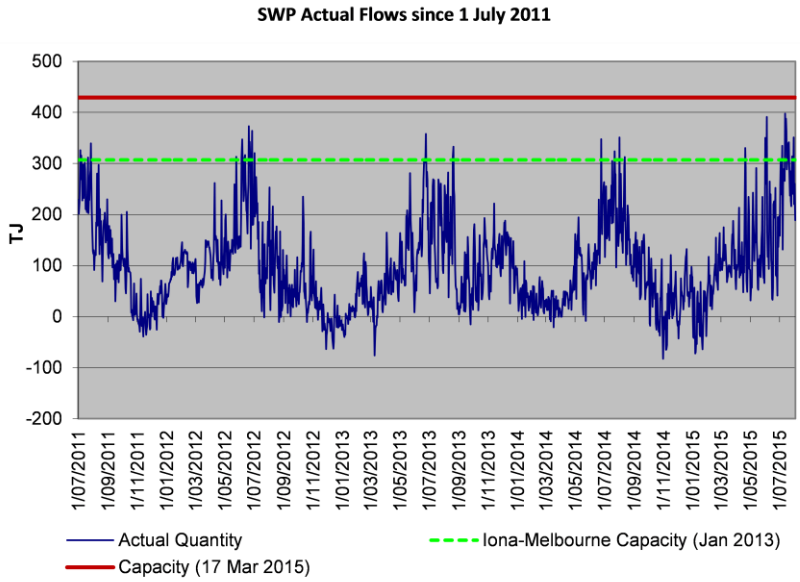
B.4 Exports from Victoria to NSW via South West Pipeline

In the past, concerns have been raised that the capacity of the South West Pipeline from Iona to Melbourne was not adequate to transport the full available capacity of Iona Underground Storage and gas production facilities at Port Campbell and Iona to Melbourne.

Figure B.4 illustrates that, to date, flows on the SWP have not reached current capacity. However, for a number of reasons it is conceivable that increased flows on SWP may be required in future to support Victorian exports via Culcairn.

In light of the revised projections of northern exports (and APA GasNet targeting further expansion of the northern export capacity), it is understood that APA GasNet and AEMO are reviewing the case for an upgrade of the DTS which would, among other things, increase SWP capacity ahead of broader consultation for APA GasNet's next access arrangement.

Figure B.5 Actual SWP flows since 1 July 2011



Source: National Gas Market Bulletin Board (www.gasbb.com.au)

C Authorised Maximum Daily Quantity

Shippers utilising the DTS cannot reserve firm capacity (unlike contract carriage pipelines). They may, however, have an Authorised Maximum Daily Quantity (AMDQ) allocation or an AMDQ credit certificate (AMDQ cc).[117] This appendix presents the history of AMDQ and AMDQ cc.

AMDQ was first allocated at market start and was (and has remained) commensurate with the capacity of the Longford-Melbourne pipeline at that time when it was the primary sole source of gas supply for the DWGM. The rights to the existing 990TJ of capacity were allocated to customers in two tranches (recognising that the DTS was comprised of pre-existing assets that had at least partially been paid for by existing customers of the Victorian Gas and Fuel Corporation):

- large industrial and commercial (Tariff D) sites were allocated AMDQ to match their maximum daily quantity under contracts with the Victorian Gas and Fuel Corporation at the time; and
- the balance of 990 TJ, after Tariff D allocations, was allocated as Tariff V block AMDQ to all small commercial and residential customers.[118]

The rationale for allocating the original AMDQ to customers rather than market participants, retailers or shippers was to not create a barrier to retail competition.[119]

The DTS has expanded and extended since 2008 and the new pipeline capacity has been allocated as AMDQ credit certificates (AMDQ cc).[120]

As new pipeline capacity has become available, AMDQ cc have been created to provide similar benefits to those arising from AMDQ on the Longford pipeline.[121] The increase in pipeline capacity resulting from an extension or expansion project is agreed between APA GasNet (as the DTS owner) and AEMO (the operator of the DTS and the DWGM). Once agreement is reached and the new capacity becomes operational, new certificates are created.

AEMO allocates the AMDQ cc to market participants for quantities and periods as directed by APA GasNet (which reflect the outcome of a competitive tender process

---

117 Unless otherwise stated, the information in this sub-section references: AEMC, *National Gas Amendment (Portfolio Rights Trading) Rule 2014*, Final Rule Determination, 27 November 2014.

118 Market participants supplying Tariff V customers were allocated a share of the Tariff V block AMDQ proportionately to their portfolio Tariff V demand on system peak demand days.

119 For example, if AMDQ were held by retailers, there was a concern that those retailers who won customers from rival retail businesses would then be forced into a position of either trying to negotiate with that rival retailer to sell them AMDQ, or take on additional risk.

120 Maximum system capacity of the DTS is currently approximately 1,350 TJ per day. See: AEMO website, available at: http://www.aemo.com.au/Gas/Planning/Victorian-Gas-DTS-Capacity

121 Since the commencement of the DWGM, the capacity of the DTS has increased as a result of numerous augmentations, including the Interconnect, the South West Pipeline, the connection of the former Western Transmission System, the Brooklyn Lara Loop and the BassGas project.

APA GasNet manages). In this process, interested market participants are able to tender for an amount of AMDQ cc for a specified period.[122]

The figure below illustrates the expansion of the DTS since 1998, which has resulted in a total of 508 TJ of AMDQ cc made available for injections into the DWGM.

Figure C.1 Allocation of AMDQ and AMDQ cc as at 2014

AMDQ cc is not differentiated by final customer (Tariff V or D) and is not allocated directly to customers. Rather, market participants with AMDQ cc must advise AEMO whether the allocated AMDQ cc are to be nominated to either:

- specific customer sites; or
- the nominal reference hub.

122 However, the AEMC notes that there are no requirements for this process to occur.

D Overview of relevant gas rule change requests

This section provides a summary of AEMC rule changes which are complete, underway or pending and which impact:

- the Victorian DWGM;
- AEMO's role in the DWGM; or
- APA GasNet's business of owning the Victorian DTS.

A full list is available on the AEMC website: www.aemc.gov.au

Prioritisation of Tied Controlled Withdrawal Bids Rule proposal	
Reference: GRC0001 Stage: Rule made Proponents: AEMO Commenced: 07-Jun-2010	On 16 November 2010, the Australian Energy Market Operator (AEMO) submitted a rule change request seeking to change the tie-breaking rules AEMO used to schedule gas withdrawals in the Victorian declared wholesale gas market (DWGM) under the National Gas Rules (NGR). Previously, multiple controllable withdrawal bids considered to be "equally beneficial" to the market were scheduled on a pro-rated basis. The proposal was to change that situation so that, where multiple controllable withdrawal bids were considered to be "equally beneficial" to the market, controllable withdrawal bids would be prioritised over other bids if the bidder held Authorised Maximum Daily Quantity (AMDQ) units or Authorised Maximum Daily Quantity credit certificates (AMDQ cc's). On 25 February 2010, the Commission decided not to make a draft rule in relation to the Rule change request. Following the Commission's consideration of submissions and further analysis, on 20 May 2010 the Commission decided to proceed with the rule. The rule commenced on 7 June 2010.

Calculation of Interest for Gas Markets	
Reference: GRC0002 Stage: Rule made Proponents: AEMO Commenced: 4-Nov-2010	On 16 November 2010, AEMO submitted a rule change request seeking to allow AEMO to use a simple interest methodology to calculate under the DWGM rules, the Short Term Trading Market (STTM) rules, and the Natural Gas Services Bulletin Board rules. It also sought to apply one definition of 'interest rate' and 'default interest rate' to all these rules, to be centrally located in the NGR. On 4 November 2010, the made a rule consistent with AEMO's description of its proposed rule. The rule commenced immediately.

Dandenong Liquefied Natural Gas Storage Facility	
Reference: GRC0003 Stage: Rule	On 8 June 2010, AEMO submitted a rule change request seeking to change the NGR to partially liberalise the operation of the Dandenong LNG storage facility due to decreased reliance on LNG for system security. The 12,000 tonnes Dandenong LNG storage facility provides LNG storage services to participants in the DWGM and to others. The proposed rule change sought the removal of

Dandenong Liquefied Natural Gas Storage Facility	
made Proponents: AEMO Commenced: 16-Dec-2010	AEMO's right to 3000 tonnes of storage capacity in the Dandenong LNG storage facility for an LNG reserve. On 16 December 2010, the Commission made its final rule determination, and on 23 December 2010 this was updated to account for a minor amendment. In the final rule determination, the Commission decided to make a rule incorporating the key elements of AEMO's Rule change request, but modified it to include only declared LNG storage providers (instead of all LNG storage providers). The rule commenced immediately.

Various Hedging Instruments in the Declared Wholesale Gas Market	
Reference: GRC0004 Stage: Rule made Proponents: AEMO Commenced: 17-Apr-2012	On 17 November 2010, AEMO submitted a rule change request seeking to enable DWGM participants to use market hedging instruments more effectively and therefore more efficiently manage their trading risks. More specifically, it sought to increase the flexibility with which participants in the DWGM can use AMDQ and Authorised Maximum Interval Quantity (AMIQ) profiles to manage financial risk. On 25 August 2011, the Commission made a rule to enable participants in DWGM to better manage their financial risks. The rule reflected AEMO's proposed policy. The rule commenced on 17 April 2012.

Reference Service and Rebateable Service Definitions	
Reference: GRC0012 Stage: Rule made Proponents: AEMO Commenced: 02-May-2013	On 5 August 2011, the Australian Energy Regulator (AER) submitted a rule change request seeking to amend the definitions of ‘reference service’ and ‘rebateable service’ in the NGR. The AER considered that the application of the existing definitions would result in access arrangement decisions which, in some circumstances, would not satisfy the most efficient investment in and use of pipeline services, and would be contrary to the long term interests of consumers with respect to price. On 6 October 2011, the Commission commenced consultation on the rule change request with a consultation paper. On 13 September 2012, the Commission published a further consultation paper which sought stakeholder comment on a variation of the draft rule that only would apply to pipeline services provided by the Victorian declared transmission system. On 1 November 2012, the Commission published a final rule for the reference service and rebateable service definitions rule change request. The final rule differs from the rule proposed by the AER in that it makes changes only to the reference service definition. The final rule does not amend the current rebateable service definition. The final rule commenced on 2 May 2013.

Economic Regulation of Network Service Providers	
Reference: GRC0011 Stage: Rule	On 5 August 2011, the AER and Energy Users' Rule Change Committee (EURCC) submitted a rule change request seeking to alter the ways that ‘rates of return’ and asset base sixe are calculated in both the National Electricity Rules (NER) and the NGR. The request identified that the most significant factors that determine the revenues of network service providers are their rates

Economic Regulation of Network Service Providers	
made Proponents: AER and EURCC Commenced: 29-Nov-2012	of return on capital, and the size of their regulated asset bases. On 29 November 2012, the Commission published a final rule which included significant changes to the rate of return provisions of the NGR. These amendments were applicable to the AER in the eastern states and the Economic Regulation Authority in Western Australia. The rule commenced immediately.

Economic Regulation of Network Service Providers	
Reference: GRC0011 Stage: Rule made Proponents: AER and EURCC Commenced: 29-Nov-2012	On 5 August 2011, the AER and Energy Users' Rule Change Committee (EURCC) submitted a rule change request seeking to alter the ways that 'rates of return' and asset base sixe are calculated in both the National Electricity Rules (NER) and the NGR. The request identified that the most significant factors that determine the revenues of network service providers are their rates of return on capital, and the size of their regulated asset bases. On 29 November 2012, the Commission published a final rule which included significant changes to the rate of return provisions of the NGR. These amendments were applicable to the AER in the eastern states and the Economic Regulation Authority in Western Australia. The rule commenced immediately.

Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets	
Reference: GRC0013 Stage: Rule not made Proponents: Major Energy Users Inc. Commenced: N/A	In October 2011, Major Energy Users Inc. submitted a rule change request seeking to introduce optimisation of the Regulatory Asset Base (capital base), and remove incentives for the replacement of fully or partially depreciated assets still in operation, with respect to electricity and gas networks. The proponent was concerned that existing arrangements allowed network service providers to over-invest in network capital assets, with consumers being required to pay for this over-investment. The proposed rule sought to address this by introducing optimisation for these assets. On 13 September 2012, the Commission published a final rule determination that did not support the proposal, noting that the potential benefits were outweighed by increased complexity, costs and risks.

Pipeline operator cost recovery processes	
Reference: GRC0017 Stage: Rule made Proponents: AER Commenced: 27-June-2013	On 1 June 2012, the AER submitted a rule change request seeking to allow pipeline operators to recover costs incurred when providing allocation services to the market operator service in the short term trading market (STTM), and aggregation and information services in the National Gas Market Bulletin Board. On 27 June 2013, the Commission published a final rule that ensures that gas market participants will not pay the costs incurred by pipeline operators in providing information services without AER review. The final rule is largely reflective of, and consistent with, the draft rule. The rule commenced immediately.

Portfolio Rights Trading	
Reference: GRC0021 Stage: Rule not made Proponents: AEMO Commenced: N/A	AEMO identified a number of barriers which it considered limited the ability of market participants to acquire authorised MDQ (AMDQ) and AMDQ credit certificates (AMDQ cc) to meet their injection tie-breaking and uplift hedge needs. To address this problem, AEMO proposed a number of amendments to the NGR to introduce Portfolio Rights Trading in the DWGM. The proposed mechanism was intended to enable market participants to more readily carry out short term trades of the market benefits attached to AMDQ and AMDQ cc. In its draft rule determination, the Commission determined to make a draft rule in line with the rule proposed by AEMO. The Commission was satisfied that the draft rule, if implemented, would promote competition (by facilitating access to unused pipeline capacity), promote flexibility (by introducing well-functioning and flexible pipeline trading arrangements) and encourage efficient use of, and investment in, gas transmission capacity (by encouraging the reallocation of unused pipeline capacity between market participants). However, in its final rule determination, the Commission determined not to make a rule. Following its draft rule determination, a number of matters arose which meant that the Commission was unable to conclude with certainty that the potential benefits of making AEMO's proposed rule would outweigh the potential costs of doing so. These matters included the announcement by AEMO of revised costs, and a new timeframe for the proposed implementation of the PRT mechanism. In light of a number of matters, the Commission was no longer satisfied that the proposed rule would promote the national gas objective.

Publication of the Gas Statement of Opportunities (GSOO) and gas Victorian Annual Planning Report (VAPR)	
Reference: GRC0022 Stage: Rule made Proponents: AEMO Commenced: 1-Apr-2014	On 26 September 2013, AEMO submitted a rule change request seeking to change the publication dates of the GSOO and gas VAPR. AEMO considered that this would allow for more time to include updated winter data and for stakeholder comments. The request also sought to decrease the publication frequency of the gas VAPR from annually to biennially. On 13 March 2014, the Commission published a final rule supporting these measures. This rule change request was assessed under an expedited rule making process as a non-controversial rule. The rule commenced on 1 April 2014.

National Gas Bulletin Board Capacity Outlooks	
Reference: GRC0024 Stage: Rule made Proponents: AEMO Commenced: 8-Jan-2015	On 18 November 2013, AEMO submitted a rule change request seeking to change the level of short- and medium-term capacity outlook information that is required to be published on the Bulletin Board by gas pipeline, production and storage facility operators. AEMO considered that this would reduce information asymmetries between market participants, and improve the adequacy of the information. On 1 May 2014, the Commission published a final rule supporting these measures, and extended them to include confidentiality provisions relating to the information provided by facility operators to the Bulletin Board. The rule commenced on 8 January 2015.

Setting the Opening Capital Base	
Reference: GRC0025 Stage: Rule made Proponents: AEMO Commenced: 2-Oct 2014	On 11 November 2013, the AER submitted a rule change request seeking to require the AER (and the Economic Regulation Authority in Western Australia) to remove any benefits or penalties that would occur for network service providers due to a difference between the estimated and actual final year capital expenditure used to set the opening capital base. Gains or losses unrelated to the efficiency of service providers, the AER submitted, conflict with the national gas objective because they can adversely affect pipeline investment and usage incentives, and lead to price distortions. On 2 October 2014, the Commission made a final rule which amends how economic regulators calculate the value of a regulated gas pipeline for each access arrangement period. The calculation must now include the removal of any benefit or penalty arising from the difference between estimated and actual capital expenditure in the final year of a prior access arrangement period. The rule commenced immediately.

Removal of Force Majeure Provisions in the DWGM	
Reference: GRC0027 Stage: Rule made Proponents: AEMO Commenced: 04-May-2015	On 6 February 2014, AEMO submitted a rule change request to the Commission seeking to change the NGR to remove force majeure provisions, and clarify the rules relating to the administered pricing procedures, as they apply to the Victorian DWGM. The force majeure provisions are designed to protect market participants from the financial impacts of events beyond their reasonable control. AEMO sought to remove the provisions as it considered them to be redundant and ineffective. On 11 December 2014, the Commission published its final rule determination and final rule on the removal of force majeure provisions in the Victorian DWGM. It considered that the final rule is likely to contribute to the achievement of the NGO by clarifying the rules for the Victorian DWGM and aligning them with the current market design. The final rule clarifies how the market is to operate in times of market stress, facilitating more accurate decisions and appropriate risk management practices. The rule commenced on 4 May 2015.

DWGM - AMDQ allocation	
Reference: GRC0029 Stage: Pending Proponents: AEMO Commenced: N/A	On 13 November 2013, AEMO submitted a rule change request seeking to amend the NGR to address gaps and inconsistencies in the allocation of AMDQ and AMDQ cc's. The proposed rule change seeks to simplify the rule structure, ensure that expansions to the declared transmission system will only result in the allocation of additional AMDQ cc's, and ensure that AEMO will only allocate any relinquished AMDQ. The Commission has not yet initiated the rule change process for the request.

Removal of Gas Bulletin Board emergency information page	
Reference: GRC0031	On 14 November 2014, AEMO submitted a rule change request seeking to remove the requirement in the National Gas Rules for an emergency

Removal of Gas Bulletin Board emergency information page	
Stage: Rule Made Proponents: AEMO Commenced: 7-May-2015	information page on the Natural Gas Services Bulletin Board. The emergency information page was a place for gas market participants to exchange information during multi-jurisdiction emergency incidents, however, it has never been used and was not relied on by more recent multi-jurisdiction emergency management processes. AEMO sought to remove the information requirement as it considered it was redundant, introduced undue complexity, and resulted in conflicting messages, confusion and sub-optimal decision making. On 23 April 2015, the Commission published its final rule determination supporting AEMOs proposal with minor amendments. The rule commenced on 7 May 2015.

Enhanced Information for Gas Transmission Pipeline Capacity Trading	
Reference: GRC0033 Stage: Consultation Proponents: COAG Energy Council Commenced: 16-Jul-2015	On 30 March 2015, the COAG Energy Council submitted a rule change request seeking to increase the amount of information that gas market participants are required to provide to AEMO for publication on the National Gas Services Bulletin Board. The request follows a Regulation Impact Statement process that considered policy options to increase trade in gas transmission pipeline capacity. The rule change request identifies a need for additional information to lower transaction costs associated with pipeline capacity trading, provide stakeholders with a better understanding of gas flows, and enhance AEMO's monitoring and operational functions. Submissions on the consultation paper closed 13 August 2015.

DWGM operating schedules	
Reference: GRC0034 Stage: Pending Proponents: AEMO Commenced: N/A	On 27 March 2015, AEMO submitted a rule change request to amend DWGM operating schedules. The proposed rule change seeks to enable AEMO to produce operationally feasible schedules and instructions, and reduce trading risk for market participants. The Commission has not yet initiated the rule change process for the request.

E Assessment framework

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

The terms of reference for each review set out the factors that the AEMC must have regard to when undertaking the two reviews.[123] The assessment framework integrates the factors and articulates the relationship between them. High level principles that guide our market development and rule making work are also outlined, along with attributes that we consider are associated with a well-functioning, workably competitive gas market.

E.1 Assessment framework structure

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

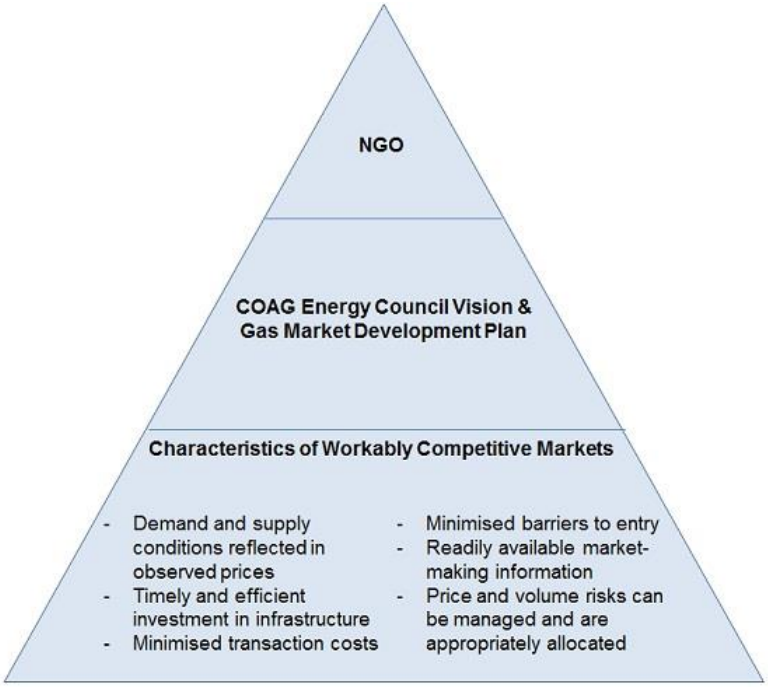
In applying the NGO, the AEMC will have regard to the Energy Council's Vision and Gas Market Development Plan.[124] The Vision is a statement agreed by the Commonwealth, state and territory energy ministers setting out the high level direction that gas market development should take in Australia for the NGO to be achieved. The Gas Market Development Plan is a program of work currently underway that supports the Vision.

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

123 The terms of reference for the two reviews are available on the AEMC's website: www.aemc.gov.au

124 See: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

Figure E.1 Assessment framework



E.2 National gas objective

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

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

The NGO is structured to encourage energy market development in a way that supports the following:[125]

1. efficient allocation of natural gas and transportation services to market participants who value them most, typically through price signals that reflect underlying costs;

2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs; and

3. ability of the market to readily adapt to changing supply and demand conditions over the long-term by achieving outcomes 1 and 2 overtime.

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

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

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

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

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently;
- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to imitate the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;
- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them; and
- market and regulatory frameworks should be flexible and provide firms with a clear and consistent set of rules that allow them to independently develop business strategies and adjust to changes in the market. Frameworks should be resilient to changing supply and demand conditions, and patterns of flows, over the long-term.

These principles guide the direction of the recommendations stemming from these reviews towards achieving the NGO.

E.3 Energy Council Vision and Gas Market Development Plan

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

> “The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established,

and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The Vision is underpinned by four broad policy work streams and related outcomes:[126]

1. **Encouraging competitive supply:**

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

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

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

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

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

   (c) Provision of accurate and transparent market making information on pipeline and large storage facilities operations and capacity, upstream resources, and the actions of producers, export facilities, large consumers and traders.

3. **Improving risk management:**

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

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

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

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

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

4. **Removing unnecessary regulatory barriers:**

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

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

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

E.4 Characteristics of a well functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets.[127]These are:[128]

1. Demand and supply conditions reflected in prices: market participants should have access to a meaningful reference price reflective of underlying supply and demand conditions that usefully aids commercial investment decisions.

2. Timely and efficient investment in infrastructure: efficient additions to, and expansions of, infrastructure enable supply to meet demand while minimising the cost of excess capacity.

3. Readily available market information: efficient outcomes are likely to be achieved when participants (current and potential) have access to clear, timely and accurate information about prices and factors driving prices, such as supply and demand conditions.

4. Price and volume risks can be managed and are appropriately allocated: participants being able to manage operational risks to delivery of physical gas

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

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

while maintaining safe operating parameters, as well as being able to insure themselves adequately against financial risks.

5. Minimised barriers to entry: barriers to entry (and exit) can be a function of market structure, government regulation, industry-specific sunk costs or geography, and certain barriers have the potential to detract from the ability of markets to deliver efficient outcomes.

6. Minimised transaction costs: efficient transaction costs support timely and efficient investments in infrastructure and encourage competition.

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