REVIEW

Australian Energy Market Commission

FINAL REPORT

Review of the Victorian declared wholesale gas market

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About the AEMC

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

Executive summary

The Council of Australian Governments (COAG) Energy Council, at the request of the Victorian Government, asked the Australian Energy Market Commission (AEMC or Commission) to undertake a specific, detailed review of the declared wholesale gas market (DWGM). In accordance with the terms of reference, the purpose of the review has been to consider whether the DWGM:

- allows market participants to effectively manage price and volume risk
- provides appropriate signals and incentives for efficient investment in, and operation of, pipeline capacity
- facilitates the efficient trade of gas to and from adjacent markets
- facilitates upstream and downstream competition.[1]

The Commission has concluded that a number of issues with the existing DWGM arrangements mean that it will not meet all of the Victorian Government's objectives for the market, nor facilitate the achievement of the COAG Energy Council's vision for a liquid east coast gas market.[2]

Recommendations: a staged approach to reforms

In its draft final report, the Commission recommended that in order to meet all the objectives of reform, significant changes were required to the Victorian gas market design. The reform package that was developed is referred to as the "target model".[3]

The Commission continues to consider that the target model is likely to best achieve all the objectives of the review as part of a nationally consistent approach.

However, the target model represented a significant change to the current market, albeit to a design well established in European markets. Designing, testing and implementing the target model is likely to take a few years. This is at odds with the need to reform the DWGM in a timely manner. There are also costs and risks involved with significant market reform of this nature.

Consequently, the Commission is recommending a staged approach to reforms.

Short term recommendations

The Commission recommends a number of incremental reforms which go a long way to achieving the objectives of this review and the COAG Energy Council's vision for east coast gas markets, while being relatively timely and lower cost to implement:

1 The terms of reference are found in Appendix A.

2 The vision is set out in Chapter 1.

3 AEMC, *Review of the Victorian declared wholesale gas market*, draft final report, 14 October 2016.

1. **Provide a cleaner wholesale market price** by including the costs currently intended to be recovered by common and congestion uplift in the market price, while retaining separate pricing of temporal constraints.

2. **Establish a forward trading exchange over the DTS** while retaining the existing daily DWGM.

3. **Improve pipeline capacity allocation and introduce capacity rights trading** by:

   (a) introducing separate, tradable entry AMDQ rights and exit AMDQ rights[4]

   (b) introducing an exchange to improve secondary trading of AMDQ rights (permanent transfer) and benefits (temporary transfer)

   (c) making AMDQ available for a range of different tenures.

Collectively, these recommendations will progress towards the COAG Energy Council's vision for the eastern Australian gas market and address matters raised by the Victorian government in its terms of reference for this review:

- By providing a cleaner wholesale price, market participants will be better able to manage their price risk by entering into physical contracts for gas delivery or financial derivative contracts. In turn, this should stimulate liquidity in these markets, further improving risk management options and providing a transparent reference price on which market participants can make more informed operational and investment decisions throughout the supply chain.

- The introduction of a forward trading exchange should further stimulate liquidity in the physical forward market for gas, improve transparency and reduce transaction costs.

- Improving pipeline capacity rights allocation and introducing capacity rights trading should better enable market participants to manage scheduling risk, and allow for the more efficient allocation of capacity rights between market participants.

- Improving the ability for market participants to manage risk, increasing price transparency, reducing complexity and improving the capacity rights regime should also reduce barriers to entry, encouraging new entrants to the market including those in other states, facilitating inter-jurisdictional trade.

Furthermore, the incremental reforms are consistent with, and are a step towards, both the target model and arrangements in eastern Australian gas markets outside of Victoria.

4 AMDQ are non-firm capacity rights in the DWGM that collectively refers to authorised MDQ and AMDQ cc, discussed in section 4.3.

Longer term recommendation

While the short term reforms go a long way to achieving the objectives of this review and the COAG Energy Council's vision for east coast gas markets, the Commission does not consider that they as fulsomely meet all of the objectives of the reform as the target model.

In the target model, trading of gas would occur on a voluntary, continuous basis, with trading arrangements the same as at the Northern Hub at Wallumbilla. While trading would be voluntary, each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for maintaining system security. Access to the DTS would no longer be allocated through the wholesale market, but instead through a separate capacity market. There would be explicit and tradeable firm capacity rights for entry to and exit from the DTS.

In the east coast review the Commission recommended, and the COAG Energy Council agreed, that the AEMC be tasked to provide a biennial report in growth in liquidity in wholesale gas and pipeline capacity trading markets.[5] Given potential limitations of the short-term recommendations, the Commission recommends that its second biennial review, in 2020, would be an appropriate time to assess the success of the short-term recommendations, the general development of the southern market, and whether more substantial reform towards the target model is appropriate.

Implementation

For each of the short term recommendations, the Commission recommends that the Victorian Government submit a rule change request to the AEMC.[6,7] Acknowledging that the detailed design of each of the recommendations has not been finalised through this review, the AEMC will be able to consider the most effective way to implement the recommendations through the rule change process, in consultation with stakeholders. Under the rule change process, the AEMC is required to make decisions that best meet the National Gas Objective, in accordance with the Commission's statutory decision making process.

The Commission considers the short term recommendations could be implemented in accordance with the indicative timeframes outlined in Table 1 below. We note that the below timelines provide for very little contingency and are reliant on the inputs of multiple parties, including the Victorian government and AEMO. Rule, procedure and system changes may prove to be more time consuming than indicatively provided for below.

5 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 final report, 23 May 2016, pp. 42-43.

6 Rule change requests related to the DWGM must be submitted by either the Victorian Government or AEMO. The NGL is currently being amended to allow any party (other than the AEMC) to submit a rule change request related to the DWGM. However, it has not been finalised at the publication date of this final review.

7 The short term recommendations do not require NGL changes and can be implemented through NGR and procedure changes.

Table 1 Indicative implementation timeframes

Recommendation	Development and submission of rule change request	Rule change	Procedure/system change
1. Cleaner wholesale market price	4 months	Finalised in further 9 months, with draft determination after 7 months	Finalised in a further 18 months from draft determination
2: Forward trading at the DTS	2 months	Finalised in further 6 months, with draft determination after 4 months	Finalised in a further 12 months from draft determination
3: Improving the AMDQ regime	2 months	Finalised in further 9 months, with draft determination after 7 months	Finalised in a further 18 months from draft determination

Context for the review

The declared wholesale gas market (DWGM) was established in 1999 by the Victorian government, with the objective of supporting retail competition and encouraging diversity of supply and upstream competition.

At the time of its establishment, the DWGM had only very limited inter-connectivity with other sources of gas supply and demand. That permitted the market to operate relatively autonomously. However, since then, the construction of an interconnected network of transmission pipelines has linked the DWGM to markets across eastern Australia. This transformation has been accelerated in recent years by the commencement of liquefied natural gas (LNG) exports from Queensland, linking the wider eastern Australian market, including the DWGM, to markets overseas. LNG exports have driven a substantial increase in overall gas demand across eastern Australia, from 709 petajoules (PJ) in 2014 to an expected 1,958 PJ in 2018.[8]

This increase in demand has put upward pressure on domestic prices including in the DWGM, where the average daily price reached a historic high of $9.11 in the first quarter of 2017, double that of 18 months ago.[9]

A further consequence of both the linking of domestic prices to international prices (which are generally linked to oil prices), and the operational characteristics of the LNG industry, has been to increase the volatility of prices. During the more stable market environment of the recent past, DWGM market participants principally managed price risk through long term gas supply agreements (GSAs), with the role of the DWGM largely being to manage daily imbalances in a transparent and competitive manner.

However, the changed market dynamics have prompted a need for greater flexibility in how gas is bought and sold outside of GSAs now and into the future. Consequently, new approaches to managing price risk are becoming increasingly important to participants. The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed and it is these factors that have led to a renewed focus on market development to promote efficient outcomes for consumers.

The existing DWGM will not support achievement of the COAG Energy Council's vision

Over the course of the review, in considering the future role of the DWGM in the market development roadmap the Commission has assessed the current arrangements against the key elements of the vision and, particularly, those attributes highlighted in the terms of reference. The Commission has concluded that a number of issues with the existing DWGM arrangements mean that it will not facilitate the achievement of the COAG Energy Council's vision for Australia's future gas market. The Commission's recommendations reflect the degree to which these issues are undermining achievement of the COAG Energy Council’s vision and the Victorian Government's specified objectives of the review.

Limited risk management options

The DWGM operates as a simultaneous spot market for both gas and access to transportation capacity on the Declared Transmission System (DTS) that underpins the DWGM. Access to the network is allocated dynamically and implicitly to market participants on the basis of bids and offers made for gas on or near the trading day in question. There is no way as part of the DWGM market arrangements to buy or sell gas ahead of the gas day in order to hedge spot price risk.

Furthermore, owing to the complexities of the DWGM pricing mechanism, financial risk management products have not emerged as a means by which market participants can hedge their price risk.

Market participants are therefore only currently able to manage some of the spot price risk by entering into contracts for the physical delivery of gas outside of the DTS, either with producers through GSAs, or through bilateral secondary trades of gas between market participants. Market participants then have to offer the gas they have procured outside of the DWGM into the DWGM to meet their own gas withdrawal requirements, in order to limit any price exposure. These approaches appear increasingly limited in enabling market participants to manage spot price risk.

Opaque longer-term pricing

Market outcomes are in part a function of the quality of information available to market participants. An effective gas market is one that can deliver to participants meaningful, market-based reference prices for gas that reflect underlying supply and demand conditions. Such prices can provide signals to drive the efficient use of gas in the short-term, while promoting efficient levels of investment in physical gas supply and gas consuming-facilities in the long-term.

While the DWGM spot price reflects immediate conditions, it is not representative of supply and demand over the longer term. Long term trades struck outside of the DWGM are negotiated bilaterally, with the terms and price kept confidential. A liquid financial derivatives market would increase the amount of information available to market participants to make informed decisions, but for the reasons discussed above, this has not emerged. Consequently, the existing market arrangements appear unable to support the achievement of this aspect of the COAG Energy Council's vision.

Limited market-driven investment in the Declared Transmission System

While it is currently possible for participants to underwrite investments in the DTS, this tends not to happen because of the "free-rider" problem that arises as a result of the DWGM's design. Access to the DTS is allocated on the basis of DWGM market outcomes and influenced by non-firm capacity rights held by market participants. However, market participants cannot obtain firm access rights which can be exercised regardless of wholesale market outcomes.

The lack of such firm rights to use the DTS means that individual market participants have limited incentives to underwrite investments in the system. Consequently, investment decisions in the DTS are generally the result of a regulatory process, as part of the Australian Energy Regulator's (AER's) review of the pipeline owner's (APA's) DTS Access Arrangement. The regulator and APA are unlikely to have the same information to make efficient decisions compared to a market participant, nor the same incentives to do so, because the risk of those decisions are in large part borne by consumers.

While there are clearly limited incentives for market-based investment decisions, the AEMC’s analysis suggests and stakeholder feedback agrees that there does not appear to have been materially inefficient investment decisions through the regulatory process in practice.

Barriers to trading between markets

There are currently three different facilitated market designs in operation in eastern Australia, with six different pricing points.[10] It is likely that the disjointed nature of these market arrangements is inhibiting trading across the east coast, increasing complexity and transaction costs. These factors may also be deterring participants in one market entering another.

Box 1 Recommendations

Recommendation 1: The Victorian Government submit a rule change to the AEMC to include the costs currently intended to be recovered by common and congestion uplift in the market price, while retaining separate pricing of temporal constraints.

Recommendation 2: The Victorian Government submit a rule change to the AEMC to establish a forward trading exchange over the DTS while retaining the existing daily DWGM.

Recommendation 3: The Victorian Government submit rule changes to the AEMC to improve the existing regime of non-firm capacity rights (AMDQ) by:

1. introducing separate, tradable entry AMDQ rights and exit AMDQ rights
2. introducing an exchange to improve secondary trading of AMDQ rights (permanent transfer) and benefits (temporary transfer)
3. making AMDQ available for a range of different tenures.

Recommendation 4: The COAG Energy Council request the AEMC to assess the southern hub gas market conditions in 2020 as part of the existing biennial liquidity review, and provide recommendations on whether to proceed with implementing the target model.

Contents

1 Introduction

The gas industry on the east coast of Australia is undergoing a structural change. A collection of previously isolated point-to-point pipelines has evolved into a more interconnected network which supports a series of increasingly interlinked markets.

This process has been accelerated by the commencement of liquefied natural gas (LNG) exports from Queensland, which has driven an increase in overall gas demand, the development of new sources of supply and introduced new pricing structures. The shifts in supply and demand, and consequential changes in patterns of gas flows, are impacting market participants and consumers across the east coast, including in facilitated markets such as the Victorian declared wholesale gas market (DWGM). These factors have led to a renewed focus on market development and supply chain efficiency.

Against this background, the Council of Australian Governments (COAG) Energy Council, at the request of the Victorian Government, has asked the Australian Energy Market Commission (AEMC or Commission) to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the DWGM (the DWGM review).[11]

Concurrently, the COAG Energy Council also requested that the AEMC undertake a broader review of the design, function and roles of facilitated gas markets and gas transportation arrangements across the Australian east coast (the east coast review).[12] A final report for this review was provided to the COAG Energy Council in May 2016 and a short explanation is provided at Box 1.2 below.

1.1 Impacts of the east coast gas market transformation on the DWGM

The DWGM is the longest-standing facilitated wholesale gas market in Australia, encompassing the entire declared transmission system (DTS). As illustrated in Figure 1.1, the DWGM is connected to the rest of the east coast gas market, including the large LNG export facilities in Queensland, through a number of interconnected transmission pipelines.[13] The figure shows how the DTS comprises of pipelines extending from Longford in Gippsland in the east of Victoria, across to Portland in the south west, through central Victoria and north to Albury/Wodonga and Culcairn in New South Wales. Other transmission pipelines link the DTS to South Australia (SEA Gas) and the New South Wales south coast (Eastern Gas Pipeline).

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

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

13 A more detailed map of the DTS is provided in Chapter 1 of the final technical report which accompanies this report. See, AEMC, Review of the *Victorian Declared Wholesale Gas Market*, final technical report, 30 June 2017.

Preceding all three short-term trading market (STTM) hubs and the recently implemented gas supply hub (GSH) model, the DWGM is the only virtual hub on the east coast of Australia.[14]

Figure 1.1 The DTS as part of the east coast gas network

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14 A gas hub is a location where the transfer of ownership and pricing of physical gas takes place. At physical hubs, this occurs at a specific location on the pipeline system, while virtual hubs typically encompass a large segment, or all, of a pipeline system.

The DWGM was established in 1999 by the Victorian government with the objective of supporting retail competition and encouraging diversity of supply and upstream competition. Today, the DWGM provides an effective gas balancing service and facilitates a limited amount of trading of gas based on short-term prices.

Retail competition in the DWGM has high customer activity and relatively low market concentration. Two new entrant retailers entered the market in 2014/15 and one new entrant retailer has entered since then, bringing the total number to eleven. Data available on customer switching also suggests customers are actively shipping around between the retailers available.[15]

However, developments in the wider east coast market are now presenting new challenges and exacerbating known issues in the current DWGM market design.

Since 2014, gas consumption on the east coast has increased threefold, driven by LNG exports.[16] This substantial increase in demand has put upward pressure on domestic gas prices. With the first LNG cargoes exported from Gladstone in January 2015, the domestic market is already feeling the effects of greater competition for gas.

Exposure to international LNG prices has increased not only the level, but also the volatility, of domestic gas prices.[17] As many export contracts are linked to international oil prices, there has been a growing trend to link domestic gas prices to oil, presenting a new and unfamiliar risk for all gas buyers to manage.[18] In addition, there is an inherent variability in coal seam gas (CSG) supply, which has in recent years become a significant source of gas and is a key supplier of the LNG export industry. The variability of CSG supply has further exacerbated overall gas price volatility.[19]

Another potential source of increased volatility arises from the operating characteristics of the LNG export industry. In particular, operational incidents relating to the LNG supply chain have the potential to create very large changes in the flows of gas across the east coast. For example, an unexpected shutdown of an LNG processing facility or related infrastructure, or the delay of the arrival of a scheduled LNG export carrier, could result in a large quantity of gas (of an order of magnitude similar to total east coast Australian domestic demand) suddenly and unexpectedly being made available to the domestic market, with CSG wells having only a limited ability to

15 AEMC, *2015 Retail Competition Review*, 30 June 2015, p. 150; AER, *State of the Energy Market 2015*, p. 125; AER, *State of the Energy Market 2017*, p. 138.

16 AEMO, *National Gas Forecasting Report*, 2016.

17 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 36.

18 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, July 2016, pp. 21-22; ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 31-32, 36.

19 Australian east coast coal seam gas production has increased nearly five-fold in the last five years, from 247PJ in the 12 months to June 2012 to 1,214PJ in the 12 months to March 2017. This represents an increase from 35 per cent to 71 per cent of total east coast gas production. EnergyQuest, *Quarterly June 2017 Report*, pp. 75, 105; EnergyQuest, *Energy Quarterly August 2014 Report*, pp. 64, 85; EnergyQuest, *Energy Quarterly August 2013 Report*, pp. 62, 81.

reduce supply in these instances.[20] These incidents are likely to create price volatility across eastern Australian gas markets, presenting both downside and upside risks to market participants.

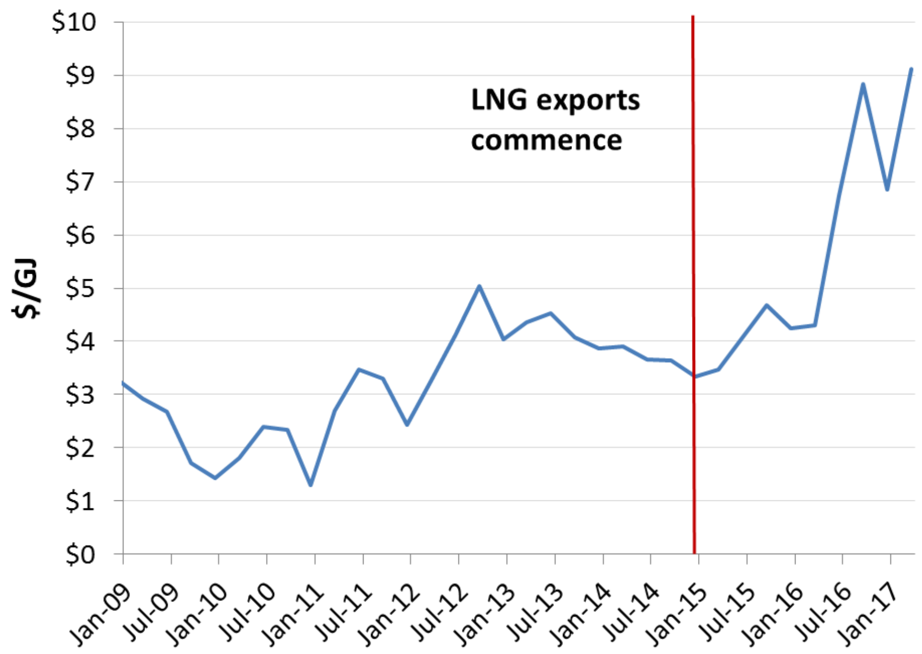
Connected to the rest of the east coast gas market (and ultimately the international market) through interconnected transmission pipelines, the Victorian gas industry is subject to these market forces. The changes to the supply and demand dynamics on the east coast are expected to significantly affect the DWGM in two ways, namely:

1. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with other 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.

2. 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 the factors described above, or when prices make the Victorian market a more attractive alternative.

The effect of the LNG industry on Victorian gas prices is already being observed. Quarterly average daily DWGM prices are at a historic high at $9.11 per GJ in the first quarter of 2017. This has more than doubled in the last eighteen months, as illustrated in Figure 1.2.[21]

Figure 1.2 Price increases in the DWGM

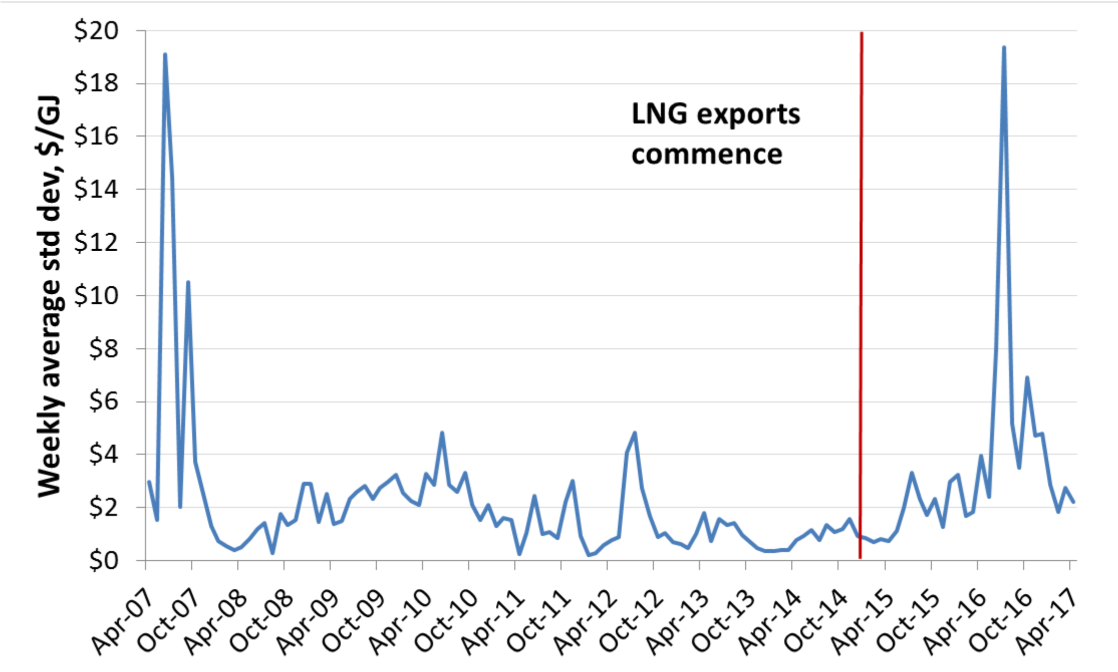


20 PwC estimates the number of shutdowns of LNG processing facilities could be in the range of zero to ten days per year. PwC, *Cost benefit analysis of gas market reforms*, May 2016, p. 54.

21 AER Wholesale Statistics, available at: http://www.aer.gov.au/wholesale-markets/wholesale-statistics/victorian-gas-market-average-daily-weighted-prices-by-quarter.

In addition to increases in the level of prices, the market has also experienced increased price volatility. High price volatility is an important consideration because it tends to increase market participants' exposure to financial risk. Figure 1.3 shows an increase in the variability of prices in the DWGM starting from approximately the time of the first LNG export in January 2015.[22]

Figure 1.3 Price variability in the DWGM beginning of day 6am gas price



As the Queensland LNG industry reaches and maintains full production by 2018, there is likely to be further and sustained increases in the level and volatility of domestic prices.[23]

The transition in the sector has coincided with the expiry of many domestic long-term gas supply agreements (GSAs),[24] raising questions around the DWGM's resilience to

22 The variability in prices was also high in 2007. The Commission understand that this was a consequence of changes to the market design in February 2007 from *ex post* daily pricing to *ex ante* intra-day pricing. The standard deviation in Figure 1.3 is calculated as:

$$\sigma = \sqrt{\frac{\sum_{t=1}^{N_t}(\Delta p_t - \Delta\bar{p})^2}{N_t - 1}}\ , N_t = 7$$

23 In addition, the Commonwealth government has made several announcements related to domestic gas supply that are currently being developed and it is currently unclear how it will affect the market. On 15 March 2017 the Prime Minister announced a "gas supply guarantee" from producers that gas will be available to meet peak demand periods in the NEM. See: https://www.pm.gov.au/media/2017-03-15/measures-agreed-cheaper-more-reliable-gas. On 20 June 2017 the Prime Minister announced that it would regulate gas exports from 1 July 2017, in order to give priority access to domestic customers. See: https://www.pm.gov.au/media/2017-06-20/securing-our-energy-future.

24 Department of Industry, Innovation and Science, *Gas Market Report 2015*, p. 40.

such significant changes. Market participants now require greater flexibility in how they buy and sell gas outside of bilateral gas contracts and new approaches to risk management.[25] The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed.

Box 1.1 Risk management strategies are becoming more important

More flexible and sophisticated means of managing gas portfolios are becoming increasingly important to market participants for the following reasons:[26]

- GSA contract prices are rising due to the **tightening of the supply and demand balance**. While this should incentivise more supply into the market, restrictions and inquiries into gas field exploration and development in several jurisdictions have been inhibiting this response.[27] As a consequence, participants are seeking to source sufficient gas to meet their demand and reduce their average gas supply costs through market-based trading.

- GSAs now tend to have more **restrictive terms and conditions (reduced flexibility)**, in particular with reduced load factor flexibility and/or increases in the cost of flexibility.[28] This may be due to producers seeking to run their facilities at higher capacity to take advantage of increased demand on the east coast, while offering flexibility in GSA's can result in underutilisation of the facility outside peak periods. This is incentivising participants to utilise trading markets to procure flexibility.

- Exposure to international LNG and oil prices has **increased spot price volatility**. Price volatility is likely to provide participants with commercial opportunities to arbitrage gas prices between trading markets on the east coast, or between their bilateral contract price and the spot price. It also makes it increasingly important that participants have the ability to manage the increased price risks on trading markets.

While the DWGM and associated market carriage transportation arrangements[29] are generally considered to have been providing an effective gas balancing service and facilitating some gas trading in Victoria historically, market participants are unable to insulate themselves from the effects of supply and demand changes across the wider east coast.

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25 While customers connected to the DTS have to purchase gas through the DWGM, most retailers and some large customers have long term GSAs, the gas from which they offer into the market.

26 A more detailed description of these issues is provided in: AEMC 2016, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 Final Report, 23 May 2016, pp. 3-8.

27 ACCC, *Inquiry into the east coast gas markets*, April 2016, pp. 65-66.

28 ACCC, *Inquiry into the east coast gas markets*, April 2016, p. 71.

29 The market carriage model, which provides open access to the DTS, uses outcomes from the daily commodity market (the DWGM) to schedule injections to and withdrawals from the pipeline. Access to the DTS is therefore provided through the commodity market (hence "market" carriage).

With potentially large and unpredictable amounts of gas being injected into or withdrawn from the DWGM, it is critical that the Victorian gas market design is sufficiently flexible to accommodate a range of potential scenarios for gas flows and that participants are able to actively manage the risks they face. Ministers at the July 2015 COAG Energy Council meeting noted the "new era of dynamism" in the gas market, and emphasised "the imperative... to get the fundamentals right to prepare market participants for new ways of price discovery, trading, investment and risk management".[30]

1.2 A vision for future gas markets

In light of the above changes, the COAG Energy Council formulated a vision for Australia's future gas market. Released in December 2014, the vision is as follows:[31]

> “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.”

At the present time, gas market arrangements across the east coast of Australia are not consistent with the COAG Energy Council’s vision. The work of the Commission through the DWGM review, as well as the east coast review, has been to develop a roadmap for gas market development that allows the vision to be met. The outcomes of the east coast review are set out in Box 1.2 below.

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

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

Box 1.2 East coast review findings

The east coast and DWGM review have been structured over two stages. The reviews were carried out together in stage one and then split into two separate reviews at the commencement of stage two.

The Commission completed the east coast review in May 2016, with the stage two final report being published on 28 July 2016.[32] In the report, the Commission set out a roadmap for gas market development on the east coast of Australia. Among other things, it included broad recommendations related to wholesale gas markets, including that:[33]

- development efforts be focussed on two primary trading hubs - a northern hub and southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation
- the northern hub be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of optional hub services
- the 'southern hub' be transitioned from the existing DWGM design to continuous, exchange based trading, supported by a system of firm capacity rights
- following these reforms, the STTM hubs be simplified to balancing mechanisms only.

The Commission also made a number of other recommendations in the stage two final report targeted at improving secondary capacity trading on pipelines outside of Victoria and enhancing the information provided to the market through the Natural Gas Services Bulletin Board. The Commission further recommended the establishment of an independent, dedicated group to implement some of these reforms (the Gas Market Reform Group).

While these recommendations were agreed by the COAG Energy Council in August 2016, it was acknowledged that the DWGM review was not yet completed and that "the Victorian government has requested further detailed design work be carried out so that it is in a position to better assess the recommendations".[34] The specific form of the southern hub to be recommended to the COAG Energy Council is the subject of this DWGM review.

32 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, Stage 2 final report, 23 May 2016, Sydney.

33 ibid. Executive summary, p. 14.

34 AEMC, *East coast wholesale gas markets and pipeline frameworks review*, Stage 2 final report, 23 May 2016, Sydney. Executive summary, p. vii.

The vision provides a high level policy statement that has guided the analysis undertaken in this review, focused on key outcomes for the gas market that are necessary to meet the National Gas Objective (Box 1.3).

Box 1.3 The National Gas Objective

The National Gas Objective (NGO) underpins all of the Commission's work and is set out in section 23 of the National Gas Law (NGL). It states:

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

The NGO is structured to encourage energy market development in a way that supports the:[35]

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

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

In accordance with the NGO, the Commission has taken into account the long-term interests of all consumers of natural gas throughout this review. We note that there are numerous types of consumers of natural gas in the Australian economy, including: residential and commercial users; industrial and manufacturing users; gas fired generators; and LNG producers.

1.2.1 The DWGM review terms of reference

The outcomes of the COAG Energy Council's vision are broadly the subject of the Victorian Government's terms of reference for the DWGM review,[36] which is to consider whether the DWGM is achieving the following attributes:

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

36 See Appendix A.

- **Effective risk management in the DWGM:** whether market participants are able to manage price and volume risk and options to improve the effectiveness of risk management activities.

- **Signals and incentives for efficient investment in and use of pipeline capacity:** whether pipeline capacity is being efficiently utilised and allocated to the participants that value it most, whether investment in the DTS will occur in an efficient and timely manner, and options to strengthen the signals and incentives for efficient investment.

- **Trading between the DWGM and interconnected pipelines:** whether the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines, and options to allow producers and shippers to effectively operate across gas trading hubs on the east coast without incurring substantial transaction costs.

- **Promoting competition in upstream and downstream markets:** whether the DWGM continues to encourage the introduction of new gas supplies to the market and promote competition among retailers for the sale of gas, and the extent to which the design of the DWGM may be a deterrent to large users participating in the market.

1.3 The importance of gas market reform

1.3.1 For Victorian gas consumers

AEMO's latest Victorian gas planning report[37] identified that the supply and demand balance in Victoria will continue to tighten and that certain demand growth areas are creating locational pipeline pressure issues. While adequate gas supply is one important aspect for addressing these potential issues, it is also important that the market arrangements are flexible enough to allocate gas to the consumers who value it most, and be responsive to changing consumer needs over time.

Implementing market reforms that achieve the objectives of the DWGM review are expected to ultimately benefit consumers:

- Improving the ability for market participants to manage the price and volume risks associated with trading is expected to place a downward pressure on the costs of providing and using gas. To the extent that this reduces costs for market participants, these cost savings can be passed onto consumers.

- Establishing a reference price that better reflects the value of gas will help to provide market signals to promote the efficient use of gas and efficient levels of investment, throughout the supply chain.

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37 AEMO 2017, *Victorian gas planning report: declared transmission system planning for Victoria*, March 2017.

- Efficient investment in the DTS will help participants to flow gas to where it is needed to meet the needs of gas consumers.
- Streamlining the three gas market designs and moving to a fully integrated east coast gas market will help to reduce the complexity and costs that can discourage greater participation in the DWGM. Reduced transaction costs may result in gas being transported between markets to where it is most valued.

1.3.2 For a national gas market

The reforms to the DWGM are an important piece of the wider east coast gas market reforms being undertaken by the COAG Energy Council, and the achievement of the vision.

Currently there are multiple market designs across the east coast - the gas supply hubs, short term trading market, and the Victorian DWGM. This creates complexity, costs and inefficiencies that discourage greater participation in the markets. Some participants are only registered at the trading markets where they directly consume gas, which limits their ability to trade across the east coast. A fully integrated east coast gas market will provide buyers and sellers with greater opportunity to participate in any of the trading markets in order to improve their commercial outcomes.

For this reason, the COAG Energy Council has agreed to reform the DWGM to create a "southern hub" (see Box 1.2). This would help to align the trading arrangements in Victoria with those across the wider east coast to reduce transaction costs and move gas to where it is most valued. It would also seek to create a southern hub reference price to support the creation of financial risk management tools and inform investment decisions.

The benefits of these reforms to consumers in the national gas market are similar to the benefits to Victorian consumers discussed above.

1.3.3 For electricity reforms

When considering reforms to the DWGM, the Commission is also mindful of the important linkages that exist between gas markets and electricity markets. Gas is a fuel used for electricity generation and a more efficient gas market would make it more efficient to use, or invest in, gas powered generation.[38]

The increased use of gas powered generation in the NEM, at efficient prices and supported by flexible gas trading and transportation arrangements, could provide the following benefits:

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38 For example, a gas powered generator can manage its revenue risk through financial derivatives in the NEM. If the DWGM were improved to better support risk management of gas prices, the gas powered generator would largely be able to fix a profit margin.

- **Potentially placing a downward pressure on electricity prices:** with reduced electricity generation by coal powered plants[39] and a greater proportion of intermittent generators in the electricity mix, gas powered generation (GPG) will increasingly set the market price. Any downward pressure on gas prices resulting from more flexible and efficient trading arrangements is likely to directly affect the costs for GPG and the marginal price at which they offer electricity.

- **Maintaining system security:** gas generation is synchronous, like coal and hydro-powered plants. This provides stability to the electricity network when there are frequency or voltage fluctuations, for example when supply or demand changes suddenly. The shift in the generation mix towards non-synchronous forms of generation such as wind and solar consequently gives rise to increasing challenges in maintaining the system in a secure operating state. As GPG is one of the technologies that can provide these services, the increased use of GPG would be beneficial to system security in the NEM.

- **Ability to balance intermittent output:** wind and solar generation is inherently variable, based on whether the resource is available. Like some other technologies such as batteries, some gas generation technologies can ramp their electricity output up or down quickly to better complement the output of renewable generation. In comparison, coal generation is typically slow to increase or decrease its output, which can result in generation being 'spilled' while a coal generator ramps down, or load having to be curtailed while a coal generator ramps up.

- **Lower emission electricity generation:** gas generation is less carbon intensive than coal generation. In Australia, electricity generation from brown coal emits approximately 1.15 tonnes of carbon dioxide per megawatt hour of electricity generated (tCO2/MWh) and electricity generation from black coal emits approximately 0.9 tCO2/MWh. In comparison, natural gas generation emits on average 0.74 tCO2/MWh. However, certain gas generation technologies are lower emissions intensity than this (such as combined cycle gas turbines which emit on average 0.36 tCO2/MWh).[40,41] Gas is likely to be an important component in an efficient, low cost reduction of emissions for the electricity sector.

39 Two coal fired power stations have closed in the last 18 months. The Northern power station in South Australia closed in May 2016 and the Hazelwood power station in Victoria closed in March 2017.

40 Clean Energy Regulator, Electricity sector emissions and generation data 2015-16. Accessed June 2017 at: http://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/electricity-sector-emissions-and-generation-data/electricity-sector-emissions-and-generation-data-2015-16#Designated-generation-facility-data-201516.

41 Climate Change Authority and AEMC, Towards the next generation: delivering affordable, secure and lower emissions power, June 2017, p. 17.

- **Contributing to the hedge contract market:** hedge contracts act as a form of insurance against fluctuating NEM spot prices and are used to underwrite investment in new generation. With large coal plants exiting the market, there has been a decrease in the availability and competitiveness of hedge contracts. This impacts small retailers and industrial customers who are unable to manage their price risks, and can result in a less competitive industry structure, less competitive pricing, and less reliable electricity supply. Gas powered generators are able to contribute to the competitiveness and liquidity of the hedge contract market.

Having a cohesive set of reforms between the DWGM and the wider east coast will help to realise these benefits from gas generation in the electricity sector. A lower proportion of gas in the electricity generation mix as a consequence of inappropriate reform to the DWGM may make it more costly to achieve the NEM outcomes listed above, or delay the time in which they may be achieved.

1.4 Structure of this report

This is the final report for the DWGM review. The remainder of this document is structured as follows:

- Chapter 2 provides an overview of the DWGM market design features and the identified issues with the DWGM
- Chapter 3 presents an overview of the recommendations for reforms to the DWGM
- Chapter 4 describes the short term recommendations to reform the DWGM
- Chapter 5 describes the long term recommendation to reform the DWGM.

This report also contains a number of appendices:

- Appendix A: Terms of reference
- Appendix B: Assessment framework
- Appendix C: Victorian gas industry structure

This final report is published with two supporting documents:

- a final technical report providing a detailed design of the long-term "target model"
- a final assessment of the alternative market designs that were considered by the Commission.

These documents are located on the AEMC's website.

2 Overview of the current DWGM

As noted in chapter 1, the east coast gas market is undergoing significant changes, which present new challenges for the DWGM and exacerbate pre-existing concerns regarding the market design. This chapter provides a brief description of the design features of the current DWGM, with a focus on those features which are limiting its ability to facilitate the vision. A more comprehensive description of the current DWGM can be found in Stage 1 of the AEMC's east coast review.[42]

An explanation of how the DWGM is limited in its ability to facilitate the COAG Energy Council's vision is then provided in section 2.2 below.

2.1 Overview of the current DWGM design

The DWGM can be considered to integrate three roles into one:

- trading of gas on the gas day
- managing system-wide balancing
- managing gas flows on the DTS consistent with its physical capacity.

These points are discussed below.

2.1.1 Gas trading

The DWGM facilitates the trading of gas by market participants.[43,44] Each market participant is required to submit price/quantity pairs of bids and offers into the DWGM in order to inject or withdraw gas from the DTS for the remainder of the gas day.[45] Based on bids and offers and subject to the pipeline system security limits, AEMO's market clearing algorithm schedules each market participant's injections and withdrawals with the objective of minimising the cost of supplying demand.[46]

Market participants who are scheduled to withdraw more than they are scheduled to inject (they are net short) pay the market price on the quantity of gas they are short. Conversely, market participants who are scheduled to inject more than they are scheduled to withdraw (they are net long) receive a payment of the market price on the

42 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Chapter 6 and Appendix F.

43 Only approximately 20 per cent of gas "traded" through the DWGM is sold from one market participant to another. Approximately 80 per cent of gas "traded" through the DWGM is bought by the same counterparty which sold it.

44 Each participant settles their gas sales and purchases with AEMO, and not directly with each other.

45 More precisely, market participants do not need to bid gas for uncontrollable withdrawals such as for household consumption. Instead, a forecast of uncontrollable demand is automatically "bid" into the DWGM at the market price cap.

46 AEMO, *Technical Guide to the Victorian Declared Wholesale Gas Market*, p. 34.

quantity of gas they are long. These payments are known as "imbalance payments", and in effect are payments for the trade of gas between market participants.[47]

The market price used to settle imbalance payments is set *ex ante* (that is, based on the schedule of gas flows, not on the actual gas flows).

The market price is set in the "pricing schedule", at the price of the most expensive unit of gas that would have been scheduled absent of any physical constraints on the DTS.

The DWGM scheduling process occurs regularly at five pre-defined times within the gas day.[48] For the first schedule of the day, at 6.00am, gas is scheduled for the entirety of the upcoming gas day. Each subsequent scheduling process then revises the schedules for the balance of the gas day, with a new market price set for each schedule. This therefore allows for the trading of gas through the DWGM for the upcoming gas day or for the balance of the gas day.

2.1.2 Managing system balancing

Where market participants fail to meet their scheduled injections and withdrawals, system linepack will increase or decrease to a greater or lesser extent than anticipated, and the system as a whole will become out of balance.

These system imbalances are managed by AEMO through the DWGM scheduling process. In such circumstances, AEMO schedules more or less gas than would otherwise be required in the next schedule (at the next schedule's market price) in order to manage linepack variations in the preceding schedule, with the intention of meeting an end of day linepack target.

The costs or proceeds from this increase or decrease in gas are mostly recovered through payments made by or to market participants who deviate from their previous schedule, commensurate with the impact the market participants had on the system. The payments made by or to deviating parties are consequently known as deviation payments.

Deviation payments are settled at the *ex post* price (that is, at the market price of the next schedule from the one in which the participant deviated) because AEMO is scheduling the appropriate amount of gas in the next scheduling horizon to rebalance the system. This contrasts to imbalance payments, which are settled at the *ex ante* price (that is, at the market price of the current schedule).[49]

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47 "Imbalances" in the DWGM therefore refer to the difference between a market participant's scheduled injections and scheduled withdrawals, and hence result in trades with another market participant. The overall system is not out of balance as a result of trades.

48 Ad-hoc schedules may also occur but only if there are impending or imminent threats to system security requiring urgent action.

49 To be clear, deviation payments are made on deviations between scheduled injections and withdrawals, and actual injections and withdrawals, and are settled *ex post*; imbalance payments are made on imbalances between scheduled injections and scheduled withdrawals, and are settled *ex ante*.

2.1.3 Managing the flow of gas consistent with the physical capacity of the DTS

The DWGM can be considered a form of "virtual" gas hub. Market participants are required to inject and withdraw gas to and from the DTS when scheduled, but it is AEMO which is responsible for the delivery of gas across the DTS. Market participants are not required to transport gas to and from a specific physical point in the DTS in order to trade. Any trading of gas therefore occurs nowhere in particular within the DTS – gas purchases are simply net withdraws from the virtual hub, and gas sales are net injections to the virtual hub.

As the DWGM is a virtual gas hub, it is AEMO's responsibility (as system operator) to manage capacity constraints on the DTS to ensure the physical delivery of gas from injection to withdrawal points. As with system balance and gas trading, this is done through the DWGM scheduling process.

In order for a market participant to inject gas into and/or withdraw gas from the DTS for the upcoming or current gas day, it must offer that gas into the DWGM and/or bid to take that gas out the DWGM.[50]

Market participants must bid/offer their *gross* position in order to be scheduled and gain access from/to the DTS. For example, if a market participant wants to inject 100GJ and withdraw 80GJ, it must offer 100GJ to the DWGM and bid for 80GJ, despite having a *net* position of 20GJ. This leads to a situation where a high proportion of gas "traded" through the DWGM is in reality market participants buying their own gas from themselves.

Market participants are required to bid/offer their gross position because access to the DTS is implicitly allocated through the DWGM. This arrangement is known as "market carriage". Gross offers/bids for gas provide AEMO's market clearing algorithm the information it needs to determine the lowest cost combination of gas to physically schedule to meet demand.[51] Were net positions to be provided to AEMO it would not have sufficient information to physically schedule the system. In this way, the allocation of capacity through the DWGM and the requirement to bid and offer gross gas positions are intrinsically linked design features.

This contrasts with "contract carriage" for access to transmission pipelines in eastern Australia outside of the DTS and in most gas markets globally.[52] Under contract carriage arrangements, access to pipelines is provided to a shipper through a contract with a pipeline owner acquired in a capacity market separate to the commodity market. Market participants *nominate* their gross flows consistent with their capacity

50 In the DWGM, offers to sell gas are known as "injection bids" and bids to buy gas are known as "withdrawal bids". This report will use the term "offers" and "bids" respectively.

51 Strictly, the algorithm determines the lowest *priced* combination of gas to schedule to meet demand, based on market participants' offers. Assuming market participant's offers accurately reflect their costs, then the algorithm efficiently schedules the lowest cost combination.

52 To the Commission's knowledge, the DWGM is unique globally in being a market carriage gas market.

rights. Whether they are provided access to the capacity is determined under the terms of their contract with the pipeline owner, rather than on the basis of their bids and offers for gas. Building on the example above, the market participant would under contract carriage arrangements nominate to inject 100GJ and withdraw 80GJ, and only seek its net position of 20GJ on the market.

As noted above, the market price is set in the pricing schedule assuming no physical constraints on the DTS. Noting that access to the DTS is provided through the commodity market, in order to physically operate the system, AEMO simultaneously runs an "operating schedule" which takes into account the physical constraints on the DTS. In the event of a physical constraint, market participants can be constrained off and not scheduled to inject despite offering gas below the market price. Necessarily, other market participants are constrained on, and are scheduled to inject despite offering gas above the market price (noting that the market price has been set assuming no physical constraints). Under this scenario, physical constraints on the DTS cause costs, because higher cost gas is scheduled as a result of the constraint than would otherwise have been the case.

Ancillary payments are used to compensate market participants that are constrained on, so that in total, the market price plus the ancillary payment equals its offered price for the gas it injects. Absent of ancillary payments, market participants would receive less than their offered price.

Ancillary payments to constrained on market participants are funded through uplift payments, which, to the extent possible, are charged to parties whose actions cause the physical constraint on the DTS which in turn caused the ancillary payments to be incurred. Both market participants and the DTS service provider (APA) are subject to uplift payments. There are three types of uplift payments which a market participant can be subject to:

- **Congestion uplift** seeks to recover costs of "locational constraints"[53] from those that caused them. Congestion uplift charges are levied on market participants who are scheduled to withdraw in excess of their allocated portion of the physical capacity of the system, as defined by their authorised maximum interval quantity (AMIQ), derived from their AMDQ (discussed in box Box 2.2 below). AMDQ therefore provides financial protection against congestion uplift, but this protection is limited because it is not granted if a participant is not injecting gas.

- **Surprise uplift** seeks to recover costs of "temporal constraints"[54] from those that caused them. Surprise uplift charges are levied against market participants whose unexpected actions contribute to the constraint (for example by injecting or withdrawing other than their scheduled quantities, or changing their demand forecast), and hence contribute to the need for higher cost gas to be scheduled. Surprise uplift cannot be hedged, but can be mitigated against through accurate forecasting by market participants.

53 See Box 2.1 for a description of "locational" constraints.

54 See Box 2.1 for a description of "temporal" constraints.

- **Common uplift** charges cannot be allocated to any market participants via congestion or surprise uplift.[55] Clearly, this risk cannot be mitigated nor hedged by market participants.

The DWGM's exclusion of the cost of transportation constraints from the market price contrasts with how prices are set in most other commodity markets (such as iron ore, coal, wheat or the NEM). By exposing all market participants to a price reflective of transportation constraints, all market participants are provided financial incentives to adjust their behaviour (increase supply or decrease demand). This may result in more efficient outcomes than only exposing the notional causers of the constraints to its cost - because parties that would otherwise not be exposed to the cost of the constraints may be able to adjust their behaviour at lower cost than the notional causers of the congestion.

Box 2.1 Temporal and locational constraints in gas transmission

"Temporal" constraints in gas transmission arise because gas does not flow instantaneously. For example, if demand for gas suddenly rises within a part of the DTS, local pressure at that part of the network will fall, which may threaten to exceed safe operating limits. Making a corresponding change to injections from a location very remote from the part of the network with low pressure will not (quickly) address the issue, because the gas from that remote location will take time to arrive. Consequently, more localised action may need to be taken in order to address the pressure issue - constraining on more expensive gas to alleviate the temporal constraint and constraining off more remote but cheaper gas.

Temporal constraints can typically be avoided if AEMO and market participants have good forewarning of upcoming supply and demand conditions across the DTS. If this is the case, AEMO is able to prepare the system, building up pressures in some parts of the DTS in anticipation of future withdrawals, for example. Temporal constraints arise when market participants "surprise" AEMO by changing their gas requirements with insufficient notice for the DTS to have been adequately prepared by AEMO.

Of course, temporal constraints typically do not arise because of nefarious behaviour by market participants. Gas requirements are necessarily uncertain, dependent on a range of unpredictable factors such as the weather or the price in the NEM. Surprise uplift seeks to allocate the cost of temporal constraints to those that surprised AEMO, in order to provide them price signals to forecast as accurately as possible and to trade off the cost of changing controllable demand with the benefits of doing so.

55 For example, costs associated with any excessive AEMO demand forecast overrides. Prior to issuing the pricing and operating schedules, AEMO prepares hourly forecasts for uncontrollable withdrawals based on weather forecasts from the Bureau of Meteorology and compares these with the aggregate demand forecasts provided by all market participants. If they differ, AEMO determines whether to override the market participants' aggregate demand forecasts. See: AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, pp. 45, 86.

The Commission understands that compared to transmission systems in other international markets, the DTS has relatively little linepack (that is, relatively small tolerances for changes in pressure in the system). Consequently, the system is relatively sensitive to unexpected changes in supply and demand.

"Locational" constraints arise when a pipeline does not have the capacity to transport sufficient gas even if there were adequate forewarning of supply and demand conditions. For example, if on a very cold day there is high and sustained demand in Melbourne then the Longford to Melbourne pipeline may be unable to service this demand from the cheapest gas (offered at Longford). This would be the case even if AEMO had ample forewarning of high demand, because it is not able to indefinitely increase pressure in preparation. More expensive sources of gas (for example, from Dandenong LNG or Iona) may be required not because it is close (per se) to the demand, but because it is on the demand side of the constrained Longford to Melbourne pipeline.

Locational constraints can be avoided in large part by building more pipeline capacity. For this reason, congestion uplift seeks to allocate costs related to locational constraints by charging market participants which exceed their AMIQ (related to their AMDQ). The total number of AMDQ available to market participants is set with regard to the total physical capacity of the relevant pipelines.

As with temporal constraints, the creation of locational constraints does not reflect nefarious behaviour on the part of market participants. They have simply offered their gas at a price below the market price and been scheduled as part of the lowest cost combination of gas to meet demand - an efficient outcome in operational timescales, even if it did result in a constraint binding. Over the long-term, market participants could (in theory) underwrite more capacity in order to increase their AMDQ, and hence avoid congestion uplift (as well as reducing the underlying locational constraint). However, for the reasons explained in section 2.2.3 below, market participants are unlikely to underwrite capacity because AMDQ does not provide a firm capacity right, and hence gives rise to a "free-rider" problem for market-led investment.

In the event that two market participants offer or bid gas at the same price but both cannot be scheduled due to a physical constraint, those holding AMDQ rights will be scheduled ahead of those without. In this way, AMDQ offers limited protection from the risk of being constrained off. The amount of available AMDQ rights is set with regard to the physical capacity of the system.

Box 2.2 Authorised Maximum Daily Quantity

In the event of a constraint, market participants which are holders of authorised maximum daily quantity (AMDQ) or AMDQ credit certificates (AMDQ cc) (collectively commonly referred to as AMDQ) are provided financial rights and limited rights to physically access the DTS:[56]

- *Injection tie-breaking rights:* market participants with AMDQ are physically scheduled in preference to those without AMDQ when there are tied injection bids in the DWGM.
- *Withdrawal tie-breaking rights:* market participants with AMDQ are physically scheduled in preference to those without AMDQ when there are tied withdrawal bids in the DWGM.
- *Limited physical protection against curtailment for tariff D sites:* tariff D sites (large industrial and commercial sites) with no authorised MDQ are curtailed ahead of those with authorised MDQ in the first stages of a DTS emergency.
- *Uplift hedge protection:* market participants with AMDQ can create a financial hedge against congestion uplift (described above), provided they inject sufficient gas at the relevant close proximity point.

Authorised MDQ was first allocated at market start and was (and has remained) aligned with the capacity of the Longford-Melbourne pipeline at that time when it was the sole source of gas supply for the DWGM. It is held by tariff D customers (large industrial and commercial sites) and tariff V customers (residential and business loads). In the case of tariff V customers, the benefits of authorised MDQ are assigned to retailers that supply those loads, in proportion to customer numbers. No new authorised MDQ is created.

Since the start of the DWGM, the DTS has been expanded and extended and the new pipeline capacity has been allocated as AMDQ cc to provide similar benefits to those arising from AMDQ on the Longford pipeline. AMDQ cc is held by shippers.

2.2 Emerging issues resulting from the DWGM design

The Commission has identified four key areas of concern with the existing DWGM arrangements that limit its ability to facilitate the COAG Energy Council's vision:

- a lack of transparent and meaningful reference prices, which are important to aid effective short and long term decision-making across the gas supply chain in operations, investment, production and consumption

56 A more detailed description of AMDQ and AMDQ cc is provided in: *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Appendix F.

- an inability to effectively manage risk, which is now particularly important in light of recent and likely future increased volatility in gas flows and prices
- a regulatory framework which does not facilitate market-driven investment in the DTS and instead allocates the risk of network investment decisions to consumers
- trading between hub locations may be inhibited by the significant differences between the DWGM's design and the design of other facilitated gas markets in eastern Australia.

2.2.1 Transparent and meaningful gas prices

Market outcomes are a function of the quality of information available to market participants. An effective gas market is one that can deliver to participants meaningful, market-based reference prices for gas that reflects underlying supply and demand conditions. Such prices can provide signals to drive the efficient use of gas in the short-term, while promoting efficient levels of investment in physical supply in the long-term.

A credible reference price can also be referenced in bilateral contracts. Under these arrangements, while counterparties agree a volume to be delivered over a defined time frame, the price paid on any given day is a function of a floating reference price in a trading market. This reduces transaction costs by making negotiating GSAs simpler, without the need to determine complex pricing formula and undertake gas price arbitrations.

An efficient market-based reference price for gas that is credible in the eyes of participants requires sufficient trading liquidity, to provide confidence that the market price represents the underlying value of gas.

Current market arrangements are unable to deliver a meaningful, market-based reference price for natural gas which reflects underlying supply and demand condition in both the short and long term, and so are unlikely to support the achievement of this aspect of the vision. While the DWGM spot price reflects immediate supply and demand conditions, it is not representative of the longer term. Longer-term trades struck outside of the market (such as GSAs between a market participant and a producer or between market participants) are negotiated bilaterally, with the terms and price kept confidential.

2.2.2 Inability to effectively manage risk

Managing the risk of variations in price

Due to the factors highlighted in chapter 1, gas prices across eastern Australia have become more volatile than they have been historically. As shown by figure 1.3, this volatility has been seen in the Victorian DWGM, which is also seeing spot prices at a historical high. This is likely to become even more pronounced as LNG facilities continue to increase their production.

Efficient markets tend to allow participants to manage the price risks which arise when they have a short or long position in the market.

There are two main ways to manage risks, either through taking a physical position or a financial position.[57] In many mature commodity markets, participants have access to both sets of risk management tools.

Physical positions as a risk management tool

One way to manage a short position in a gas market would be to purchase gas for delivery into the future, but agree the price with the counterparty today. As gas is delivered on future dates, the market participant's requirements will have already been met, and the market participant will not be required to buy or sell additional gas on the spot market at a price which is unknown today. This is known as a physical position.

As a core design feature, the products sold on the DWGM are only a day ahead/balance of day product - that is, the DWGM is a spot market. There is no way, *within the DWGM itself,* to enter into a physical position.

Instead, market participants are currently able to manage some of the spot price risk by entering into contracts for the physical delivery of gas outside of the DTS, either with producers through GSAs, or through bilateral secondary trades of gas between market participants. These contracts are physical positions, in that they allow counterparties to agree the delivery of gas to a location outside of the DTS at a future date at a price agreed today.

Approximately 80 per cent of trading takes place outside of the DWGM/DTS in this way, and has led to most participants aligning their bids and offers in the DWGM to the terms of their GSAs and any other bilateral trades entered into.[58] By offering gas purchased through a GSA or bilateral trade into the DWGM at a very low price (typically the market floor price ($0/GJ)) to meet their own demand, which is typically bid out of the DWGM at the market price cap ($800/GJ), market participants are in balance and hence not exposed to the DWGM market price.

However, there are a number of limitations with this approach regarding how well it enables market participants to manage price risk:

- GSAs appear increasingly insufficient as a tool for market participants to balance their gas supply and demand requirements in order to manage exposure to the DWGM market price. As noted in section 1.1, GSAs that are now being offered by producers tend to have more restrictive and more expensive load factor

57 Market participants can also naturally hedge by becoming vertically integrated (that is, producing and supplying their own gas to meet their portfolio of demand).

58 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, July 2015, p. 119.

flexibility than historically. Market participants are less able to vary the quantity of gas they receive. Conversely, in light of increased gas flow and price volatility, market participants require greater flexibility in order to reduce their exposure to high spot market prices and take advantage of low priced gas for their own use or to arbitrage between markets. Consequently, those with GSAs may nevertheless find themselves having to buy or sell gas through the DWGM to manage supply and demand variability.

- This approach only hedges market participants against a component of their total wholesale gas purchase costs in the DWGM - that related to the market price which is paid in the event that their injections do not match their withdrawals. Market participants which are in balance (injecting and withdrawing the same amount to the DTS) do not face an imbalance payment at the market price, but may nevertheless be exposed to uplift charges.

- While a limited number of bilateral secondary trades outside of the facilitated market do occur, they are typically bespoke, reflecting the needs of the counterparties to the trade. As a result, the Commission understands that the majority of bilateral trades outside of the DWGM are relatively long-term in nature, reflecting the high search and transaction costs to execute trades. For example, not being able to find a prospective counterparty prior to the time of the prospective gas trade taking effect limits the likelihood of otherwise efficient short-term trades taking place. Similarly, having to negotiate terms and conditions (or understand terms and conditions on offer) is likely to limit short-term forward physical trading, both because the transaction cost is disproportionately high in comparison to the value of the gas being traded and because of the time taken to execute the trade.

Financial positions as a risk management tool

In mature markets we would expect market participants to have the capability to enter into financial positions as an alternative to taking physical positions. Financial hedges, for example, allow counterparties to agree today to a financial transaction in the future based on the price of an underlying asset or commodity, such as the DWGM market price. As the value of the financial product is *derived* from the value of the underlying asset, these products are also called "derivatives". While a market participant may be physically out of balance and hence owe (or receive) money from the spot market, their total financial exposure is hedged through this additional financial transaction.

As with the DWGM, the NEM is designed to be only a spot market. An active financial derivatives market has emerged as a "side market" to the NEM, which provides market participants considerable flexibility in the way they manage risk and provides an effective alternative to physical positions.[59]

However, a liquid financial derivatives market has not emerged as a side market to the DWGM. While the Australian Securities Exchange (ASX) has released a number of

59 However, the derivatives market in the NEM is exhibiting reduced liquidity.

such products, no material trading in them has developed.[60] Due to different physical characteristics of gas compared to electricity, the design of the DWGM spot market is in some respects more complex than the NEM spot market. This complexity has not been conducive to the development of a financial derivatives market. In particular:

- As with physical hedging, financial derivative products based on the daily and/or intra-day market prices do not hedge again residual price risk arising from uplift payments.
- The requirement to inject gas to receive congestion uplift protection through AMDQ rights may create an incentive for market participants to take physical positions (that is, inject their own gas to meet their demand) rather than financial positions (that is, not inject their own gas and instead buy gas at the spot price through the DWGM, and hedge the market price risk through a financial derivative).

As a consequence, market participants are unable to effectively manage risks associated with being short or long gas by using financial derivatives.

To summarise, it seems unlikely that liquid physical trading nor the development of financial risk management products can develop in Victoria with the existing design of the DWGM. While this may have been of relatively little consequence during the more stable market environment of the recent past, it will become increasingly costly in a more dynamic market.

Volume risk associated with capacity shortfalls

Market participants face the risk of being constrained off in the event of a constraint, and not being scheduled to inject despite offering gas at a price less than the market price.

AMDQ provides holders a tie-breaking right – when there are equally priced injection bids, market participants with AMDQ are scheduled first. This is particularly useful to a market participant offering gas at $0/GJ to meet its own demand and so avoid exposure to the market price. Because many market participants undertake this risk management strategy, a large proportion of gas is bid at $0/GJ. If there is a constraint such that some gas offered at $0/GJ must be constrained off, those market participants with AMDQ will be scheduled first.[61]

However, if the holder of AMDQ offers at a price higher than a market participant without AMDQ, the AMDQ holder may be constrained off, as a result of AEMO's algorithm which schedules the lowest priced gas to meet demand. For example, a

60 See the ASX website at http://www.asx.com.au/products/energy-derivatives/natural-gas.htm, accessed 1 June 2017.

61 The tie-breaking right applies regardless of whether there is a constraint or not. Without a constraint, two or more market participants may coincidently offer gas at a price *equal to* the market price, in which case market participants with AMDQ would be scheduled ahead of the market participants without.

market participant holding AMDQ and bidding at $0.01/GJ would be constrained off ahead of a market participant without AMDQ offering gas at $0.00/GJ.

AMDQ therefore only offers limited protection against volume risk associated with capacity constraints, which cannot be hedged through other means.

2.2.3 Limited market-driven investment in the DTS

A regulatory approach to investment in the DTS

Investment decisions in the DTS generally result from a regulatory process, as part of the AER's review of APA's access arrangement for the DTS.[62]

Access arrangement reviews tend to occur on a five yearly basis, and involve APA submitting proposed capital expenditure projects to the AER, with supporting information to justify the expense. The AER takes these proposals and any other information it is able to gather into account to assess (*ex ante*) whether the forecast capital expenditure associated with each project is likely to be 'prudent' and meet the test for conforming capital expenditure set out in the national gas rules (NGR).[63]

The AER then determines APA's reference tariffs for the forthcoming access arrangement period to reflect the value of new capital expenditure forecast to occur within the access arrangement period that is reasonably expected to satisfy the requirements in the NGR. However, APA is not obliged to develop the projects it proposed to the AER during the review which formed the basis of the AER's determination.

At the next access arrangement review, the AER considers (*ex post*) whether capital expenditure actually incurred by APA in the previous period was prudent.[64] Any capital expenditure actually incurred but deemed not to be prudent is then removed from the asset base, and so associated costs are not recovered through reference tariffs for the next access arrangement period. This *ex post* review may provide incentives for APA to only undertake investment that had been assessed (*ex ante*) by the regulator to be prudent, and not to undertake investment that it may consider to be prudent but which has not yet been assessed as such by the AER through the regulatory process.

The costs of all investments approved through the regulatory process are currently recovered through volumetric tariffs levied on market participants, with participants passing these costs through to end users.

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62 Investment has been undertaken outside of this regulatory process, for example to support additional flows to Culcairn in recent years. However, in this case, to some extent this investment was able to proceed due to the contractual commitments entered into by shippers on the Moomba to Sydney Pipeline (MSP) side of the Interconnect. If the DTS and MSP had been owned by different parties, this investment may not have proceeded.

63 Rule 79 of the NGR sets out the matters the AER must consider when determining whether or not capital expenditure can be rolled into the capital base.

64 Rule 79 is also used for this assessment.

Why a regulatory approach is required in the DTS

The regulatory approach to investment decision-making contrasts to the market-led approach for all other gas transmission pipelines in Australia, where investment made by pipeline owners is underwritten by market participants through long-term contracts.

In the DTS, the regulatory process to investment decision making is a consequence of a "free-rider" problem associated with the market-led approach. As access to the DTS is allocated on the basis of DWGM market outcomes, market participants cannot obtain exclusive firm access rights. Consequently, a market participant:

- will not be provided access to the DTS if it offers above or bids below the market price (unless it happens to be constrained on)
- may not be provided access to the DTS even if it offers below the market price, in the event of a constraint.

AMDQ do provide some "quasi" physical rights in the form of injection and withdrawal tie-breaking rights, and curtailment protection for tariff D customers. However, these are not firm rights and do not guarantee access. There are also limitations in the way AMDQ is created and transferred which may be affecting participant confidence in its value.[65]

While market participants are *able to* contribute wholly or in part to investment in the DTS, without firm rights to use the DTS, individual market participants have little incentive to do this. Other market participants would also benefit from a capacity expansion, without having contributed to its costs, and may even prevent the funding participant from using it. Market-led investment is therefore stifled under the current arrangements.

The benefits of a market-led approach to investment

The regulatory process for investment decision making has two substantial drawbacks compared to a market-led approach (absent of the free-rider problem which arises from allocating capacity through the DWGM).

Firstly, the regulator and APA are unlikely to have the same information to make efficient decisions compared to a market participant, nor the same incentives to do so, because the risk of those decisions are in large part borne by consumers. The five yearly cycle of determinations has also led to concerns that investment decisions have been insufficiently timely in the past or will react quickly enough to emerging issues. The market-led approach (absent of the free-rider problem arising from the allocation

65 AMDQ is a right from the injection point to the reference hub (Melbourne). Owners can then nominate a different withdrawal point, which is approved by AEMO according to a set of locational factors and system capacity calculations.

of capacity through the DWGM) is therefore likely to result in more efficient and more timely investment decisions.

Secondly, if despite the likely improved decision making under a market-led approach an inefficient investment decision is made, the market participant, rather than consumers, would bear the cost of this decision. Furthermore, as part of an interconnected network, investment in the DTS is increasingly made for the benefit of consumers outside of the DTS, despite the cost and risk being borne by Victorian consumers.

Consequently, the Commission considers that the regulatory approach to investment decision making is in theory a second best alternative to a well-functioning market-led approach. Indeed, it is for these reasons that a market-led approach is preferred outside of the DWGM, where the free-rider problem resulting from the DWGM's design does not exist.

Having said this, the Commission recognises there are a number of provisions in the NGR which aim to address the potential inefficiencies that arise in a regulatory approach to investment decision making. For example:

- Redundant asset provisions allow for assets that cease to contribute in any way to the delivery of pipeline services to be removed from the regulated asset base, and hence the associated costs not recovered from consumers through regulated tariffs.[66] This provides a mechanism by which the risk of inefficient investment is not borne by consumers.

- Investment decisions can be made on a more timely basis than the five year regulatory cycle through AER's power to make advance determination with regard to future capital expenditure.[67]

Furthermore, it is not clear that there have to-date been materially inefficient investment decisions through the regulatory process in practice.

2.2.4 Trading between hub locations

Due to the confidential nature of gas supply agreements across eastern Australia, and gas transportation agreements outside of the DTS,[68] it is difficult to assess the materiality of current trade between the DWGM and other east coast gas markets.

Nevertheless, it is likely that the disjointed nature of market arrangements across eastern Australia is inhibiting trading between locations. There are currently three different facilitated market designs (the DWGM, STTM and GSH) with six pricing points. The complexity for market participants to operate under multiple markets

66 Rule 85 of the NGR.

67 Rule 80 of the NGR.

68 Capacity outside of the DTS is allocated under a "contract carriage" approach whereby shippers contract capacity with pipeline owners.

designs is likely to increase transaction costs, and hence reduce trading between locations.

For those market participants seeking to ship gas across the DTS and onwards (for example from Longford to Adelaide), the requirement to bid and offer gas into the DWGM (despite not actually wishing to trade gas) presents an additional layer of complexity they need to manage. It also requires market participants to incur fees related to the operation of the DWGM. These issues may be inhibiting trade between locations.

In addition, the complexity of the DWGM design is a barrier to entry for some participants that might otherwise enter the Victorian market. For example:

- The pricing and uplift allocation arrangements are complex. New participants are cautious about entering the market where they find it difficult to understand and manage the risks.
- The AMDQ regime involves two types of AMDQ that is owned by different types of participants. There are multiple types of rights attached at AMDQ and not all of these rights can be traded. This complexity, and the difficulties in securing AMDQ through secondary trading, is not conducive for new entrants.

3 A staged approach to reform

3.1 Overview of recommendations

In its draft final report, the Commission recommended that in order to meet all the objectives of reform, significant changes were required to the Victorian gas market design. The reform package that was developed is referred to as the "target model"[69] and has the following attributes:

- trading would occur on a voluntary, continuous basis, with trading arrangements the same as at the Northern Hub at Wallumbilla. The market would be a virtual hub retaining the existing footprint of the DTS
- each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. However, the system operator would remain responsible for maintaining system security
- there would be explicit and tradeable capacity rights for entry to and exit from the DTS. Among other design features, trading would be facilitated through a capacity trading exchange.

The target model is discussed in more detail in chapter 5 and in the accompanying final technical report. For the reasons outlined in chapter 5, the Commission continues to consider that the target model is likely to best achieve all the objectives of the review and is a nationally consistent approach to achieving the COAG Energy Council's vision.

However, the target model represented a significant change to the current market, albeit to a design well established in European markets. Designing, testing and implementing the target model is likely to take a few years. This is at odds with the need to progress the reforms to the DWGM so that its functionality is improved in a timely manner. There are also costs and risks involved with significant market reform of this nature. Furthermore, the Commission acknowledges that existing DWGM users, who are unfamiliar with entry-exit models internationally but are familiar with the characteristics of the Victorian gas market, are currently sceptical of the appropriateness of some aspects of the target model design in the Victorian context. Market participants were particularly keen that the existing market carriage arrangements be retained, and so firm capacity rights should not be introduced.

Therefore it is both prudent and beneficial to take an incremental approach to reform the DWGM. In the short term, the Commission makes a number of short-term recommendations:

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69 AEMC, *Review of the Victorian declared wholesale gas market*, draft final report, 14 October 2016.

1. **Provide a cleaner wholesale market price** by including the costs currently intended to be recovered by common and congestion uplift in the market price, while retaining separate pricing of temporal constraints.

2. **Establish a forward trading exchange over the DTS** while retaining the existing daily DWGM.

3. **Improve pipeline capacity allocation and introduce capacity trading** by:

   (a) introducing separate, tradable entry AMDQ rights and exit AMDQ rights

   (b) introducing an exchange to improve secondary trading of AMDQ rights (permanent transfer) and benefits (temporary transfer)

   (c) making AMDQ available for a range of different tenures.

In time, further consideration should be given to implementing the target model, building upon the short-term recommendations:

4. The COAG Energy Council request the AEMC to **assess the southern hub gas market conditions** in 2020 as part of the existing biennial liquidity review, and provide recommendations on whether to proceed with implementing the target model.

3.2 The benefits of a staged approach to reform

This staged approach has a number of benefits. Firstly, the short term recommendations are likely to be able to be implemented relatively quickly and at relatively low cost. This allows for some of the benefits of the reforms to be realised more quickly than would have been the case with proceeding to the target model in one step. The Commission considers it important to now move from the current phase of reviewing the DWGM to implementing reform.

Collectively, these recommendations will progress towards the COAG Energy Council's vision for the eastern Australian gas market and address matters raised by the Victorian government in its terms of reference for this review:

- By providing a cleaner wholesale price, market participants will be better able to manage their price risk by entering into physical contracts for gas delivery or financial derivative contracts. In turn, this should stimulate liquidity in these markets, further improving risk management options and providing a transparent reference price on which market participants can make more informed operational and investment decisions throughout the supply chain.

- The introduction of a forward trading exchange should further stimulate liquidity in the physical forward market for gas, improve transparency and reduce transaction costs.

- Improving pipeline capacity rights allocation and introducing capacity rights trading should better enable market participants to manage scheduling risk, and allow for the more efficient allocation of capacity rights between market participants.

A staged approach allows the first stage of reform to be implemented and assessed before proceeding with the next stage. Should the short term recommendations be materially successful in improving market participants' ability to manage risk, for example, then the marginal benefits of more substantial reforms may be limited. This may avoid the cost of more substantial reforms.

Secondly, consistency between the short-term recommendations and the target model is expected to help incumbent DWGM participants adjust to certain aspects of the target model, provide learning opportunities to better inform the implementation of further reforms, and reduce the cost, risk and time to transition, should such a transition be appropriate.

Finally, the short term recommendations introduce certain design features that are also consistent with arrangements in eastern Australian gas markets outside of Victoria. For example, the short-term recommendations:

- introduce voluntary forward exchange based trading of gas at the DTS, utilising the same trading mechanism as in the target model and that currently used at the GSHs at Wallumbilla and Moomba
- separate the existing point-to-point AMDQ capacity rights into entry AMDQ rights and exit AMDQ rights, consistent in concept to the firm entry and firm exit rights of the target model
- introduce a facilitated market for capacity rights, consistent with both the target model's capacity trading platform and the capacity trading exchange being developed by the Gas Market Reform Group[70]
- allocate existing AMDQ capacity rights for a variety of tenures, including seasonally, consistent with the allocation of firm capacity rights in the target model.

Greater consistency with arrangements outside of Victoria is expected to reduce transaction costs for market participants operating across the east coast, reduce barriers to entry for prospective market participants more familiar with arrangements outside of Victoria, and reduce the cost of implementing the recommendations by leveraging off reforms that have already been, or are currently being, progressed.

70 The Gas Market Reform Group is developing the implementation approach for a number of recommendations made by in the Commission's east coast review, including those to improve secondary pipeline capacity markets outside of Victoria.

3.3 Benefits of the long-term recommendation

There are some downsides to the incremental approach. While the short term reforms go a long way to achieving the objectives of this review and the COAG Energy Council's vision for east coast gas markets, the Commission does not consider that they as fulsomely meet the objectives of the reform as the target model. In particular:

- Capacity rights in the DWGM (AMDQ) remain non-firm. Consequently, the free-rider problem associated with market carriage described in section 2.2.3 will not be substantially addressed through the short-term recommendations. Market-led investment in the DTS is unlikely to be significantly improved in the short-term. That said, as noted in section 2.2.3, it is unclear whether investment made (or not made) in the DTS pursuant to the regulatory approach has been materially inefficient to-date.
- Participants are not able to manage price and volume risk as well as they could if firm capacity rights were introduced, because they would not have certainty of access to the DTS.
- Trading between jurisdictions may not be as prevalent as if firm capacity rights were introduced, as interstate participants would not have certainty of access to the DTS.
- The short term recommendations introduce forward trading at the DTS, while retaining the DWGM as a separate daily mechanism for trading and balancing on the day. Transaction costs and administrative burden would be further reduced by combining these two markets/processes into one. Furthermore, liquidity in the forward market may be encouraged through the implementation of the target model because market participants would be required to participate in the continuous balancing regime on the day which utilising the same trading mechanism as the forward exchange.
- The target model represents a closer harmonisation of arrangements in Victoria with the wider east coast market compared to the short term recommendations. In particular, the target model introduces:
  - contract carriage with firm capacity rights, which is a feature of arrangements outside of Victoria[71]
  - the same trading mechanism as at the GSHs at Wallumbilla and Moomba both ahead of the gas day and on the gas day.

71 Even with the introduction of the target model, some differences will remain between the Victorian arrangements and the wider east coast market. For the reasons discussed in Appendix E of the east coast review final report, these differences are appropriate. In particular, the Victorian market will remain a virtual hub, meaning that the firm capacity rights are entry rights and exit rights to and from the hub. This contrasts with the point-to-point contract carriage arrangements and physical trading hubs (hubs at a point location rather than over a geographical area) outside of Victoria.

It is for these reasons that the Commission recommends that the target model be reconsidered in the future, to establish whether these issues are material enough to justify its implementation.

3.4 A comparison of the stages of reform

As noted in section 3.2 above, a number of the incremental reforms implement design features consistent with the target model. Table 3.1 below outlines, at a high level, some of the key features of the current DWGM in comparison to those that would be in place were the short term recommendations or target model to be implemented. This table illustrates the progress of reform between the stages.

Table 3.1 Comparison of the stages of reform

Design feature	Current DWGM	Short term recommendations	Target model
Nature of market price	Not reflective of total wholesale price exposure	More reflective of total wholesale price exposure by including the costs currently intended to be recovered by common and congestion uplift in the market price	Reflective of total wholesale price exposure[72]
Forward trading market	Bilateral, opaque and with high transaction costs	Facilitated through voluntary exchange based trading	Same as short term recommendations
On the day trading	Facilitated through the DWGM by AEMO scheduling the lowest cost combination of gross bids and offers for gas to meet demand subject to constraints	Same as current DWGM	Facilitated through voluntary exchange based trading
System balancing	Facilitated through the DWGM by AEMO scheduling more or less gas to meet an end-of-day linepack target	Same as current DWGM	Market participants required to remain in reasonable balance by participating in the voluntary exchange or by adjusting their injections or withdrawals, with the system operator having residual balancing responsibility

72 The target model may also include the equivalent of surprise uplift. See section 3.5 of the final technical report.

Design feature	Current DWGM	Short term recommendations	Target model
Capacity rights firmness	Non-firm AMDQ rights - injection and withdrawal tie-breaking, congestion uplift hedge and physical protection against curtailment	Same as current DWGM although AMDQ would no longer provide congestion uplift hedge as congestion uplift would be removed	Firm capacity rights - market participants nominate injections and withdrawals consistent with their entry and exit capacity and are scheduled. Access to the DTS is not dependent on outcomes in the commodity market
Locational characteristics of capacity rights	Point-to-point rights (AMDQ)	Entry and (separate) exit rights[73]	Same as short term recommendations[74]
Capacity rights trading	Not facilitated	Facilitated through voluntary exchange based trading[75] with outcomes integrated into market systems	Facilitated through voluntary exchange based trading[76] with outcomes integrated into market systems
Tenure of capacity rights	Typically five years	Released over a variety of tenures	Released over a variety of tenures

As can be seen in this table, the key points of reform between stages are as follows:

- The short-term recommendations make the market price cleaner, introduce a voluntary forward exchange for gas and improve various aspects of the AMDQ regime (which remains a non-firm capacity right). On the day trading and system balancing continue to be administered through the existing DWGM.
- The target model:
  - utilises the forward gas trading mechanism introduced through the short-term recommendations for trading of gas on the day itself, replacing the DWGM
  - this in turn requires the introduction of an alternative mechanism to manage system balancing on the day (which is currently achieved through the DWGM). The mechanism used is the same as the forward trading market introduced in the short-term recommendations, with financial

73 Note that these rights are comparable in firmness to the existing AMDQ and that market carriage is retained under the short term recommendations.

74 Note that these rights are firm.

75 Other than for exit capacity for commercial and residential customers where rights would be allocated dynamically.

76 Other than for exit capacity to distribution systems (primarily commercial and residential customers) where rights would be allocated dynamically.

incentives for market participants to trade or adjust their injections or withdrawals to remain in reasonable balance

- replaces the non-firm AMDQ capacity rights with firm and non-firm rights, which should be readily tradable due to the improvements to AMDQ introduced through the short term recommendations.

Table 3.1 above is necessarily a high level overview of the reforms. Chapters 4 and 5 respectively describe the short and long term recommendations in more detail, draw out these comparisons, and provide an explanation of their benefits and stakeholder feedback.

4 Short term recommendations to reform the DWGM

As discussed in chapter 3, the Commission is recommending a number of short term recommendations for reform to the DWGM.

This chapter:

- explains each of the recommendations and their rationale, including stakeholder submissions with regard to the issues and/or recommendations (sections 4.1 to 4.3)
- outlines a number of other actions which might also be undertaken in the short term to progress towards the vision (section 4.5)
- provides details on the AEMC's implementation of the short term recommendations (section 4.6).

4.1 Recommendation 1: Cleaner wholesale market price

4.1.1 Issues

In a virtual hub, all gas in the hub, regardless of its location, is priced the same. The physical characteristics of the transmission network within the hub may influence the price that all gas is traded at, but does not result in the price of gas varying between locations within the hub. A key benefit of a virtual hub is that it pools liquidity around a product which is priced the same for all participants - allowing for market participants to better manage their risk.

The DWGM is typically considered to be a virtual hub. However, it does not exactly conform to the above description. While the *market price* is set the same for all gas in the hub (consistent with a virtual hub), as discussed in section 2.1.3, uplift charges and ancillary payments mean that total wholesale price for gas paid and received by market participants is not the same everywhere and for everyone. The total wholesale price is instead influenced by transmission constraints.

These arrangements mean that the market price is not "clean". The market price does not reflect the total wholesale cost of gas which market participants are exposed to, nor is the same total wholesale price of gas paid and received by all market participants. As discussed in section 2.2.2, this limits the effectiveness of any physical forward position or financial derivative hedges entered into by market participants outside of the DWGM:

- A market participant which is scheduled to inject gas bought outside of the DWGM to meet its own withdrawal requirements will not be exposed to the market price as it is in balance, but may still incur uplift payments.
- Similarly, a market participant which enters into a derivative contract based on the market price may also be exposed to uplift payments even if its exposure to the market price has been hedged.

However, there is a trade-off between a cleaner market price and a desire to encourage behaviour that limits the creation of constraints (and therefore costs) to the system to an efficient level. This trade-off is explored in more detail below.

The trade-off between a clean market price and incentives to limit constraints

As discussed in section 2.1.3, ancillary payments arise due to the cost of DTS constraints not being reflected in the market price. The current arrangements attempt to allocate the cost of constraints to their causers through various types of uplift payments. By allocating the cost of constraints to their causers, the current arrangements attempt to provide financial incentives for market participants to efficiently trade off the privatised costs and benefits of actions which cause constraints, and so:

- only undertake the behaviour which causes the constraint to the extent that it is efficient (that is, the total benefits outweigh the total costs)
- make efficient investments, for example in pipeline capacity or additional LNG capacity in order to receive ancillary payments and hence hedge against the risk of uplift.

Conversely, by socialising the costs of constraints this may result in less efficient management of constraints, including less efficient scheduling outcomes in the short term and less efficient investment in the DTS and other gas facilities in the long-term.

There is therefore a trade-off between cost causality and price cleanliness. On the one hand, exposing all market participants to the same price allows for the better management of price risk, while on the other hand exposing market participants to their specific contribution to the cost of constraints provides incentives for efficient operation and investment. This trade-off of is also seen in the NEM, as described in Box 4.1.

Box 4.1 A comparison with the National Electricity Market

In the NEM the spot price for a region is set for each of the 48 half hour trading intervals in a 24 hour period at that region's regional reference node.[77] This price is set at the point where supply equals demand at that node. Where transmission constraints arise between a node and the regional reference node, this results in a divergence between the notional price at the local node (the price at which supply would equal demand at that node) and the price at the regional reference node.

However, all buyers and sellers of electricity *within* the region pay and receive the same price - the price at the regional reference node - regardless of the notional price at their local node. The local price is not used in settlement. NEM regions are therefore virtual hubs.

This could in theory result in inefficiencies. Market participants are exposed to price signals not reflective of the underlying costs of any transmission constraints between the local and regional reference node. In operational timescales, this could cause them to generate or consume electricity when the cost of doing so is greater than the benefits (or not to consume when the benefits exceed the costs). In planning timescales this could result in inefficient and poorly located investment in generation capacity, load and transmission assets.

However, a single, clean price across the region means that all buyers and sellers are exposed to the same price. This allows market participants to more effectively manage their price risk, and may be a key contributor to the development of the derivatives market in the NEM. Were buyers and sellers to each be exposed to their local price (or sellers exposed to the local price with buyers exposed to the price at the regional reference node), their ability to effectively manage price risk by entering into hedge contracts would be limited. A single market price also serves to pool liquidity and enhance competition within the region.

Given the relatively low level of transmission constraints within regions, the level of inefficiencies resulting from exposing market participants to a clean, single price market is likely to be relatively low. Local prices have not diverged from one another or the regional reference price substantially enough or commonly enough to justify more granular pricing.

Considering the same trade-off *between* regions led the designers of the NEM to a different conclusion. Between regions, transmission constraints are typically greater, meaning that the inefficiencies arising from having a single market price are likely to outweigh the benefits. While there may be relatively low levels of transmission constraints within the states (regions), different regional prices, reflect amongst other things, relatively high levels of transmission constraints between states (regions).

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77 The regional reference node is a location on the transmission network determined for each region by the AEMC in accordance with Chapter 2A of the National Electricity Rules.

The benefits of congestion and common uplift are limited in the DWGM

While the above discussion suggests there may be benefits to recovering the cost of constraints through the uplift mechanism, this is not the case in the DWGM for congestion or common uplift.

Due to the substantial challenges of identifying the specific causers of specific constraints, a number of "rules of thumb" are used to allocate costs between types of uplift, and then to individual participants.[78] These rules of thumb are inevitably imprecise, and at times substantially inaccurate. For example, on 1 October 2016, the Longford facility suffered an outage and was unable to meet production targets, resulting in the need for AEMO to inject out of merit order gas from Dandenong LNG.[79]

These circumstances appear consistent with a surprise-type event, meaning that those parties who were unable to inject should have borne the cost of the ancillary payments. However, we understand that the parties who paid the majority of the uplift were those who had insufficient AMDQ including those parties not operating at Longford and who therefore could not have been said to have caused the shortfall in the conventional sense. Consequently, inaccurate allocation of costs to causers may not be driving market participants to act in an efficient manner.

Conceivably, more sophisticated rules could be designed to allocate costs to causers, but this is likely to result in further complexity. Importantly, however, even if costs were precisely allocated, this would be unlikely to result in more efficient behaviour on the part of market participants in the case of congestion uplift. As discussed in section 2.1.3, AMDQ is not a firm capacity right, and therefore capacity is unlikely to be underwritten by market participants because of the free-rider problem. Even if congestion uplift were sending an accurate price signal to market participants regarding the cost of locational constraints, market participants have limited incentives to respond to those signals. Consequently, the main theoretical benefit of congestion uplift is unlikely to materialise.

Additionally, the congestion uplift regime is complex, which may be acting as a barrier to entry for prospective market participants and creating transaction costs.

Finally with regard to congestion uplift, the AMDQ uplift hedge protection is only activated for a market participant if it physically injects gas into the DWGM. This appears to be creating an incentive for market participants to enter into physical positions outside of the DWGM, rather than entering into financial positions and sourcing their gas in the DWGM.

Common uplift charges are uplift charges that cannot be allocated to any market participants via congestion or surprise uplift and are socialised across market participants. Common uplift charges are not providing accurate price signals to market

78 AEMO, *Technical Guide to the Victorian Wholesale Gas Market*, July 2013, Chapter 15.

79 AEMO, *DWGM Event - Intervention - 1 October 2016*, 14 October 2016.

participants to adjust their behaviours in an efficient manner because of this cost socialisation.

Surprise uplift provides valuable signals

In contrast to common and congestion uplift, the Commission considers that surprise uplift sends important price signals that are relevant for gas market participants to be able to act upon.

Surprise uplift incentivises market participants to accurately forecast (through their bids and offers) their short-term gas requirements, which in turn allows AEMO to prepare the DTS, for example by increasing the pressure in some locations in preparation of future high demand. This is particularly important in gas markets as opposed to electricity markets because gas does not flow instantaneously across the network.

Of course, even with the most sophisticated forecasting tools, market participants may need to change their forecasts or may not inject or withdraw consistent with their schedules. Gas forecasting requirements are inevitably imprecise, and changing forecasts is an everyday occurrence rather than representing nefarious behaviour. Surprise uplift provides market participants with price signals to forecast accurately, and to trade-off the cost of altering controllable withdrawals with the benefits of such behaviour.

While surprise uplift is also imperfect (in that costs are also allocated using rules of thumb), the Commission considers that removing the incentives that surprise uplift provides would be undesirable at this stage. It would likely result in higher cost gas being scheduled more often, with the cost of that gas socialised across all market participants. For example, if surprise uplift did not exist and instead the cost of temporal congestion was reflected in the market price:

- market participants may have more limited financial incentive to accurately forecast their demand and reveal this forecast to AEMO through bids and offers
- AEMO would be less able to prepare the DTS, meaning that more expensive gas would be constrained on more frequently - a productive efficiency loss
- at times of more expensive gas being constrained on in this manner, and given the existing market arrangements, all gas would be priced at the offer price of the most expensive constrained on gas. The market participant which caused the constraint might not be exposed to the market price (if it was in balance and its injections matched its withdrawals) or might even be paid the higher price for gas at Longford (for example) if it was long of gas. All market participants who were short of gas would pay the higher market price - despite not causing the constraint.

4.1.2 Recommendation

In order to provide a cleaner market price while retaining the benefits surprise uplift, the Commission makes the following recommendation:

Recommendation 1:

The Victorian Government submit a rule change to the AEMC to include the costs currently intended to be recovered by common and congestion uplift in the market price, while retaining separate pricing of temporal constraints.

The Commission acknowledges that there are different ways this recommendation could be implemented and will require further detailed work with AEMO to assess the most appropriate implementation path. For example, transmission constraints cannot be readily identified, *ex ante*, as locational or temporal. Low pressure in a pipeline segment, which might be the trigger within the scheduling engine to constrain on gas, might be caused either because a market participant surprised AEMO (that is, a temporal constraint) or because of pipeline congestion (that is, a locational constraint), or both. It is likely to be difficult, therefore, to:

- directly include locational constraints in the pricing algorithm (and hence reflect in the market price the cost of locational constraints currently notionally recovered through congestion uplift), while
- not including temporal constraints (and hence recover these costs through a separate pricing mechanism).

Given these complexities, the Commission suggests that it develops the specific means to implement this recommendation through a rule change process. Furthermore, this specific recommendation arose out of stakeholder feedback on related options outlined in the March 2017 options paper.[80] Developing the implementation details of the recommendation through a rule change process will allow for thorough consultation with stakeholders.

4.1.3 Benefits

By including costs currently recovered by common and congestion uplift in the market price, the market price will reflect a greater proportion of the total wholesale price for gas. This should improve the ability of market participants to **effectively manage risk**.

Market participants entering into forward physical contracts for gas outside the market to match their injections and withdrawals in order to avoid exposure to the market price will now also avoid exposure to the costs related to common and congestion uplift. Similarly, were a market participant to enter into a financial derivatives contract, the market participant's financial hedge against the market price will better hedge

80 AEMC, Review of the Victorian DWGM, *Assessment of alternative market designs*, 30 March 2017, sections 4.1 and 4.2.

against the total cost it incurs. This is the case for both the buyers and sellers of gas through the DWGM, and hence for both prospective buyers and sellers of financial hedge contracts. Improving the effectiveness of financial hedges for both counterparties should increase both the supply and demand of these products.

In turn, improving the effectiveness of physical and financial hedging may improve the liquidity in the markets for these products. This should further enable market participants to manage their price risk, and also provide forward market **price transparency**. Transparent and meaningful forward prices are important to inform market participants when making investment and operational decisions throughout the supply chain from production to consumption.

An additional important consequence of removing congestion uplift is to also make the congestion uplift hedge provided by AMDQ redundant. As noted in section 2.2.2, the current requirement to physically inject gas to receive the congestion uplift hedge when holding AMDQ may be acting as a bias towards physically contracting for gas outside of the DWGM instead of using financial hedges to manage risk. Removing this bias may further stimulate the development of a financial derivatives market as an option for market participants to manage risk.

Improving the ability for market participants to manage risk, increasing price transparency and reducing complexity (by removing some components of the uplift regime) may also **reduce barriers to entry**, encouraging new entrants to the market including those in other jurisdictions.

Of course, retaining separate pricing of temporal constraints will mean that the total settlement outcomes will not be reflected exclusively in the market price. However, for the reasons outlined above, the Commission considers it appropriate to retain incentives for market participants to accurately forecast their gas requirements and to efficiently trade off the costs and benefits of late changes in those requirements. Furthermore, the risk to market participants of incurring charges to fund ancillary payments as a consequence of temporal constraints is manageable through better forecasting and choosing, where it is possible and efficient, not to adjust their gas requirements.

Adopting this recommendation could be expected to lead to more volatile DWGM price outcomes than at present because binding locational constraints will influence the market price. However, this option (and recommendation 2 discussed below) better enables market participants to manage this volatility. The NEM is a highly volatile market, but the presence of a liquid financial derivative market means that this volatility can be managed by market participants.

4.1.4 Other considerations

This recommendation would be expected to result in a wealth transfer from buyers of gas in the DWGM to sellers of gas, which we would expect would ultimately be passed to consumers, increasing prices in the short term. This is because all gas in the market would be priced reflective of locational constraints, rather than just the constrained on gas.

However, the current arrangements may be resulting in inefficiencies to the long-term detriment of consumers, which is inconsistent with the National Gas Objective. Under the recommendation, all market participants, not just those exposed to congestion uplift, would be provided equal financial incentives to alleviate the constraint. This is consistent with other commodity markets which reflect the cost of transportation in the price of the commodity. Market participants not currently exposed to the cost of locational constraints may be able to curb their withdrawals or raise their injections at lower cost and hence more efficiently (assuming they were provided with sufficient information about the ongoing supply and demand for gas within a schedule to make any adjustments) if they are exposed to the price signals.

To the extent this wealth transfer was likely to be significant, it could be reduced or offset if combined with a reduction in the market price cap and/or the cumulative price threshold. Further consideration would be given to this matter through the rule change process.

4.1.5 Stakeholder submissions

Stakeholder submissions on this topic were in general agreement that there is an issue with the market price and uplift payments, and supported seeking a cleaner market price and/or simplifying the uplift payment regime. However, there were varied views on the best way to achieve this. Stakeholders put forward a range of ideas from socialising more of the uplift charges, to removing uplift entirely and reflecting all transmission constraints in the market price. These views are described further below.

Congestion uplift

Stakeholders generally considered that congestion uplift, as it is currently applied, is not providing value in the DWGM and should not be allocated to the notional causers of that uplift.

AEMO noted that the type of constraints congestion uplift was originally envisaged to address (system wide demands exceeding the capacity on pipelines) is no longer a significant issue in the DTS. On the other hand, congestion due to maintenance or outage is more likely to occur now, but in those circumstances congestion uplift is unlikely to allocate cost to cause. AEMO noted that the system event on 1 October 2016 illustrates this issue. AEMO also noted that congestion uplift is difficult for participants to hedge and therefore a difficult risk to manage.[81]

Some other stakeholders raised particular issues that they would like addressed through the DWGM reforms:

81 AEMO, Submission to the assessment of alternative market designs, Appendix A, pp, 2-5.

- Origin considered that participants should not be required to inject gas to receive congestion related ancillary benefits (such as the congestion uplift hedge attached to AMDQ). Origin noted that removing the link between AMDQ and uplift payments means a retailer could enter into a derivatives contract with a shipper holding AMDQ injection rights, and the retailer would have certainty of the price at which it could withdraw that gas.[82]

- ENGIE raised concerns that a constraint on flows from Port Campbell to Melbourne on the South West pipeline unnecessarily prevents gas from being scheduled between willing gas suppliers and buyers at the Port Campbell node. ENGIE believes this is in part due to the separate pricing and operating schedules.[83]

Surprise uplift

On the other hand, a number of stakeholders considered surprise uplift plays an important role and should be retained. This is because it provides an incentive for participants to forecast accurately and to not deviate from scheduled injections and withdrawals.[84] EnergyAustralia was in strong agreement that surprise uplift should not be removed, because reducing the penalty for those who deviate from forecasts is likely to compromise the reliability and security of supply.[85]

Stakeholders views on options to incorporate uplift into the market price

As the AEMC's specific recommendation arose out of stakeholder feedback on related options outlined in the March 2017 options paper,[86] no formal stakeholder feedback has been provided on the AEMC's specific recommendation. Nevertheless, stakeholders provided a variety of views in response to the March 2017 options paper on options to improve or remove the uplift regime.

EnergyAustralia and AGL supported the proposal in the current pending rule change request on the application of constraints in the DTS.[87] EnergyAustralia considered that introducing constrained pricing for injections may result in increased market prices. On the other hand, introducing constrained pricing only for withdrawals (as per the rule change request) would reduce the risk that an injection offer below the market price is not scheduled but withdrawals are exposed to the market price.[88] AGL agreed that aligning the pricing and operating schedules to reflect withdrawal constraints, but retaining separate schedules, will resolve some of the concerns with the current DWGM.[89]

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82 Origin, Submission to the assessment of alternative market designs, p. 6.

83 ENGIE, Submission to the assessment of alternative market designs, p. 3.

84 AEMO, Submission to the assessment of alternative market designs, Appendix A, p. 5.

85 EnergyAustralia, Submission to the assessment of alternative market designs, p. 4.

86 AEMC, Review of the Victorian DWGM, *Assessment of alternative market designs*, 30 March 2017.

87 AEMO, Rule change request, Application of constraints in the declared transmission system, 24 November 2016.

88 EnergyAustralia, Submission to the assessment of alternative market designs, p. 3.

89 AGL, Submission to the assessment of alternative market designs, p. 3.

Origin supported the inclusion of *all* uplift charges into the market price, effectively combining the pricing and operating schedules and including both locational and temporal constraints in the derivation of the market price (transmission constrained pricing). It considered that having a single commodity price would facilitate the development of risk management products. It noted that the price of gas would better reflect demand and the actual value of gas. It also considered that exposing all participants to the same market price would improve allocative efficiency.[90]

ERM also supported this option in principle, as it considered that capturing the risks and costs in a clean market price would facilitate financial derivative products. However, ERM's support was subject to further analysis on pricing and bidding behaviour to ensure the model does not provide opportunities for gaming that could result in significant and consistently higher prices, unintended wealth transfers, or increased costs to consumers.[91]

AEMO did not support the transmission constrained pricing option (that is, including all uplift charges in the market price) as it introduces additional pricing risks to the market, which it considered may make it more difficult to hedge. AEMO was also concerned that the market price is likely to be set by LNG owners, as the marginal provider of gas, which is likely to increase the price and volatility. AEMO raised similar concerns to ERM around the exercise of market power and the risk of gaming (as did MEU),[92] and suggested that if this option were pursued, the market's pricing parameters should be completely reviewed as well as introducing good faith provisions for intra-day re-bidding.[93] Origin agreed that it would be prudent to periodically review the market price cap and cumulative price threshold, similar to the NEM.[94]

Instead, AEMO suggested an option that retains the current categories of uplift, except congestion uplift would be socialised across all market participants (that is, incorporated into common uplift). Surprise uplift would remain cost to cause.[95]

AER agreed that constraints and uplift management should be investigated, particularly given the ancillary and uplift settlement outcomes from the significant price event at Longford on 1 October 2016. It noted that AEMO may consider whether there is scope for improving the allocation of uplift payments, and encouraged that examination.[96]

90 Origin, Submission to the assessment of alternative market designs, pp. 4-5.

91 ERM, Submission to the assessment of alternative market designs, pp. 4, 5, 7.

92 MEU, Submission to the assessment of alternative market designs, p. 13.

93 AEMO, Submission to the assessment of alternative market designs, Appendix B, pp. 1-2.

94 Origin, Submission to the assessment of alternative market designs, p. 4.

95 AEMO, Submission to the assessment of alternative market designs, Appendix A, pp. 2-5.

96 AER, Submission to the assessment of alternative market designs, pp. 9-10.

4.2 Recommendation 2: Forward trading platform

4.2.1 Issues

As discussed in section 2.2.2, DWGM participants are unable to manage price risk through the DWGM itself as it is a spot only market. Typically, market participants enter into long term supply contracts outside the DWGM to manage risk, either directly with producers or on the secondary market with other market participants.

GSAs struck with producers are becoming increasingly inflexible and do not allow participants to adjust their requirements, and are typically for relatively large quantities of gas and so are less suitable for smaller market participants or new entrants.

Secondary trades of gas between market participants allow them to manage their portfolio, but are not readily entered into because of the high search and transaction costs and the time required to negotiate is prohibitive. Furthermore, trades outside the DWGM are bilaterally negotiated and are not reported, so do not reveal a transparent reference price. This in turn may be adding to high transaction costs, as market participants are unable to readily identify an appropriate price at which to trade gas.

4.2.2 Recommendation

To address the high transaction costs in the forward physical market, and to increase price transparency in that market, the Commission makes the following recommendation:

Recommendation 2

The Victorian Government submit a rule change to the AEMC to establish a forward trading exchange over the DTS while retaining the existing daily DWGM.

Under this recommendation, access to the DTS would continue to be market carriage. Participants would bid and offer gas into the DWGM on a daily and intra-day basis and be scheduled by AEMO, as they do today.

However, to manage price risk participants would be able to enter into trades ahead of the gas day through a voluntary exchange, such as the Trayport exchange used at the gas supply hubs. This would enable participants to agree in advance to a price for a particular quantity of gas and delivery date(s). Products with a range of suitable tenures could be developed (daily, weekly, monthly, seasonal) and participants could enter multiple forward trades in the lead up to the gas day to adjust their position. However, unlike the gas supply hub design[97] or the target model, participants would not be able to trade on the day through the exchange. Instead, on the day trades, and access to the DTS, would continue to be through the daily and intra-day DWGM process.

97 The gas supply hubs include a 'balance of day' product that allows trading on the day.

At the start of the gas day, the net forward position of exchange trades for each participant would be integrated with the DWGM process and become part of the participant's delivery or receipt obligation at the 6am schedule. A market participant could meet its forward trade positions by either:

- bidding or offering gas and being scheduled into the DWGM
- relying on the market to meet its forward position and receiving or paying the spot price:
  - This might occur because the market participant has insufficient gas outside of the market, or because it is not scheduled through the DWGM process due to a constraint.
  - Alternatively the market participant might choose this outcome deliberately if the market price was above or below a certain amount, by making an offer/bid into the DWGM above/below that price. This would in the case that they would rather purchase/sell gas on the spot market (at the market price) rather than inject/withdraw gas.

Market participants would be free to continue to source some or all of their gas:

- outside of the daily DWGM or forward exchange, for example through long-term GSAs, and offering this gas into the DWGM in order to gain access to the DTS on the day
- through the DWGM spot market.

Settlement

Trades in the forward market would impact DWGM settlement. The quantity of gas on which market participants incur imbalance payments at the market price would be adjusted by their net forward positions. Imbalance payments (which may be negative or positive) in the 6am schedule would now be calculated as follows:

> Imbalance payment = ((scheduled withdrawals - scheduled injections) - net pre-agreed quantity)) x market price

Market participants could avoid exposure to the market price by meeting their forward position by being scheduled, or put another way, by participating in the DWGM such that their net forward position matches their net injections/withdrawals.

Trades through the forward exchange would be settled at the pre-agreed price. Consequently, total settlement outcomes would be as follows:

> Revenue = pre-agreed price x pre-agreed quantity[98]
>
> + ((scheduled withdrawals - scheduled injections) - net pre-agreed quantity)) x market price

98 If the market participant enters into multiple forward trades, the revenue from each trade would be calculated separately.

If a market participant does not participate in the forward market then its pre-agreed quantity is zero, and the equation simplifies to the familiar current imbalance payment formula for the 6am schedule:

Revenue = (scheduled withdrawals - scheduled injections) x market price

Take the example in Table 4.1 below. On the exchange ahead of the gas day, participant A sells 100GJ to participant B for $6/GJ for delivery on the gas day. On the gas day:

- Participant B's net forward position is integrated with the DWGM. It bids and is scheduled to withdraw 100GJ. Therefore it has zero imbalance (taking into account its pre-agreed trade position) and it is not exposed to the market price.
- Participant A's net forward position is integrated with the DWGM. It offers and is scheduled to inject 90GJ because it does not have sufficient gas outside of the DWGM (for example). Therefore it has an imbalance of 10GJ compared to its net forward position, which is purchased at the market price of $8/GJ.
- Given participant A's imbalance position of 10GJ, the DWGM is scheduled to supply this demand collectively from the remainder of the market participants at the $8/GJ market price.

Table 4.1 Balancing settlement and quantities with forward trading

	Participant A			Participant B			Remainder of DWGM participants		
	Vol. (GJ)	Price ($/GJ)	Settlement ($)	Vol. (GJ)	Price ($/GJ)	Settlement ($)	Vol. (GJ)	Price ($/GJ)	Settlement ($)
Net pre-agreed quantity (X)	-100	6	-$600	100	6	$600	0	-	$0
Scheduled withdrawals - scheduled injections (Y)	-90	-	-	100	-	-	-10	-	-
Imbalance (Y - X)	10	8	$80	0	8	$0	-10	8	-$80

The following outcomes should be noted:

- The total net amount of gas physically scheduled (the sum of row Y) is zero. That is, the system is physically in balance.
- The total settlement outcomes also balance to zero. That is, participant A has received a total of $520, B has paid $600, and the rest of the market has received $80.

- By being scheduled the same amount as its net exchange trading position, participant B was not exposed to the DWGM market price. In effect, it was able to lock in its price ($6/GJ) on the exchange ahead of time, allowing it to manage its risk.
- Participant A was exposed to the market price on the gas it was short in getting scheduled into the DWGM.

Imbalance payments on schedules other than the 6am schedule would continue to be calculated as currently. Deviation payments would also be unaffected and would be made on the difference between scheduled injections and withdrawals, and actual injections and withdrawals.

Box 4.2 Examples in the forward market

Example 1

Market participant A owns a factory and has pre-agreed a price for gas delivery with a counterparty through the exchange. On a particular day the factory has an unexpected shutdown and cannot use gas. Participant A's net forward position to receive gas that day is integrated with the DWGM. However, participant A does not bid into the DWGM and is not scheduled to receive the gas. Consequently it receives an imbalance payment,[99] effectively selling the gas it has 'pre-bought' back to the market at the DWGM market price. Participant A recoups some of the value of the pre-agreed trade, or could even profit if the market price exceeds the forward trade price.

Alternatively, market participant A knows in advance of an upcoming scheduled shutdown. It may choose to sell its gas in advance through the exchange, and hence fix in advance the amount of value it recoups from its original pre-agreed trade. Its net position going into the gas day will be zero, and hence it will not be exposed to the market price.

Example 2

Market participant B is a shipper in another jurisdiction who wishes to sell gas into the DWGM. Participant B entered into a forward trade on the exchange to secure a price for its gas. On the gas day it offers the pre-agreed quantity of gas into the DWGM and is scheduled. As its net forward position has been scheduled, participant B is in balance and not exposed to the DWGM market price.

If market participant B offers the pre-agreed quantity of gas into the DWGM but is not scheduled (for example because its offer price is above the market price or there is a constraint) it will incur an imbalance payment, effectively buying the gas it has 'pre-sold' from the market at the DWGM market price. This scheduling risk can be managed to some extent by securing AMDQ and offering gas at $0/GJ, discussed at section 4.3 below.

99 An imbalance can be positive (the participant incurs an imbalance payment) or negative (the participant receives an imbalance payment).

4.2.3 Benefits of forward trading at the DTS

Improvements to forward trading, in particular the facilitation of shorter term trades, is expected to give DWGM participants more options to **manage price risk** and hedge their positions ahead of the gas day.

In addition, exchange trades would be **transparent**, which would allow the development of a forward price for gas at the southern hub.[100] At the moment, GSAs and secondary trades are carried out bilaterally and are not transparently reported to the market. Over time, participants would be able to use a transparent reference price as the basis for a variety of operational, production and consumption investment decisions.

Not having a forward trading platform may have been discouraging new entrants outside the DWGM who may only occasionally want to participate in the market. The use of a trading platform such as Trayport will provide a significant degree of consistency between the DWGM forward market and forward markets at other trading locations across the east coast which should encourage **greater levels of trade across jurisdictions**. Products could be developed across locations, such as spread products and swap products, which may also encourage greater levels of inter-jurisdictional trade.

Trayport is also expected to reduce the administrative burden and transaction costs of trades. In particular, this may make lower value trades more economical (as the transaction cost is fixed and therefore disproportionately high for low value trades). It should also allow for trades to be executed more quickly, improving the ability to execute trades of a more immediate nature or for a shorter duration.

The Commission has considered whether it is appropriate to create a forward trading location at one or more locations outside of the DTS (such as Longford), to better facilitate secondary bilateral gas trading.[101] However, the Commission considers that there are the following benefits of locating the forward trading at the DTS:

- Liquidity is maximised as participants can enter forward trades with each other from any location across the DTS. In contrast, multiple trading locations would split liquidity and may mean that some locations are difficult to access for some market participants.
- It may encourage more producers or shippers to enter forward trades at the DWGM. To the extent that it encourages new entrants into the market, this may improve competition.
- It allows net forward trade positions to be integrated with the DWGM. This is expected to reduce administrative burden and transaction costs for participants.

100 AEMO p. B4 - trades at physical locations outside the DTS could be accommodated as 'off market trades' and be registered and settled through the market. This would assist transparency of these bilateral trades.

101 This was canvassed in the March 2017 options paper: AEMC, Review of the Victorian DWGM, *Assessment of alternative market designs*, 30 March 2017.

- There is no counterparty delivery risk for those entering exchange trades. This is because if a participant is not scheduled in the DWGM (either intentionally or due to a constraint) to meet their forward position, the DWGM process satisfies the forward position through the spot market.[102]

4.2.4 Stakeholder submissions

In discussing incremental improvements to the DWGM, stakeholders were generally in agreement that improvements to forward trading would provide participants with greater flexibility to trade day ahead and other short term products, improve opportunities for cross market trade by aligning the market with the other gas supply hubs, and improve price transparency.[103] This was also considered to be a relatively low cost option, given a trading platform could be conducted on Trayport.[104]

Most stakeholders also agreed the exchange should be located at the DTS for the following reasons:

- it maximises liquidity by pooling buyers and sellers over the DTS[105]
- it maintains a single price reference point and trading location, instead of forward reference prices being from a location outside the DTS[106]
- there would be no counterparty risk (unlike trading at Wallumbilla) because the DWGM process provides for delivery.[107]

MEU considered there would be minimal, if any, downside to having a voluntary forward trading exchange within the DTS.[108]

Some stakeholders noted a preference that net forward trades should not be automatically bid or offered into the DWGM. Instead they suggested (as the Commission has recommended) that participants should be able to choose whether to meet their pre-agreed trades by physically injecting or withdrawing gas, or by purchasing or selling gas at the spot price. This gives participants more flexible options in managing their position.[109]

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102 This contrasts with the situation at the Wallumbilla gas supply hub. If a participant defaults on a gas delivery by more than five per cent of the delivery obligation (for both over and under-delivery), the defaulting party is required to compensate their counterpart. The defaulting party must pay 25 per cent of the value of the variation quantity to their counterpart.

103 Submissions to the assessment of alternative market designs: Origin, p. 5; EnergyAustralia, p. 3; Shell, p. 2.

104 AGL, Submission to the assessment of alternative market designs, p. 11.

105 Submissions to the assessment of alternative market designs: AEMO, Appendix A, pp. 9-10; EnergyAustralia, pp. 2-3.

106 Submissions to the assessment of alternative market designs: AER, p. 10; AGL, p. 11.

107 AEMO, Submission to the assessment of alternative market designs, Appendix A, pp. 9-10.

108 MEU, Submission to the assessment of alternative market designs, pp. 16-17.

109 Submissions to the assessment of alternative market designs: ERM, p. 5; AGL, p. 11.

Jemena and Origin preferred that a trading exchange be located outside the DTS. For example, trading at Longford would provide a price at the three main production zones (Wallumbilla, Moomba and Longford).[110] In contrast, Shell, which has a portfolio of gas in north eastern Australia, considered that if physical trading outside the DTS was implemented, Culcairn, to the immediate north of the DTS would be a good location.[111] The Commission considers that participants appear to support trading locations outside the DTS to meet their individual trading needs. As noted by AEMO, this would likely split liquidity and there may be less confidence that the price at those trading locations reflects the demand conditions.[112]

4.2.5 Outstanding design features

While section 4.2.2 outlines the recommended design of the trading platform in general terms, there are a number of outstanding design features still to be finalised in the rule change process and any procedures developed by AEMO. These include:

- the management of credit risk, including the timing of settlement for pre-agreed trades (for example, at the time of trade or on the gas day), and prudential requirements
- whether participants in the forward exchange would have to be registered participants to the DWGM
- the products to be included on the exchange, including their start dates and tenure, and whether any spread/swap products with those on the Wallumbilla or Moomba hubs would be valuable
- the process by which additional products would be added to the exchange over time (or existing products removed)
- whether and how forward trades made outside of the exchange could be voluntarily integrated in the DWGM for the gas day.

AEMO would also need to determine its requirements to hold an Australian financial services licence, or seek an exemption.

Further design features not identified in the list above are likely to emerge during the rule change process, discussed in more detail in section 4.5.

110 Jemena, Submission to the assessment of alternative market designs, p. 5.

111 Shell, Submission to the assessment of alternative market designs, p. 2.

112 AEMO, Submission to the assessment of alternative market designs, Appendix B, pp. 4-5.

4.3 Recommendation 3: AMDQ improvements

4.3.1 Issues

The existing AMDQ regime (including authorised MDQ and AMDQ cc) is causing the following issues for DWGM participants and potential new entrants:

- AMDQ do not provide firm capacity rights. This can reduce the incentive for market-led investment. For these reasons, most of the investment in the DTS occurs through the regulatory process:
  - Market led investment in DTS capacity to create new AMDQ is susceptible to free-riding, because the DWGM provides open access (subject to the tie-breaking and curtailment rights).
  - Participants may not be able to nominate newly acquired AMDQ to their preferred withdrawal point, even if they have underwritten the investment, should another participant nominate their AMDQ to that withdrawal point first.[113]
- The AMDQ regime is complex. These complexities are making it difficult for both existing DWGM participants and potential new entrants to understand and use AMDQ:
  - There are two different types of AMDQ: authorised MDQ, which is owned by consumers and relates to capacity on the Longford to Melbourne pipeline; and AMDQ cc, which is owned by market participants and relates to DTS capacity that has been built since market start.
  - AMDQ provide a number of different rights: injection tie-breaking rights; withdrawal tie-breaking rights; uplift hedge for congestion; and curtailment rights in emergencies.
- There are issues restricting the ability of market participants to trade AMDQ:
  - Authorised MDQ at Longford for tariff V customers is dynamically allocated to retailers based on customer numbers, and cannot be traded. Therefore, the participants with authorised MDQ rights may not have gas to inject at Longford (because they are sourcing their gas from another location) despite notionally holding capacity related to the Longford to Melbourne pipeline.[114]

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113 The requirements that a participant must have contracted capacity on an adjoining pipeline to secure AMDQ at that point goes some way to addressing this issue, but some of the adjoining pipelines have more contracted capacity than there is inside the DTS. This is discussed in greater detail in the March 2017 options paper: AEMC, *Review of the Victorian DWGM*, Assessment of alternative market designs, 30 March 2017.

114 Where a retailer with authorised MDQ is not in a position to inject gas at Longford (that is it cannot get a congestion uplift hedge due to injection limitation), they can arrange an Agency Injection Hedge Nomination with another participant that does have injection capability at Longford. This provides the retailer with authorised MDQ with a congestion uplift hedge and the participant with injections an additional quantity of authorised MDQ for injection tie breaking. However, an

- — The processing time for AMDQ trades is lengthy at around six business days. This is prohibitive for shorter term trades.
- — Search and transaction costs are high. Participants must find each other bilaterally to trade.
- — AMDQ are created or obtained as a point-to-point right between the injection point and the reference hub (Melbourne). Participants can then nominate a different withdrawal point, subject to "locational" and "diversity" factors. A participant currently does not have any guarantee, when they obtain AMDQ, that it will be able to transfer the withdrawal tie-breaking rights to its preferred location.

- AMDQ are conservatively calculated. They are provided for long periods of time (five years or in perpetuity), so to guarantee the system can support the AMDQ under normal operating conditions, the maximum that can be released will necessarily relate to forecasts of the lowest capacity available over the five year period.

4.3.2 Recommendation

To address these issues with the DWGM the Commission makes the following recommendation:

Recommendation 3:

The Victorian Government submit rule changes to the AEMC to improve the existing regime of non-firm capacity rights (AMDQ) by:

1. **introducing separate, tradable entry AMDQ rights and exit AMDQ rights**
2. **introducing an exchange to improve secondary trading of AMDQ rights (permanent transfer) and benefits (temporary transfer)**
3. **making AMDQ available for a range of different tenures.**

At the moment the AMDQ regime involves a complex set of arrangements whereby some AMDQ rights are owned by end-users and some are owned by market participants. This makes it complicated to understand who owns AMDQ, who uses the AMDQ benefits, and what can be traded:

- Tariff V customers (residential and small business) collectively own authorised MDQ rights in perpetuity. The *benefits* associated with the authorised MDQ rights (but not the rights themselves) are dynamically allocated to the financially responsible market participant (that is, retailers) in proportion to the number of customers of each retailer.

Agency Injection Hedge Nomination is complex to set up and the limitations are complex to manage.

- Tariff D customers (certain large users) individually own authorised MDQ in perpetuity. The benefits are either:
  - if the tariff D customer is not a market participant, allocated to the financially responsible market participant (that is, the customer's retailer). This is consistent with the treatment of AMDQ held by tariff V customers, who are by definition are not market participants
  - if the tariff D customer is a market participant, held by the tariff D customer
- Market participants (which can include tariff D customers) individually own AMDQ cc and receive the benefits.

In theory, a certain amount of harmonisation is desirable to reduce the complexity of the AMDQ regime and to provide all AMDQ holders, to the extent possible, with the same benefits and trading opportunities. However, it is not intended that tariff D or tariff V customers would lose their in-perpetuity rights to authorised MDQ during this stage of DWGM reforms. Consequently, it is necessary to retain a certain level of unharmonised arrangements.[115]

The remainder of this section sets out different aspects of the Commission's recommendation to improve the AMDQ regime, noting that the detail would be determined through the rule change process.

Separate entry and exit AMDQ

Authorised MDQ and AMDQ cc are point-to-point capacity rights as they are associated with a particular injection point and a particular withdrawal point.

Under this recommendation the rights attached to AMDQ would be separated into entry AMDQ and exit AMDQ, as outlined in Table 4.2. They would no longer be point-to-point rights, but entry rights that refer to a specific physical injection point to the virtual hub (the DTS), and exit rights that refer to a specific physical withdrawal point from the virtual hub (the DTS).

Entry AMDQ and exit AMDQ would not be firm capacity rights. The physical access rights would be no firmer than the existing AMDQ. That is, the DWGM would remain as market carriage and access to the DTS would be determined through the DWGM scheduling process.

115 Note that implementation of the target model under recommendation 4 may reconsider in-perpetuity rights in the second stage of DWGM reforms when firm entry and exit rights are introduced. See final technical report, chapter 4.

Table 4.2 Benefits attaching to entry and exit AMDQ

Benefit	Entry AMDQ	Exit AMDQ
Injection tie-breaking right	✓	×
Withdrawal tie-breaking right	×	✓
Curtailment right[116]	×	✓
Congestion uplift hedge[117]	×	×

Existing AMDQ holders would now hold separate entry AMDQ and exit AMDQ.[118]

Retaining the existing ownership arrangements for authorised MDQ and AMDQ cc drives the following outcomes:

- Tariff V customers: access to the withdrawal point would continue to be dynamically allocated to the financially responsible market participant (retailers) based on customer numbers. This means exit AMDQ and the associated withdrawal tie-breaking rights are not relevant for these uncontrollable withdrawal points.

  However, it is not necessarily efficient that entry AMDQ from Longford is dynamically allocated between retailers in proportion to the number of customers each retailer serves, as they may not have a contract for gas at Longford (the entry point for all authorised MDQ). One option is to continue to dynamically allocate entry AMDQ to retailers, but then allow the retailer to trade this benefit (noting that the quantity of benefits depends on customer number and may change over time). Alternatively, the entry AMDQ associated with tariff V customers could be made available to all market participants (that is, be separated from tariff V customers). That way any market participant, including retailers, could secure the entry AMDQ from Longford. The treatment of entry AMDQ for tariff V customers should be considered further in the rule change process.

- Tariff D customers: would now hold separate entry AMDQ and exit AMDQ:

  — If tariff D customers hold authorised MDQ and the benefits are allocated to their retailer, they would continue to allocate the benefits of entry AMDQ and exit AMDQ to that retailer.

116 In an emergency, tariff D customers without AMDQ are curtailed before tariff D customers with AMDQ. However, the curtailment right does not supercede the existing curtailment rights of uncontrollable withdrawals (tariff V customers). See https://www.aemo.com.au/-/media/Files/PDF/0990-0005-pdf.pdf chapter 4.

117 The congestion uplift hedge would be abolished under recommendation 1.

118 The amount of tie-breaking rights per unit of AMDQ is currently influenced by site diversity factors. This suitability of this should be investigated as part of the rule change process.

- If tariff D customers are a market participant and hold either authorised MDQ or AMDQ cc, they would now hold the equivalent quantity of separate entry AMDQ and exit AMDQ.

- Market customers: would now hold the equivalent quantity of separate entry AMDQ and exit AMDQ.

Going forward, new entry AMDQ and exit AMDQ could be created in the same ways AMDQ can currently be created:

- Through the regulatory process: where an investment in the DTS is part of the regulatory process and leads to greater capacity in the system, new entry and/or exit AMDQ could be created and auctioned to participants. AEMO might also decide that additional entry and/or exit AMDQ could be created as a result of having AMDQ for different tenures, to reflect seasonal demand (discussed below).

- Through market led investment: if a participant underwrites investment in the DTS outside the regulatory led investment process and this leads to additional capacity in the system, the DTS service provider can allocate entry and/or exit AMDQ to that participant.

Improved trading of AMDQ rights and benefits

In 2014 the Commission considered whether to introduce a rule change to facilitate trading of AMDQ benefits. Due to the implementation costs and timeframes, as well at the forthcoming DWGM review, the Commission determined not to make a final rule. The portfolio rights trading rule change is described in Box 4.3.

Box 4.3 Portfolio rights trading

In November 2013, AEMO submitted a rule change request to the AEMC to introduce portfolio rights trading in the DWGM. This would allow holders of authorised MDQ or AMDQ cc to enter into short term trades of some of the market benefits associated with those rights (injection tie-breaking rights and the congestion uplift hedge) for an agreed period of time. This would not affect the ownership of the AMDQ, or any curtailment rights.

The rule change would have required AEMO to develop a new IT interface for registering and confirming bilateral trades between market participants. However, it would not have facilitated the negotiation of contractual terms or the price, the financial transaction itself, or enabled buyers and sellers to find each other.

The Commission made a draft rule determination to introduce portfolio rights trading.[119] It considered that portfolio rights trading would provide an efficient,

119 AEMC, *Portfolio Rights Trading*, Draft Rule Determination, 19 June 2014, Sydney.

flexible and timely mechanism to help participants to better manage their short term risk exposure.[120] However, after this draft decision was published new information was provided by AEMO on the implementation costs and timeframes:

- the cost estimate was revised upwards from $500,400 to $687,500 (a 37 per cent increase)
- the earliest possible date for implementing the IT for portfolio rights trading was revised to April 2016 (from December 2015 and before that April 2015).

Given the reduced net benefit of the rule change and the forthcoming review of the Victorian DWGM, the Commission determined not to make a final rule.[121]

The Commission's recommendation to improve AMDQ trading goes beyond what was envisaged in the portfolio rights trading rule change. It seeks to improve the ability for participants to trade their rights permanently (for the remaining tenure of the AMDQ) or trade the AMDQ benefits temporarily. It also envisages a trading platform that will facilitate all aspects of the trade (finding buyers and sellers, matching and executing trades, and automatically updating AEMO's systems).

Under this recommendation, an electronic trading platform would be introduced where market participants could anonymously post bids and offers to trade AMDQ rights or associated benefits with other market participants.

The trading platform would automatically match bids and offers and execute the trade. This platform could be similar to that recommended by the Commission in the east coast review stage 2 final report with regard to the trading of point-to-point capacity outside the DTS[122] and which is currently being implemented by the gas market reform group. AMDQ trading could occur through standardised products on Trayport, which could incorporate secondary trades into the DWGM systems for settlement.[123]

The Commission has taken into account how each of the different types of AMDQ holders interact with their AMDQ rights, and how they would use entry or exit capacity, in determining their ability to trade. For example:

- Exit capacity is inextricably linked with the end-use customer, whether that is a tariff V customer (such as households) or a large direct connect user that is also a market participant. Exit capacity must remain linked with the relevant customer.
- Entry capacity is not specific to the end-use customer. A market participant can supply its customers (or itself) by injecting gas from any point into the DTS.

120 The AEMC also noted that the benefits of portfolio rights trading would be improved if it were easier to search for suitable trading partners, and encouraged AEMO to further consider some form of listing service with market participants. AEMC, *Portfolio Rights Trading*, Draft Rule Determination, 19 June 2014, pp. 21-22.

121 AEMC, *Portfolio Tights Trading*, Rule Determination, 27 November 2014, Sydney.

122 See recommendation 7 at AEMC, *East coast wholesale gas markets and pipeline frameworks review*, stage two final report, 23 May 2016, Sydney.

123 AEMO, submission to the assessment of alternative market designs, Appendix A, p. 9.

To address these complexities, the different classes of AMDQ holders would have slightly different trading rights. To the extent possible, the Commission is seeking to maximise the number of participants with entry AMDQ and exit AMDQ that can be traded, but without affecting the rights of end users to that AMDQ. Noting that the specifics of entry and exit AMDQ trading would need to be consulted on through the rule change process, the Commission envisages trading could occur in the following ways:

- Tariff V customers: as discussed above, access to the withdrawal point would be dynamically allocated to retailers, therefore exit AMDQ benefits are not relevant for tariff V customers. On the other hand, the entry AMDQ benefits, if dynamically allocated to retailers, should be tradable. This would allow retailers to on-sell the entry AMDQ benefits at Longford if they are unable to use it themselves because they are not injecting gas to service their customers' demand from Longford. In each case the tariff V customers remain the owner of the rights.
- Tariff D customers:
  - If the tariff D customer is not a market participant and the entry and exit AMDQ rights are allocated to a retailer, similar to tariff V customers, that retailer could on-sell the entry AMDQ benefits, but not the exit AMDQ benefits. This is because the retailer would require the withdrawal tie breaking right to deliver gas to the customer, and the curtailment right is untradeable because it remains with the tariff D customer. For example, a retailer for a tariff D customer may not have a contract at Longford, where the entry AMDQ is located. Therefore it could trade this benefit for a short period of time, while it remained the retailer of the tariff D customer. The tariff D customer remains the owner of the rights.
  - If the tariff D customer is a market participant, it would have the ability to trade its entry AMDQ or exit AMDQ permanently,[124] or trade the benefits for a short period of time. Essentially, tariff D customers that are market participants should have the same trading rights and abilities as other market participants.
- Market participants: would have the ability to trade entry AMDQ or exit AMDQ permanently, or trade the benefits for a short period of time.

Table 4.3 provides an overview of the AMDQ rights that could be traded by each type of rights holder.

124 The rule change process would need to determine whether 'in perpetuity' rights sold by a tariff D customer remain 'in perpetuity' AMDQ, or revert to a shorter tenure AMDQ.

Table 4.3 Summary of ability to trade AMDQ

Type of rights holder	Entry AMDQ	Exit AMDQ
Tariff V customer (residential and small business)	Rule change to decide whether entry AMDQ is dynamically allocated to retailers or excised from tariff V customers ✓ If dynamically allocated to retailers, retailers can trade benefits	× N/A - tie-breaking rights are not required at uncontrollable withdrawal points
Tariff D customer that is not a market participant	Allocated to the retailer ✓ Retailer can trade benefits	Allocated to the retailer × Benefits cannot be traded
Tariff D customer that is a market participant	✓ Permanent trade of rights ✓ Temporary trade of benefits	✓ Permanent trade of rights ✓ Temporary trade of benefits
Market participants	✓ Permanent trade of rights ✓ Temporary trade of benefits	✓ Permanent trade of rights ✓ Temporary trade of benefits

While the portfolio rights trading rule change was not implemented because the cost benefit analysis indicated that the change would not be consistent with the NGO, the Commission considers it likely that the marginal costs of this recommendation would be lower than at the time of the rule change decision. This is because the IT requirements for AMDQ trading is expected to leverage off the work currently underway by the Gas Market Reform Group to implement pipeline capacity trading across the wider east coast, which may use AEMO's Trayport system. In addition, the recommendation seeks to improve trading of not just benefits, but of the rights themselves. This is expected to result in more liquid trading and is more likely to meet the NGO than the portfolio rights trading rule change.

AMDQ allocation for different tenures

The allocation of entry AMDQ and exit AMDQ would occur for a range of different tenures, except for the tariff V and tariff D customers who would hold AMDQ in perpetuity.

The rationale for introducing AMDQ of different tenures is threefold:

- It facilitates the seasonal or monthly determination of the amount of entry AMDQ and exit AMDQ, given changing system demand, in order to maximise the amount of AMDQ that is made available to participants.
- It gives participants greater flexibility to decide what tenure of entry AMDQ or exit AMDQ to buy. For example, a participant would not need to commit to 5 years of AMDQ if they only need it for (for example) 3 months.

- It allows new market participants who were not in the market at the time of the five yearly AMDQ auction to more readily obtain AMDQ (this would also be facilitated through the AMDQ exchange described above).

The total amount of entry and exit AMDQ available over the DTS access period would be allocated in tranches. For example, 50 per cent could be allocated for the 5 year period in a single auction (similar to how all AMDQ cc is auctioned now). The remainder could be allocated in smaller tenures throughout the access period, such as yearly and quarterly. The specifics would not necessarily need to be determined in the rule change process, but could instead be determined in consultation with industry during implementation through AEMO procedures.

Determining the amount of entry and exit AMDQ

Currently, the total amount of AMDQ in the market is consistent with the physical capacity of the system, meaning that under normal operating conditions (that is, other than when there is transmission equipment failure or another significant issue on the network) the physical rights provided by AMDQ can be honoured.

The availability of AMDQ is determined by AEMO and agreed to by APA, with the aid of load flow modelling software, taking a probabilistic assessment of whether capacity will be available. The Commission understands that capacity is calculated and released with a probability that it could not be met one day in every twenty years.

At the moment authorised MDQ and AMDQ cc are point-to-point rights that include an injection and withdrawal location. By separating these into entry and exit rights, in the first instance we can be certain that the physical rights can continue to be honoured. Individual rights holders would not have their rights adversely affected.

If participants trade AMDQ, if they wish to change the location of their AMDQ rights they would need to have that transfer approved by AEMO/ the exchange to make sure the system is capable of supporting the change of location. This would follow a similar process as now, whereby changes to the location of the withdrawal point associated with the AMDQ are subject to a transfer algorithm.

Going forward, given that exit and entry AMDQ would be released in seasonal or monthly tranches, it is likely that additional entry and/or exit AMDQ can be released. For example, a 1 day in 20 year summer event is likely to have different loadflow characteristics than a 1 day in 20 year winter event. Additional summer capacity might therefore be able to be released which would not be consistent with the physical capacity of the system in winter. In this way, the AMDQ made available to market participants more closely aligns with the physical capacity of the system throughout the year.

Other matters to be determined

At the moment, AMDQ trades are linked with a close proximity injection point (such as the Longford close proximity point) and withdrawal at the reference hub. The injection point cannot be transferred, but the nominated withdrawal point can be transferred subject to a transfer algorithm which allows trades that are consistent with the physical capacity of the system.

The rule change process will also need to determine where trades for entry and exit AMDQ occur, and under what circumstances they can be transferred to other points.

For example, trades for withdrawal AMDQ could occur at the reference hub, with transfers or nominations to other locations taking place through a separate step. This would maximise liquidity of trades, however there is a risk for the participant that they then cannot transfer the AMDQ to their preferred location. Another option is to limit the trading to similar locations (close proximity points). This may reduce liquidity, but any participant would be free to buy AMDQ rights at one location and transfer it to another location. They would take on the risk by choosing to trade at a different close proximity point. The transfer algorithm could possibly be integrated into the trading platform, depending on the cost and complexity of doing so.

Box 4.4 Examples for entry and exit AMDQ

Example 1: A tariff D customer who holds entry and exit AMDQ is planning to shut down its factory for a month. It could choose to offer its entry and exit AMDQ on the trading platform and temporarily trade it with another participant.

Example 2: A tariff D customer who holds entry and exit AMDQ decides to enter into a supply contract through the forward trading exchange. As delivery is at the DTS, it does not need the entry AMDQ anymore. Therefore it decides to permanently sell the entry AMDQ.

Example 3: A new entrant market participant has entered into a forward contract through the exchange to sell gas. To give it more confidence that it will be able to access the DTS on the day, it buys temporary entry AMDQ benefits from another participant.

Example 4: A retailer wishes to refill the Iona gas storage facility over summer, in preparation for upcoming winter demand. It purchases a quantity of exit AMDQ for the summer period for exit at Iona. This provides it with exit tie-breaking rights to withdraw gas from the DTS at Iona for the summer period.

4.3.3 Benefits of improving the AMDQ regime

The reforms to the AMDQ regime described above are expected to reduce the complexity of AMDQ and make it easier for participants to secure and trade AMDQ rights, as well as being a step towards providing better signals for capacity usage and may facilitate market-led investment.

Introducing separate entry and exit rights may allow participants to better **signal investment needs** at exit points. If demand for AMDQ is high and participants are unable to secure AMDQ from the primary or secondary market, it may provide a signal that more capacity is required. Participants may value AMDQ high enough to underwrite private investment - although the Commission notes that such behaviour is likely to be limited by the free-rider problem described in section 2.2.3. The ability to obtain AMDQ on the secondary market may also defer inefficient investment if participants are able to obtain AMDQ from the secondary market, instead of signalling for more investment.

The ability to obtain exit AMDQ at specific desired locations will also give participants greater confidence that if they underwrite investment or purchase exit AMDQ, the withdrawal tie-breaking rights will be available at the preferred location. However, again, this benefit may be limited by AMDQ not being firm capacity rights, which may not be sufficient to support market led investment.

Separate entry and exit rights may also encourage trading of gas on the DWGM or through the exchange, rather than through bilateral contracts struck outside of the market. Market participants buying gas on the exchange or through the DWGM do not need entry AMDQ (as they are sourcing the gas on the exchange rather than injecting it themselves) but may desire exit AMDQ; conversely, market participants selling gas on the exchange do not require exit AMDQ but may desire entry AMDQ. The current arrangement may encourage market participants to both inject and withdraw their own gas (because by holding AMDQ they have a right associated with injections and withdrawals) rather than to source their gas from a counterparty.

In addition, entry and exit AMDQ rights are more fungible than point-to-point AMDQ rights, as participants have greater ability to tailor entry and/or exit AMDQ to their specific transportation needs.

Introducing a trading exchange to facilitate the trading of AMDQ rights and benefits is expected to provide for more efficient allocation of AMDQ between market participants. To the extent that trading is liquid, having better access to AMDQ (injection and withdrawal tie-breaking rights) will better enable participants to **manage scheduling (volume) risks** from congestion. The trading exchange will reduce transaction costs and enable market participants to more quickly find counterparties.

A trading exchange for AMDQ may **improve trading between regions**, as participants would have a better ability to obtain AMDQ and have greater certainty of being scheduled in the DWGM, which would support trading decisions. The trading exchange enables market participants to secure AMDQ who were unsuccessful during the five year auction, or were not a market participant at the time of the auction. It also reduces search and transaction costs for trading AMDQ, and reduces the complexity of trading for participants.

All of these aspects (better risk management, reduced complexity and reduced transaction costs) may help to **encourage new entrants** into the DWGM.

Allocating entry and exit AMDQ for a range of tenures, including seasonally, is expected to maximise the amount of AMDQ that is made available to participants. The quantity and location of demand for gas across the DTS is significantly different across the seasons. For example, in winter, demand peaks as a result of residential heating requirements. In summer, flows are quite different, with increased demand to withdraw gas to the Iona storage facility, for example. The amount of AMDQ is currently set with regard to the likely capacity of the system on a peak winter day. By allocating AMDQ in more granular timescales, the amount of rights released will more closely align with the likely available capacity across the year. Releasing more capacity in the non-winter period should allow market participants to **better manage scheduling** risk at these times.

Having access to AMDQ of different tenures provides greater flexibility for new entrants or infrequent DWGM participants, as they will not need to commit to five years of AMDQ. This may **encourage new entrants**, in particular smaller new entrants that do not have the resources to commit to AMDQ for five years.

Like introducing the trading exchange, having AMDQ of different tenures also enables market participants to gain access to AMDQ who were unsuccessful at securing AMDQ during the five year auction, or were not a market participant at the time of the auction.

As noted in chapter 3, many of the proposed improvements to the AMDQ regime are consistent with the design features of the target model. This is expected to help DWGM participants adjust to certain aspects of the target model, and may allow a smoother transition to the target model if implemented.

4.3.4 Stakeholder comments

Stakeholders that provided comments on these reforms were generally supportive.

EnergyAustralia agreed that having separate exit AMDQ would provide greater certainty for participants looking to ship gas beyond the DTS, for example into Iona storage.[125]

AGL also supported the introduction of exit rights, including that they be created to mirror existing AMDQ (that is, exit rights should be created from the reference hub to an exit point). However, AGL considered exit AMDQ should only be created to facilitate private investment. In its view, exit AMDQ would exist at the commencement

125 EnergyAustralia, Submission to the assessment of alternative market designs, pp. 2-3.

of the reform, but would be created if a participant underwrites a network augmentation that creates exit capacity.[126]

Origin agreed that AMDQ should be simplified such that AMDQ was not linked with any ancillary benefits (the congestion uplift hedge). Doing this would help to reduce market complexity and clarify the role and value of AMDQ. It would also address the market issue that participants must inject and withdraw gas to receive the ancillary benefits. Origin noted that removing the link between AMDQ and ancillary benefits means a retailer without AMDQ could enter a derivative contract with a shipper holding AMDQ injection rights, and it would have certainty of the price at which it could withdraw that gas.[127]

With regard to harmonising AMDQ rights, Origin considers the current allocation of authorised MDQ to end users to be inefficient and resulting in underutilisation, particularly where those rights are not tradable. It suggests that these rights should be tradable, or at least able to be re-allocated.[128]

AER noted that a trading platform would help to overcome the material search and transaction costs and lengthy processing times involved in AMDQ transfers. It considers this option would improve the ability for participants to manage risk and allocate underutilised AMDQ more efficiently to those who value it most. AER also noted that this option is consistent with secondary trading of capacity rights being implemented more widely across the east coast.[129] MEU considered this would be relatively easy to implement and would provide significant benefits to participants.[130]

AEMO suggested that the allocation of AMDQ should not be limited to five year terms. Even though this aligns with the five year regulatory process, it is not dynamic enough for participants.[131]

In contrast to the comments noted above, one stakeholder suggested that the AMDQ regime be abolished as it is overly complex, administratively cumbersome, incentivises physical hedging and undermines the value of financial derivatives as a tool for managing risk.[132] The Commission considers its recommendations address these concerns to some extent, by removing the link between AMDQ and the congestion uplift hedge (recommendation 1), and by otherwise reducing complexity and the administrative burden associated with securing and trading AMDQ.

126 AGL, Submission to the assessment of alternative market designs, pp. 12-13.

127 Origin, Submission to the assessment of alternative market designs, p. 6

128 Origin, Submission to the assessment of alternative market designs, p. 6.

129 AER, Submission to the assessment of alternative market designs, p. 10.

130 MEU, Submission to the assessment of alternative market designs, pp. 20-21.

131 AEMO, Submission to the assessment of alternative market designs, Appendix A, p. 9.

132 ERM, Submission to the assessment of alternative market designs, pp. 8-9.

4.4 Other suggestions

A number of other suggestions have been raised in submissions to the assessment of alternative market designs, provided to the Commission in May 2017. Insufficient time was available to assess these suggestions fulsomely. Consequently, while these do not form part of the Commissions short or long term recommendations, the options described below should be investigated further in the ways set out below.

4.4.1 Directional flow point constraint pricing

When a constraint arises which limits the flow of gas from an injection point on the DTS, offers to sell gas made above the market price may not be scheduled as a consequence of the constraint. If the injection point is also a withdrawal point, there may also be bids from another market participant to buy gas at that location for more than the offer price of the constrained off gas.

Under the current arrangements, these co-located bids and offers would not be matched and traded, despite the facts that:

- a trade could be executed at a price which is above the seller's willingness to sell (as indicated by its offer) and below the buyer's willingness to buy (as indicated by its bid). That is, an efficient trade could occur
- the trade is physically possible and consistent with the capacity of the DTS, as the exchange of gas will occur at the injection/withdrawal point and not require access to the constrained DTS.

Under the directional flow point constraint pricing (DFPC) mechanism, efficient trades between two market participants at the same location behind a constraint would be facilitated, with settlement of the trade being made at the local price. Consequently, both settlement and volumes would balance.

AEMO considered that DFPC pricing would enable additional trade at constrained locations, where buyers value gas at a price above the DWGM spot price.[133] AGL also considered that DFPC should be examined and that it would provide more valuable price signals.[134]

This option was considered by the gas wholesale consultative forum in 2014. At the time it was not considered worthwhile to pursue due to the implementation costs (it would require changes to the settlement arrangements and scheduling systems). However, if the DWGM scheduling and settlement arrangements are amended as a consequence of the Commission's recommendations in this review, the marginal costs of implementing DFPC could be significantly reduced and this option may meet the NGO.

133 AEMO, submission to the assessment of alternative market designs, pp. 5-6.

134 AGL, submission to the assessment of alternative market designs, p. 14.

The Commission suggests that AEMO revisit this option in consultation with industry and if its benefits are agreed AEMO should submit a rule change request to the AEMC.

4.4.2 Market information

At the moment a certain amount of DWGM information is published on the Natural Gas Bulletin Board (bulletin board) in CSV format. In its submission to the assessment of alternative market designs, AEMO suggested that the existing information could be made more user friendly for market participants, reducing the time, effort and expertise required to interpret it. For example, information could be included on the bulletin board in graphical displays or other easily accessible form.[135]

In addition, stakeholders have raised specific suggestions that the following additional DWGM information be published:

- *Publication of linepack adjustments:* Currently AEMO manages deviations to a schedule by scheduling more or less gas in the next schedule to make up for any deviations, and indirectly passing the cost/revenue associated with this action to the market participants that deviated. This seeks to adjust the level of linepack in the system back to a level deemed appropriate by AEMO. Some stakeholders have suggested that if they had access to (nearer real time) supply and demand information in the DWGM, for example when residential load is increasing, or information about AEMO's intentions to schedule more or less gas to maintain system balance, they could adjust their bids and offers for the next schedule accordingly. AGL notes that linepack adjustment information would help participants manage the risks associated with surprise uplift, which they consider should be retained.[136] In addition, the publication of linepack information could help to reduce the incidence or cost of surprise uplift, as participants will be able to take actions that would minimise the impact.

- *Pre-dispatch schedules*: Currently participants that have been scheduled to inject or withdraw gas into the DWGM can be descheduled throughout the day at subsequent schedules. For example, this could occur if there is a constraint or where there is a change in bids and offers such that the participant is no longer in merit order. Some stakeholders have suggested that publishing a provisional schedule outcome (a pre-dispatch schedule) and more timely market data on pipeline or facility limitations before the schedule cut-off would better enable participants to forward plan and manage volume risk. AGL notes that this is done in the NEM.[137]

The Commission suggests that AEMO considers, in consultation with industry, how existing market information could be more usefully presented to DWGM participants, and whether any new DWGM information should be published. If the changes can be

135 AEMO, Submission to the assessment of alternative market designs, Appendix A, p. 7.

136 AGL, Submission to the assessment of alternative market designs, pp. 7, 15; also supported by MEU, Submission to the assessment of alternative market designs, p. 27.

137 AGL, Submission to the assessment of alternative market designs, pp. 7, 16.

implemented through AEMO procedure changes, this should be undertaken if considered appropriate by AEMO in consultation with industry. If a rule change is required to implement this option, AEMO should develop a rule change request to give effect to the information provision.

4.4.3 Improvements to the regulatory arrangements for investment

As discussed in section 2.3.3, due to the market carriage arrangements in the DTS there is little incentive for participants to privately invest in pipeline capacity. Investment in the DTS is typically through the regulatory process. Given many of the incumbent DWGM participants consider the market carriage arrangements should remain in the DTS, AEMO and the AER made suggestions for improvements to the existing regulatory framework that may assist with providing more efficient investment in the DTS.

AEMO suggested the introduction of a **DTS statutory planning standard** that would be determined by the AEMC in consultation with industry and government, and managed by the AER.[138] This would allow a common view to be developed on whether the system has sufficient capacity and whether additional investment is required to meet a specified level of forecast demand. AEMO suggested that such a planning standard would probably need to reflect the seasonal nature of demand, because it would also guide AMDQ development and the amount of available capacity is related to demand.

In addition, the AER supports a broader **review into the current incentives for APA to invest in the DTS** to determine the nature and extent of any investment issues. Such a review could consider the institutional arrangements governing investment in the DTS, including the incentives under the service envelope agreement between AEMO and APA and the regulatory provisions under the NGR.[139]

The Commission notes that the AEMC is currently considering the economic regulation of covered pipelines, which includes the economic regulation of and incentives for investment in the DTS. Stakeholders are strongly encouraged to raise any issues with or improvements to the DTS regulatory arrangements as part of that review.[140]

4.5 Process for implementing short term recommendations

For each of the short term recommendations outlined above, the Commission recommends that the Victorian Government submit a rule change request to the

138 AEMO, Submission to the assessment of alternative market designs, Appendix A, p. 7.

139 AER, Submission to the assessment of alternative market designs, p. 11.

140 Submissions to the consultation paper close on 22 August 2017. See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-into-the-scope-of-economic-regulation-appli.

AEMC.[141,142] Acknowledging that the detailed design of each of the recommendations has not been finalised through this review, this will enable the AEMC to consider the most effective way to implement the recommendations, in consultation with stakeholders and to best meet the National Gas Objective, consistent with the Commission statutory decision making process.

Each of the stages of the implementation of the short term recommendations are outlined below.

4.5.1 Victorian Government to submit rule change requests

The Commission recommends that Victorian Government develop and submit rule change requests for the short-term recommendations.

It is, of course, not necessary for the rule change request to have determined all the detail and assessed all relevant matters in relation to the issues raised. This will be undertaken by the AEMC, in consultation with stakeholders, through the rule change process.

At this stage the AEMC will also consider whether the pending rule change request from AEMO on the application of constraints in the declared transmission system[143] should be commenced immediately or consolidated with the rule change request related to recommendation 1. While they are seeking to address different issues, they both relate to the DWGM pricing schedule.

4.5.2 AEMC's rule change process

Once the rule changes have been developed and submitted to the AEMC, the AEMC will follow its statutory consultative rule change process.

The Commission will consider whether to formally consolidate the rule change requests, run them concurrently (but separately), or run them on different timelines in order that the quickest changes to implement are completed as soon as possible.

Table 4.4 sets out the NGR changes that would be required to give effect to the short term recommendations, noting that further or consequential NGR changes may be identified during a rule change process.

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141 Rule change requests related to the DWGM must be submitted by either the Victorian Government or AEMO. The NGL is currently being amended to allow any party (other than the AEMC) to submit a rule change request related to the DWGM. However, it has not been finalised at the publication date of this final report

142 The short term recommendations do not require NGL changes and can be implemented through NGR and procedure changes.

143 AEMO, rule change request, Application of constraints in the declared transmission system, 24 November 2016.

Table 4.4 NGR changes for stage 1 reforms

Recommendation	NGR changes required
1: Cleaner wholesale market price	Amendments may be required to Part 19 of the NGR: 1. gas scheduling (r. 215-218) 2. determination of the market price (r. 223 to 224) 3. settlements (r. 234-236) 4. ancillary and uplift payments (r. 239-240)
2: Forward trading at the DTS	Part 19 of the NGR would need to be amended to give AEMO the ability to develop the forward trading exchange, and enable AEMO to develop an exchange agreement for the forward exchange over the DTS.[144] Part 19 may also need to be amended to integrate the net forward positions of exchange participants into the DWGM.
3: Improvements to the AMDQ regime	Part 19 would need to be amended to (among other things): 1. introduce exit AMDQ in the context of withdrawal tie-breaking rights and curtailment rights, and remove references to the congestion uplift hedge 2. enable AEMO to provide a trading exchange for AMDQ, enable market participants to trade AMDQ rights or benefits, and require AEMO to develop procedures for AMDQ trading 3. allow AEMO to allocate AMDQ for different lengths of time

4.5.3 AEMO's system and procedure changes

As a consequence of the NGR changes, AEMO would likely be required to update its procedures[145] and systems[146] to give full effect to the reforms.

Depending on the AEMO procedures and systems that need to be amended to implement the reforms, it may be prudent to implement certain recommendations or parts of recommendations as a package, to minimise implementation costs for participants and consumers. Timing and sequencing would be considered further during the rule change process. AEMO may also be able to start developing system

144 While the forward trading exchange at the DTS can be essentially the same design as the gas supply hub in part 22 of the NGR, it must be established under part 19. This is because the Victorian market has a specific governance framework under the NGL, and to integrate with the DWGM it must be part of the "declared systems provisions", that is part 19 of the NGR.

145 For example, the: uplift payment procedures; ancillary payment procedures; procedures for the transfer of AMDQ; gas scheduling procedure; ancillary functional design; uplift functional design; injection tie breaking functional design; and possibly a review of the market pricing parameters.

146 For example, the: gas supply hub systems; interface between the gas supply hub and DWGM systems; interface between the gas supply hub and AMDQ register; AMDQ register; settlement systems; transportation and market manager system; and the market clearing engine.

and procedure changes prior to the final rule change determination, for example after the draft rule determination.

Where a rule requires system, procedure or other changes from other market institutions to implement, the commencement date for the rule will often be set at some point in the future after the rule is made. This allows for the required changes to be made before the rule commences. If this approach were undertaken with these rule changes, the AEMC would determine the appropriate commencement date through the consultative rule change process, taking into account the benefits of early implementation versus its costs and risks. The AEMC would also take into account any changes required by market participants.

The Commission recognises that system changes are not a trivial task, and require careful planning and management, detailed design work, and thorough testing.

4.5.4 Timing

In the east coast review, the Commission recommended a staged approach to implementing the reforms to the natural gas services bulletin board, pipeline capacity trading and wholesale markets. Implementation of the complete package of east coast reforms could occur over several phases, forming a roadmap to guide the development of the market over the next decade.

The COAG Energy Council has already commenced work on the first phase of work for several of the workstreams from the east coast review. It has commenced a rule change request on the bulletin board and is progressing NGL changes to commence a second round of rule changes on the bulletin board. In addition, it established a gas market reform group to drive the work program on pipeline capacity arrangements.

The Commission's view is that the short term recommendations related to the southern hub should be implemented in the first stage of east coast reforms, by 2020.

The Commission considers the short term recommendations could be implemented in accordance with the indicative timeframes outlined in Table 4.5 below. We note that the below timelines provide for very little contingency and are reliant on the inputs of multiple parties, including the Victorian government and AEMO. The timelines also assume that AEMO procedure changes are commenced once a draft rule decision is made, which may create risks should the final rule determination differ from the draft. Furthermore, the Commission's rule change process is always subject to the potential of an extension if there are sufficiently complex issues raised in submissions or if the rule change request is more complex than had originally been anticipated. Similarly, procedure and system changes may prove to be more time consuming than indicatively provided for below.

Table 4.5 Indicative implementation timeframes

Recommendation	Development and submission of rule change request	Rule change	Procedure/system change
1. Cleaner wholesale market price	4 months	Finalised in further 9 months, with draft determination after 7 months	Finalised in a further 18 months from draft determination
2: Forward trading at the DTS	2 months	Finalised in further 6 months, with draft determination after 4 months	Finalised in a further 12 months from draft determination
3: Improving the AMDQ regime	2 months	Finalised in further 9 months, with draft determination after 7 months	Finalised in a further 18 months from draft determination

The Commission's rationale for the above indicative timelines includes the following:

- Recommendation 1 requires more substantial consideration about the most appropriate method by which it will be achieved. Depending on the precise design, it may require substantial and complex system changes.
- Recommendation 2 is likely to be able to leverage off (but not be identical to) the rules, systems and procedures developed for the gas supply hubs. Consequently, this is likely to allow for a relatively quick implementation.
- Recommendation 3 includes sub-components, some of which may be able to be implemented more quickly than others. In developing the rule change request, the Victorian government should consider whether any aspects of this recommendation should be separated into its own rule change request in order to enable a more immediate implementation. For example:
  - Separating entry and exit AMDQ is likely to involve more changes to the rules than other aspects of this recommendation. Therefore it is likely to take longer to consider all the issues compared to other aspects of this recommendation.
  - A trading platform could be implemented relatively quickly given: a capacity trading platform is currently being developed by GMRG, which may be run by AEMO; and a trading platform (albeit with significantly reduced functionality) was considered in the portfolio rights rule change.
  - The benefits of introducing shorter tenures of AMDQ cannot be fully realised until the next allocation of AMDQ in five years, as an AMDQ cc auction has just occurred. However, shorter tenures of AMDQ could be created immediately to reflect seasonal system capacity, or if additional capacity in the system is created through investment.

5 Longer term recommendation to reform the DWGM

As discussed in chapter 3, the Commission is making a longer term recommendation for reform to the DWGM. This chapter:

- provides an overview of the target model and explains, compared to the short term recommendations, how it better meets the objectives of the review and the COAG Energy Council's vision (section 5.1)
- outlines the Commission's recommendation to review the southern market in 2020 to determine whether to proceed with the target model (section 5.2).

5.1 The target model delivers the COAG Energy Council's vision

The Commission considers the target model is likely to best achieve the objectives of the review and is a nationally consistent approach to achieving the COAG Energy Council's vision.

While the short term recommendations go a long way to meeting the objectives of this review, as set out in section 5.1.2 below, the Commission considers the target model is expected to better meet the objectives of this review. Unlike the short-term recommendations, the target model materially addresses *both* risk management issues and potential issues of efficient investment in the DTS. It is also represents a greater degree of harmonisation between the Victorian market and the wider east coast market.

The target model is expected to provide significant benefits over the long term. The AEMC engaged PricewaterhouseCoopers Australia (PwC) to undertake a high level estimate of the potential economic benefits and costs of implementing the target model.[147] The methodology applied by PwC to estimate the benefits and costs of introducing the target model is consistent with its May 2016 analysis of the benefits and costs of the AEMC's overall east coast gas market reforms, as recommended in the AEMC's East Coast Gas Review.[148]

PwC's analysis estimates that by 2040, the impact on GDP of the AEMC's draft recommendation to implement the target model would be between 0.01 per cent and 0.05 per cent higher than the base case (which assumed the other reforms recommended in the east coast gas review were implemented). This equates to an annual increase in GDP of between $0.2 billion to $1.7 billion by 2040, even once implementation costs have been considered.[149]

147 PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, October 2016.

148 PwC, *Cost benefit analysis of gas market reforms*, May 2016.

149 Consistent with the AEMC's draft recommendation, PwC assumed that the target model would be implemented by 2020.

However, designing, testing and implementing the target model is likely to take a few years, and is not without cost and risk. Therefore the Commission is recommending a staged approach to DWGM reform, with further consideration of the target model in the future.

This section provides a brief overview of the target model, with a detailed explanation available in the accompanying final technical report.[150] It then describes the benefits of the target model against the assessment criteria and stakeholder views.

5.1.1 Overview of the target model

The target model unbundles the three functions currently performed by the DWGM spot market: gas trading; balancing the system; and capacity allocation.

Gas trading

Participants would be able to trade gas on a voluntary, continuous basis. Participants could trade through an exchange, with similar trading arrangements as at the northern hub.

This builds on the trading arrangements established under the short term recommendations, which provide a forward voluntary trading exchange for participants leading up to the gas day. However, under the target model the DWGM would <u>not</u> operate on the gas day. Instead, market participants would trade on the exchange to meet their gas requirements, and then nominate their required gas flows into and out of the DTS (consistent with their capacity rights, discussed below).

The southern hub would remain a virtual hub – any bids and offers could be matched regardless of the actual injection and withdrawal points for the gas. The footprint of the virtual hub would be the same as currently, that is, the DTS.

Balancing the market

At the moment (and under the short term recommendations), AEMO balances the market through the DWGM scheduling process. It schedules more or less gas to accommodate for any participant deviations, to return the linepack of the system to a pre-determined end-of-day linepack target.

Under the target model each participant would be responsible for balancing its own supply and demand position. A participant would be able to adjust its position by buying or selling gas on the exchange, or by altering its injections or withdrawals (consistent with its entry and exit rights).

However, AEMO would remain ultimately responsible for maintaining system security. For example, AEMO would take residual balancing action where market participants are not collectively sufficiently in balance, with the costs of such action

150 AEMC, Review of the Victorian DWGM, *Final technical report*, 30 June 2017, Sydney.

being passed on to the participants that caused the system security issues (that is, the participants that were out of balance).

Pipeline capacity

Under the target model there would be explicit and tradeable firm and non-firm capacity rights for entry to and exit from the DTS.

Firm and non-firm entry and exit rights obtained and held by market participants would be used to manage the flow of gas on the system consistent with its physical capacity, under a system known as "entry-exit". Under the target model, market participants would be able to nominate injections and withdrawals consistent with their entry and exit rights.

This contrasts with the short-term recommendations. While the short term recommendations would introduce the concept of entry and exit capacity rights, AMDQ would continue to be non-firm capacity rights and access to the DTS would continue to be allocated under a market carriage approach.

Box 5.1 The target model in action

As a virtual hub, market participants would not themselves be responsible for flowing gas across the system (as is the case in the current DWGM). To avoid being exposed to the costs of residual balancing actions, a market participant would need to remain in balance such that its cumulative injections (and purchases, including those made in the forward market) equal its cumulative withdrawals (and sales, including those made in the forward market).[151] It could:

- hold sufficient entry rights and nominate to inject gas at point A and hold sufficient exit rights to withdraw the same amount of gas at point B, without trading gas. AEMO would be responsible for delivery of gas (but not necessary the same molecules of gas)
- not inject any gas, purchase gas injected by another market participant on the exchange, and then withdraw the gas consistent with its exit rights
- inject gas consistent with its entry rights and then sell the gas on the exchange to another market participant who would then withdraw the gas
- or a combination of the above.

5.1.2 Benefits of the target model

The target model builds on the benefits provided by the short term recommendations, to better achieve the COAG Energy Council's vision and the objectives of the DWGM

151 A market participant would also not be exposed to the costs of residual balancing actions if it was out of balance in the opposite direction to the system as a whole.

review. It also addresses the areas where the short term recommendations are unlikely to achieve the COAG Energy Council's vision or the objectives of the DWGM review.

This section sets out the benefits of the target model that are additional to the short term recommendations, against the assessment criteria. A full description of the benefits of the target model is set out in the accompanying final technical report.[152]

Risk management

Under the short term recommendations, participants would have greater ability to manage risk by entering into forward physical trades ahead of the gas day. However, they would still need to bid and offer gas into the daily DWGM process to be scheduled, meaning there is still some price and volume risk that must be managed.

The target model removes the daily DWGM and separates capacity allocation from the scheduling process. Participants would voluntarily enter into forward trades for a gas day, secure capacity, and provide their nominations in order to flow gas in the DTS. This gives participants greater ability to manage price and volume risk, as they would have (near) certainty about their ability to access the DTS and the price at which they are buying or selling gas.[153]

Removing the DWGM process means there would be only one mechanism for trading gas (instead of there being a forward exchange and a separate on the day DWGM process). This is expected to further reduce transaction costs and administrative burden for participants. It may also encourage greater liquidity in the market, as market participants would be required to participate in the continuous balancing regime on the day which utilises the same trading mechanism as the forward exchange.

In addition, while the short term recommendations would help to provide a transparent reference price, the target model is likely to provide a more meaningful reference price. This is because it would reflect both short term and long term supply and demand conditions, with all bids and offers being made through a single exchange (instead of an exchange and the DWGM). Better longer term reference prices (that is, greater than day ahead/on the day) can provide signals to promote efficient use of gas and efficient levels of investment, throughout the supply chain.

Investment in and use of pipeline capacity

Under the target model, market participants would have significantly improved incentives to underwrite capacity expansions in the DTS because, in return, they would be able to secure firm access rights to the capacity created.

This contrasts with the existing arrangements, and under the short term recommendations, where capacity rights (AMDQ) are non-firm. Consequently, a

152 AEMC, Review of the Victorian DWGM, *Final technical report*, 30 June 2017, chapter 8.

153 Certainty of access with firm access would not be guaranteed, for example in the event of DTS equipment failure.

free-rider problem exists meaning that typically, investment occurs through a regulatory process.

Under the target model there would be greater incentives for participants to commit to underwrite investment, which has the following benefits:

- market participants are likely to have incentives and information to provide signals to the regulator as to whether an investment is efficient
- if an investment decision is not efficient despite market participants' signals, the cost of that investment is borne by market participants and not by consumers (to the extent that the market in which they operate is competitive such that they are unable to pass through the cost of inefficient investments to consumers)
- investment decisions may be able to be made in a more timely manner than through the existing five-year access arrangement cycle.

Improved trading between jurisdictions

The introduction of a forward trading exchange under the short term recommendations is expected to improve trading between jurisdictions. This is expected to lower transaction costs and complexity for traders operating across multiple markets, encouraging greater participation in the east coast market. However, participants would still need to participate in the daily DWGM to be scheduled.

The target model is expected to further unify trading arrangements between jurisdictions, as it introduces capacity arrangements that are similar (but not the same) as those operating across the wider east coast and extends the forward trading arrangements to operate on the gas day. Removing the DWGM also enables participants to better manage price and volume risk (discussed above) which is conducive for improved trading between jurisdictions.

Upstream and downstream competition

Further unification of trading arrangements across the east coast, a better ability to manage price risk and firmer access to DTS capacity is also expected to be conducive to new entry into the market, particularly by those prospective participants familiar with trading on the other east coast markets.

5.1.3 Stakeholder submissions

While stakeholders generally agreed on the identified issues with the DWGM and the objectives set out in the COAG Energy Council's vision, there was a clear divide in opinion between existing DWGM market participants and potential new participants that may be seeking entry to the market.

Some stakeholders considered the AEMC's target model would allow for the integration of the Victorian gas market with the east coast gas market.[154] As a potential new entrant, Shell stated that the current complexity of market arrangements and the price and volume risk in the market are possible barriers to entry.[155]

The entry-exit proposal for firm capacity rights for pipeline access is supported by RWE, Shell, APLNG and Central Petroleum.[156] RWE, Shell and APLNG have international experience with trading in similar markets in Europe and believe the model has been there operating successfully.

Additionally, PIAC noted that greater transparency would provide many benefits to market participants, such as more confidence in the market, allow for comparability between gas offers and pricing, and would lead to a single price point.[157]

Overall, the AER supported the broad direction of the proposed reforms, but noted some areas of concern to be considered further or clarified.[158] AEMO suggested further investigation of the target model's capability to manage system security in Victoria.[159]

On the other hand, many of the incumbent DWGM participants were cautious about the significant market reform presented by the target model. They preferred that more incremental changes to the DWGM be considered that address the specific issues identified.

The key concerns raised by stakeholders in their submissions are with regard to:

- liquidity in the target model commodity market
- the extent of the current investment problem in the DTS which the target model seek to address
- liquidity in the target model capacity market
- the costs and complexity of the target model.

These concerns typically focus on those aspects of the target model not implemented through the short term recommendations.

154 DWGM draft final report submissions: PACIA, p. 1; APLNG, p. 1; Shell, p. 1; Central Petroleum, p. 1.

155 Shell, DWGM draft final report submission, p. 1.

156 DWGM draft final report submissions: RWE, p. 1; Shell, p. 1; APLNG, pp. 1,4; Central Petroleum, p. 2.

157 PIAC, DWGM draft final report submission, p. 3.

158 AER, DWGM draft final report submission, p. 1.

159 AEMO, DWGM draft final report submission, p. 2.

These concerns are set out below, together with the Commission's considerations. A full account of stakeholder comments on the target model is in the accompanying final technical report.[160]

Liquidity in the commodity market

An advantage of the target model is that it would provide market participants with greater flexibility in the way they manage their gas requirements. Participants would be able to minimise their exposure to imbalance charges by any combination of voluntarily trading gas (which could be done on a continuous basis) and adjusting their physical injections or withdrawals.

However, some stakeholders raised concerns that the voluntary nature of the proposed exchange-based commodity trading on the day would reduce spot market liquidity and potentially increase price volatility. They were concerned that participants would choose to not to use the exchange and instead satisfy their gas needs through their own portfolio of gas held outside of the DTS, and that this would lead to low liquidity and hence higher prices on the exchange.[161]

A number of parties considered that replacing the current DWGM gross pool with voluntary trading would also reduce the transparency and visibility of trades.[162] This is because participants could choose not to use the exchange, and instead trade bilaterally.

The proposed continuous balancing mechanism also raised liquidity concerns amongst stakeholders, mostly because it would also be carried out through the voluntary exchange. ERM and Origin considered that the recommended continuous balancing model could be particularly difficult for small players and new entrants, who are less likely to have access to flexible gas supplies to manage their own balancing position.[163]

Some stakeholders mentioned their concerns around the physical limitations of the DTS, most notably its low levels of linepack compared to in European markets. They suggested that the proposed continuous balancing mechanism would likely result in increased intervention by the system operator, which could be an issue, particularly to small participants that might not have the flexibility to manage their own imbalances.[164]

In the Commission's view, these concerns do not represent enduring problems with its recommended reforms. The Commission considers that, in time, as stakeholders become familiar with the trading platform and balancing arrangements, market participants will have both the ability and incentive to balance their positions through

160 AEMC, Review of the Victorian DWGM, *Final technical report*, 30 June 2017, chapter 8.

161 DWGM draft final report submissions: EnergyAustralia, p. 2; ERM, pp. 1, 4; AGL, p. 2; Origin, p. 4; ENGIE, p. 5.

162 DWGM draft final report submissions: EnergyAustralia, p. 6; ENGIE, p. 5; ERM, p. 1; AGL, p. 2; Origin, p. 4; Seed Advisory, p. 43.

163 DWGM draft final report submissions: ERM, p. 6; Origin, p. 7.

164 DWGM draft final report submission: Origin, p. 8; APA, pp. 14-15, AGL, p. 3; AEMO, pp. 2-3.

the trading platform. To the extent prices are high, market participants with long positions will be able to offer their gas to the market in order to profit from these high prices. This should improve liquidity in the market and, through the process of competition, drive prices downwards.

The forward trading exchange under the short term recommendation will provide participants with some experience in trading ahead of the gas day, to begin building confidence in liquidity.

In addition, a range of transitional measures could be used on implementation of the target model to stimulate liquidity at the hub and to limit the impact of the changed market design on particularly smaller participants. Over time, once liquidity has been established and market participants have adjusted, the transitional measures would be removed and the full target model would be implemented.

Extent of the investment problem in the DTS

Under the target model, the free-rider problem that currently exists in the DTS would be mitigated by the issuance and trading of physical rights providing firm use of capacity. Market participants would also be able to obtain capacity rights by committing to fund capacity expansions, which would improve their incentives to underwrite investments.

However, some stakeholders did not consider that the current framework for investment in the DTS is a particular area of concern. The AER does not consider there is evidence that the existing regulatory framework is not providing efficient and timely investment in the DTS.[165] MEU agreed that the current regulatory investment process is relatively efficient, and considered that moving from market carriage to contract carriage (firm entry-exit rights) would not provide better incentives for new investment.[166] Origin also considered that significant investment has occurred to date in the DTS under the existing framework, however it also noted that incentives for market-led investment could be strengthened and that the introduction of firm entry/exit rights could address this issue to some degree.[167]

The Commission acknowledges that it is not clear that there have to-date been materially inefficient investment decisions through the regulatory process in practice. Nevertheless, it considers that the introduction of firm capacity rights would improve the investment decision making process for the reasons provided in section 2.2.3.

Liquidity in the capacity market

Some stakeholders have also raised concerns about potential low levels of liquidity in the capacity market under the target model (as opposed to the commodity market as discussed above):

165 AER, DWGM assessment of alternatives submission, pp. 10-11.

166 MEU, DWGM draft final report submission, pp. 14-15.

167 Origin, DWGM draft final report submission, p. 6.

- The requirement to align entry and exit rights purchases with supply purchases / load has the potential to erode flexibility for market participants.[168]
- There is a risk that capacity is hoarded by market participants, although this risk is minimised by the recommended capacity release mechanisms proposed by the AEMC.[169]
- Gas fired generators would be negatively impacted by having to pay for ongoing pipeline capacity, as they are not baseload generators in Victoria.[170]

As explained in greater detail in the final technical report, the Commission is recommending a number of design features in the target model in order to address the concerns of low liquidity in the target model capacity market.[171,172] Collectively, the Commission expects these design features to allow ready access to appropriately priced entry and exit capacity.

Costs and complexity of the target model

The recommended unbundling of the commodity and capacity markets was not supported by some stakeholders who considered that the unbundling could result in increased transaction costs, complexity and risk management concerns.[173]

In addition, some participants stated that the proposed continuous balancing model is complex and likely to result in increased operational costs, as participants would have to continuously monitor the balancing position throughout the day.[174]

Recognising these concerns, the Commission has recommended that the short term recommendations discussed in chapter 4 be implemented, which should allow market participants to become more familiar with the target model's design, reducing the risk, cost and relative complexity of the target model's introduction.

In addition, the transitional measures discussed in chapter 7 of the final technical report could be considered on implementation of the target model.

168 DWGM draft final report submissions: Seed Advisory, p. 43; ERM, pp. 1, 5.

169 MEU, DWGM draft final report submission, p. 25.

170 DWGM draft final report submissions: Energy Australia, pp.5-6; ENGIE, p. 5; AGL, p. 3.

171 AEMC, Review of the Victorian DWGM, *Final technical report*, 30 June 2017, chapter 4.

172 For example, exit capacity for distribution networks would be dynamically allocated to prevent retailers from securing exit capacity they do not need. Other entry and exit capacity would be allocated through auctions to allow parties equal opportunity to bid for capacity. Capacity would be auctioned in tranches, again to allow parties equal opportunity to bid for capacity. Capacity could be traded through a secondary market. Finally, any un-nominated capacity would be offered back to the market through a day-ahead auction (use-it-or-lose-it).

173 DWGM draft final report submissions: ENGIE, p. 5; ERM, p. 5; Seed Advisory, p. 43; Origin, p. 10.

174 DWGM draft final report submissions: ERM, p. 6; Seed Advisory, p. 43; AGL, p. 2.

5.2 Assessing the development of the southern market

In the east coast review the Commission recommended, and the COAG Energy Council agreed, that the AEMC be tasked to provide a biennial report in growth in liquidity in wholesale gas and pipeline capacity trading markets.[175] It was intended that this report would be a useful input to inform:

- whether the geographic scope of the Wallumbilla GSH should be expanded
- the appropriate time to simplify the STTM trading hubs
- whether a longer term use-it-or-lose-it mechanism for pipeline capacity is required.

The first report is due to be provided to the COAG Energy Council by mid-2018. While a terms of reference is yet to be received, the Commission suggested that the first report could primarily cover how trading is developing through the gas supply hubs, as well as updating Energy Ministers on how the market is adjusting to the structural changes underway. At the time, the Commission noted that subsequent liquidity reports could measure the development of gas trading and capacity trading at the southern hub, once these reforms are implemented.

The Commission considers that its second biennial review, in 2020, would be an appropriate time to review the development of liquidity in the southern hub. This will allow the Commission to consider the success of the short-term recommendations and the general development of the southern market, and the broader changes across the east coast. Therefore the Commission makes the following recommendation:

> **Recommendation 4:**
>
> **the COAG Energy Council request the AEMC to assess the southern hub gas market conditions in 2020 as part of the existing biennial liquidity review, and provide recommendations on whether to proceed with implementing the target model.**

5.2.1 Content of the liquidity review

In the final east coast review the Commission set out a number of potential quantitative and qualitative liquidity metrics to be used in the liquidity review (outlined in Box 5.2), that were developed in consultation with stakeholders.[176] In assessing the progress of the southern hub and whether to proceed with implementing the target model, the AEMC would draw from these liquidity metrics as well as any other relevant trends

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175 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 final report, 23 May 2016, pp. 42-43.

176 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 final report, 23 May 2016, Appendix F.

that specifically relate to the Victorian market.[177] Liquidity would be considered in the context of both the forward physical market (the exchange trades as well as any observed bilateral trades) and the financial derivatives market.

The assessment of the southern hub would take a holistic review of the progress of market development and the impacts from the first stage of reforms. In order to gain a more complete picture of the progress of market reforms, the proposed liquidity metrics could be supplemented with structural indicators of competition in the market. These structural indicators may include:

- changes in the Victorian market structure. For example, whether new producers or sellers have entered the market (new entrants)
- measures of market concentration, such as the Herfindahl Hirschmann index (HHI)
- gas flows into or out of the DWGM
- gas prices and volatility, and whether participants consider they are able to effectively hedge price risk
- whether investment has occurred in response to increased demand or congestion (higher prices).

Box 5.2 Overview of liquidity metrics

This box outlines some possible metrics that could be used to monitor liquidity in wholesale gas and pipeline capacity trading markets, as outlined in the final east coast review report. Liquidity is a broad concept and, as such, a wide range of metrics, both quantitative and qualitative, are needed to gain an accurate picture of liquidity in the market. Also, as the market develops the relative importance of indicators may change and more sophisticated measures of market liquidity may be required.

Quantitative metrics:

- Churn rate: is the ratio of all traded volumes to the demand for the underlying physical product, whether that is for gas or pipeline capacity. A high churn rate indicates that a market has many participants, trading many different products in large volumes.
- Bid-offer spreads: are the difference between the price on the bid side of the market and the offer side of the market. As such it includes transaction costs, among other things. In a liquid market with many well-informed participants, the bid-offer spread is narrow. This is because supply and demand are well aligned and transaction costs are minimised.

177 For example, ACER 2015, *European Gas Target Model review and update*, January 2015, chapter 4, sets out criteria and metrics to assess the functioning of wholesale gas markets.

- Number of participants engaged in trading: if there is a large number of market participants engaged in trading then it is less likely the market can be manipulated, and therefore the market price will more accurately represent supply and demand conditions.
- Number of trades per product: provides a measure of the growth in liquidity on a per product basis at the hubs.
- Range of products available: in a liquid market there are a range of products available to satisfy all of the needs of market participants. As liquidity grows it is expected that there will be more products available across bilateral, OTC and exchange trades.

Qualitative metrics:[178]

- Confidence of market participants: whether participants have increasing confidence in the market (for gas or capacity) and be more willing to engage in hub-based trading.
- Perception of future market developments: whether participants expect the market to develop in a positive way.

For a full description of the proposed liquidity metrics and approach to monitoring market liquidity, see Appendix F of the east coast final report.

5.2.2 NGL and other changes to give effect to the target model

The Commission has considered the changes to the NGL, NGR and subordinate instruments that may be required to implement the target model.

It is envisaged that the current regulatory framework could be used to implement the southern hub:

- The gas trading exchange over the DTS established in Part 19 of the NGR under recommendation 2 would apply to market participants using Southern Hub based exchange products and is likely to require minimal changes. Parties could trade using the exchange or outside the exchange.
- Other aspects of Part 19 of the NGR (DWGM Rules) would be completely revised to include the new requirements related to capacity and balancing. This new Part 19 would apply to market participants regardless of whether they are trading using the exchange or bilaterally.[179]

178 These will be important with regard to the decision to proceed with the target model. Once participants are familiar with forward trading at the DTS and the introduction of entry and exit AMDQ, the qualitative metrics may indicate whether they have confidence that these concepts are workable in the target model.

179 All trades would be notified to AEMO as the system operator.

- Parts 8-12 of the NGR (economic regulation of pipelines) would continue to apply to the DTS. Some minor changes may be required to support specific aspects of the target model.[180]

- A version of the Service Envelope Agreement between APA as the DTS owner and AEMO as the DTS operator would continue to apply.[181]

As a consequence of retaining the existing regulatory structure, major changes to the NGL appear unlikely. However, some may be required to the extent that any functions and roles change and to manage the transition from AMDQ to the entry-exit model for capacity.

Any NGL and NGR changes and subordinate instruments required will depend on the detailed design of the reforms, which will only be known once the analysis of the target model has progressed.

In some cases, the detailed arrangements do not necessarily need to be contained in the NGR, but instead in subordinate instruments. This is a common approach taken in both the NGR and National Electricity Rules (NER). In these cases the NGR might contain overarching design features and principles, and instruct another body to be responsible for the detail through the subordinate instrument. Such subordinate instruments are likely to include:

- AEMO procedures
- the Service Envelope Agreement
- the DTS service provider access arrangement.

5.2.3 Timing of reform

Should it be decided to proceed with implementing the target model, it is likely to take a few years as this would involve:

- completing a detailed design of the target model
- potentially undertaking market trials
- amending the NGL if that is required, NGR and procedures
- developing and testing new AEMO systems.

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180 Potential changes are discussed further in chapter 4 of the final technical report.

181 Under the Service Envelope Agreement the pipeline operator provides a single service (the reference service) to AEMO, which is the only user of the pipeline under the NGL definition. Shippers access the reference service through AEMO in accordance with the NGL and NGR, with the only relationship between the pipeline operator and shippers being through the transmission payment deed.

A Terms of Reference - Victorian Declared Wholesale Gas Market Review

Background

The Victorian Government recognises that improvements may be made to the operation and efficiency of the eastern Australian gas market, to better facilitate market transparency and transmission capability, and increasing gas supply to meet rising demand at competitive prices.

The Victorian Declared Wholesale Gas Market (DWGM) is a single integrated market that provides participants with the ability to trade imbalances and purchase wholesale gas. The market was established by the Victorian Government in March 1999 to support full retail contestability and encourage diversity of supply and upstream competition.

The DWGM is operated by the Australian Energy Market Operator (AEMO). Between 1999 and 2007, the gas price was determined on a daily *ex post* basis. From 2007, the market moved to *ex ante* intra-day trading following a review by VENCorp in 2003-04, which found that the existing design did not provide participants with the ability to respond to changing market conditions throughout the day.

The DWGM facilitates trading and balancing arrangements for gas market participants, including retailers, gas-fired generators, large industrial users and producers. Since the inception of the DWGM, the market design has stimulated a competitive retail gas market and safeguarded the security of gas supply for Victorian customers. Currently, there are eight gas retailers competing in the retail market and six gas-fired generators connected to the Victorian Declared Transmission System (DTS). Notwithstanding this, substantial developments are set to impact the market over the next few years.

In response to the establishment of a liquefied natural gas (LNG) export industry, the east coast gas market will experience a structural change to demand and supply. Large volumes of gas from Queensland and South Australia will supply the LNG export plants, with end users in these states likely to source increasing volumes of gas from Victoria, transported north via the DWGM and Interconnect Pipeline or Eastern Gas Pipeline. With exports set to begin from late-2014, the domestic market is already feeling the effects of greater competition for gas. These developments are expected to put upward pressure on gas prices and have resulted in a renewed focus on the efficiency of the gas supply chain.

Given the uncertainty around market outcomes for participants, gas market arrangements need to be flexible enough to support a range of potential scenarios out past 2020. It will be important for end users, such as industrial and commercial customers, as well as retailers, to have the ability to effectively manage risk in the DWGM. To minimise inefficient congestion on the DTS, investment to expand the DTS needs to occur in a timely and efficient manner. Interaction between the DWGM and adjacent gas markets should also be as seamless as possible, as this will reduce transaction costs and unnecessary volatility for market participants, minimising costs for end users of natural gas.

It is critical that a review of the Victorian DWGM be undertaken to examine whether the significant structural changes underway in the eastern gas market require reforms to enhance the liquidity, transparency and flexibility of the current arrangements.

In this context, the Victorian Government has requested that the Australian Energy Market Commission undertake, in consultation with AEMO, a thorough review of pipeline capacity, investment, planning and risk management mechanisms in the Victorian DWGM. The objective of this undertaking is to ensure arrangements for access to the pipeline capacity promote competition, risk management by market participants and provide appropriate investment signals and incentives.

The AEMC will undertake the review in accordance with this Terms of Reference and provide a report with recommendations to the Victorian Government for consideration. The Victorian Government notes that the COAG Energy Council has separately tasked the AEMC with reviewing the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast. The two reviews are related in scope and similar in timing and it is expected that the relevant findings and recommendations to be reflected in both reviews (where appropriate).

Purpose

The review is to consider whether the DWGM provides appropriate signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates the efficient trade of gas to and from adjacent markets. More broadly, the review is to consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long term interest of consumers.

These Terms of Reference are intended to guide the AEMC's review of the Victorian DWGM.

Scope

The AEMC is required to undertake a review of the Victorian DWGM that considers:

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

The Victorian Government is concerned that an inability for market participants to effectively hedge risk in the DWGM is limiting the potential of the market to achieve greater transparency and efficiency of trade in natural gas.

The ASX Victorian Wholesale Gas Futures Product is available but not widely traded as it can only be used to hedge against the *ex ante* market price and not uplift charges. Further, while Authorised Maximum Daily Quantity (AMDQ) and AMDQ credit certificates provide participants with some protection against uplift charges, they cannot be used as a hedge against surprise or common uplift charges.

The AEMC is to investigate the underlying issues that are preventing greater use of derivatives and other risk management tools in the DWGM, outline the features of an efficient financial derivative market for gas and the changes that would need to be made in the DWGM to facilitate this.

2. Signals and incentives for efficient investment in and use of pipeline capacity: whether market signals and incentives are providing for efficient use of, and efficient and timely investment in, pipeline capacity on the DTS.

Investment decisions to augment the DTS are currently largely made in response to a five year regulatory determination process. While the DWGM arrangements provide a form of tradeable pipeline capacity rights, through AMDQ and AMDQ credits, these rights have limitations in terms of providing certainty of access when the pipeline is constrained, and in allowing “free-rider” access when spare capacity is available. Consequently, they have been of limited effect in supporting private pipeline investment in the DTS. Investment guided by regulatory processes may be less efficient and timely than relying on market driven incentives. If firm, tradeable access rights to pipeline capacity were available, in a form that addressed these current limitations, this may enhance private investment, as prices for the access rights would signal the need for future investment.

The AEMC is to investigate whether investment in the DTS is expected to continue to occur in a timely and efficient manner. This investigation should also consider the interaction between regulated and private investment and whether the costs of pipeline investment and usage are allocated to users on an equitable basis. If appropriate, the AEMC is to recommend changes to strengthen the signals and incentives for efficient investment, and enhance access to, and short term trading of, pipeline capacity.

3. Trading between the DWGM and interconnected pipelines: To maximise the efficiency of trade in natural gas and facilitate competition in upstream and downstream markets, producers and shippers should be able to effectively operate across the different gas trading hubs on the east coast without incurring substantial transaction costs.

The AEMC is to examine if, and to what extent, the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines. Elements like transparent, adaptable pricing between the DWGM and interconnected pipelines, combined with ready access to pipeline capacity, may be required to enable shippers to better manage risk and facilitate the efficient trade of gas between interconnected hubs and pipelines.

In considering items 1 and 2 above, the AEMC should examine alternative pricing, risk management and pipeline access mechanisms for the DWGM that would also enhance efficient trading of gas with interconnected pipelines and facilities.

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

Taking into account the analysis and any recommendations from the areas of review above, the AEMC should assess whether the DWGM continues to effectively encourage the introduction of new gas supplies to the market and promote competition among retailers in the sale of gas. The AEMC should also comment on the extent to which the design of the DWGM may be a deterrent to large users of gas from participating in the market where it may otherwise be commercially practical for them to do so, and the extent to which this may have an adverse impact on gas usage, trading and market liquidity.

If the AEMC proposes recommendations for market reform, it should clearly demonstrate to the Victorian Government and Council of Australian Government's (COAG) Energy Council how the recommendations address the issues identified, that they continue to safeguard the security of gas supplies to Victorian customers, are proportionate to the problem being addressed and how they promote the national gas objective.

Considerations

In undertaking the review and forming its recommendations, the AEMC is to consider:

- the physical characteristics, size, maturity and interconnectedness of the Victorian gas market;
- the nature of the commercial arrangements underpinning the supply and transportation of gas;
- developments in other eastern Australian gas markets; and
- relevant international experience.

The AEMC is also to consider and incorporate (where appropriate) the findings and recommendations from its concurrent review of Australia's facilitated gas markets.

More broadly, the AEMC is also to consider.

- the National Gas Objective; and
- the COAG Energy Council's Gas Market Development Plan.

Consultation

The Victorian Government requires that the AEMC undertake a formal stakeholder consultation process, including the release of an issues paper, options paper and a draft report for consultation at minimum. If considered appropriate, the AEMC should also hold public forums and/or workshops.

The AEMC is required to establish a stakeholder reference group that will meet periodically throughout the review and prior to the completion of each of the review milestones, and comprise membership of AEMO, representatives of pipelines, consumers, retailers, producers, large users and any other party the AEMC deems appropriate. This stakeholder reference group will also be used for the AEMC's review of facilitated gas markets on the east coast and additional Victorian-specific representatives may be invited.

The AEMC is to utilise the experience of the Australian Energy Regulator as appropriate.

Timeframes and deliverables

The AEMC is to undertake the review over a maximum period of 18 months, taking into consideration the indicative timeframes set out below. This will allow the AEMC to undertake extensive engagement with stakeholders and propose well developed recommendations to the Victorian Government.

The Victorian Government notes that these timeframes represent an upper bound and the AEMC should use its best endeavours to complete each stage of the review promptly and ahead of schedule. Public consultation should be for a minimum of four weeks for each report and a copy of the draft and final reports must be provided to Victorian Government officials and the COAG Energy Council officials one week before publication.

Milestone	Timing
Public forum (in conjunction with the Review of Facilitated Markets)	February 2015
Issues Paper	April 2015
Options Paper	August 2015
Publish Draft Report, including request for Victorian Government response on any significant initiatives identified by the AEMC	December 2015
Final Report	The final report will be published following receipt of the Victorian Government's response to findings and recommendations in the draft report

Before finalising a detailed implementation plan for its proposals in the final report, the AEMC will seek a formal response from the Victorian Government and the COAG Energy Council to some of its recommendations in the draft report.[182]

182 For example, if the AEMC proposes significant changes to the National Gas Rules, the AEMC will seek a response from the COAG Energy Council at the draft report stage before finalising the review.

B Assessment framework

This appendix outlines the assessment framework that the Commission has used for the DWGM review.[183] In providing advice to the Energy Council and Victorian Government, we will explain how our recommendations meet the assessment framework.

The Victorian Government's terms of reference for the DWGM review (provided at Appendix A) requested the AEMC to:

> “...consider whether the DWGM provides signals and incentives for investment in pipeline capacity, allows market participants to effectively manage price and volume risk, and facilitates the efficient trade of gas to and from adjacent markets. More broadly, the review is to consider whether and to what extent the DWGM continues to effectively promote competition in upstream and downstream markets, in the long term interest of consumers.”

Specifically, the terms of reference requests that the AEMC consider the following four issues:

- **Effective risk management in the DWGM**: whether market participants are able to manage price and volume risk and options to improve the effectiveness of risk management activities.

- **Signals and incentives for efficient investment in and operation and use of pipeline capacity**: whether investment in, operation of and use of the DTS will occur in an efficient and timely manner and options to strengthen the signals and incentives for efficient investment in, operation of and use of the DTS.

- **Trading between the DWGM and interconnected pipelines**: whether the current DWGM arrangements inhibit trading of gas between the DTS and interconnected facilities and pipelines, and options to allow producers and shippers to effectively operate across gas trading hubs on the east coast without incurring substantial transaction costs.

- **Promoting competition in upstream and downstream markets**: whether the DWGM continues to encourage the introduction of new gas supplies to the market and promote competition among retailers for the sale of gas, and the extent to which the design of the DWGM may be a deterrent to large users participating in the market.

In assessing these four issues, the Commission has applied the assessment framework set out below.

183 The same assessment criteria were used in the east coast review.

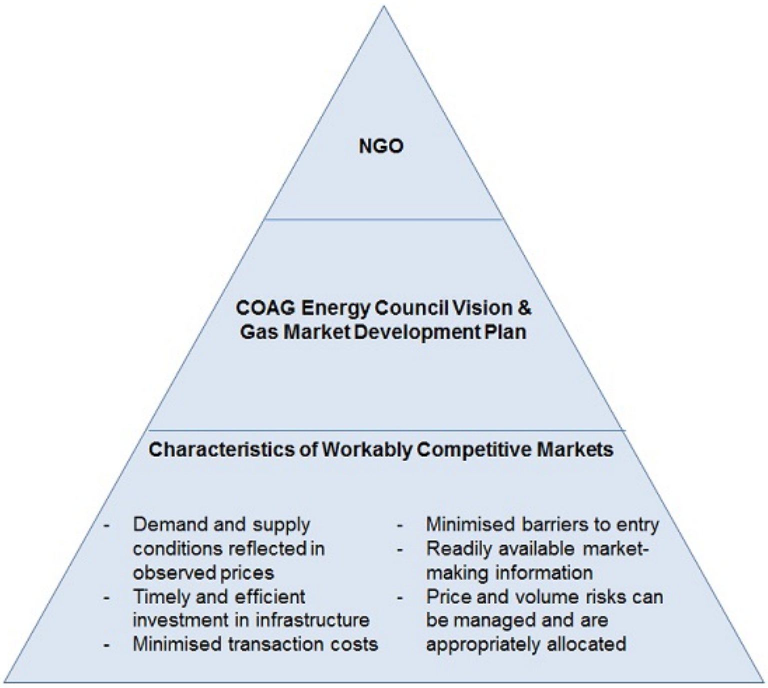
B.1 Assessment framework structure

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

Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets and that are generally required for the NGO and Vision to be achieved. The relationship between the three aspects of the assessment framework is illustrated in Figure B.1, and each is discussed below.

Figure B.1 Assessment framework



B.2 National Gas Objective

In accordance with the 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:[184]

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

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

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

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

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

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

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently;

- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to imitate the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;

- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them; and

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

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

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

B.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference for the East Coast review, which formed the terms of reference for stage 1 of the DWGM review, 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 requested that the AEMC consider the role and objectives of the facilitated gas markets on the east coast, and set out a road map for their continued development in order to meet the Energy Council's Vision for Australia's future gas market, which is as follows:[185]

> "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:[186]

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

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

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

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

3. **Improving risk management:**

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

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

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

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

4. **Removing unnecessary regulatory barriers:**

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

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

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

B.4 Characteristics of a well-functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets.[187] These are:[188]

187 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."

1. Demand and supply conditions reflected in prices: markets participants should have access to a credible reference price reflective of underlying supply and demand conditions that usefully aids commercial decision making.

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

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

4. Price and volume risks can be managed and are appropriately allocated: participants being able to manage operational risks to delivery of physical gas while maintaining safe operating parameters, as well as being able to insure themselves adequately against financial risks.

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

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

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

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

C Industry structure

This appendix sets out the current participants and market participants that are registered in the DWGM, as well as a snapshot of gas production and flows in Victoria in 2016.

C.1 Registered participants

There are currently approximately 24 DWGM market participants, including retailers, traders, and market customers. Table C.1 lists the market participants as at June 2017.[189,190]

Table C.1 Market participants

Type	Companies
Retailers	AGL, Alinta, Click Energy, Covau, Energy Australia, ERM Power, Lumo Energy, M2 Energy (Commander Power / Dodo Power & Gas), Momentum Energy, Origin Energy, Red Energy, Simply Energy, Powershop
Traders	AETV Power, Lochard Energy, Qenos, Santos, Southern Natural Gas Development, Tas Gas, APA
Market customers	Visy Paper, Nova Power, OneSteel Manufacturing, International Power

As this table indicates, the DWGM is characterised by relatively good retail competition. In addition, Sumo Power has a pending application as a retailer registered participant.

Gas powered generators are able to register in the DWGM as a market customer, however these facilities are more typically provided for by a retailer.

A number of other categories of participants are currently registered in the DWGM. Table C.2 lists the participants as at June 2017.[191]

189 AEMC calculation from AEMO, DWGM registered participants list, accessed June 2017.

190 This figure is approximate, noting many companies have duplicate registrations for related entities, or registrations in different categories of registered participant. For example, many retailers are also registered as traders.

191 AEMO, DWGM registered participants lists, accessed June 2017.

Table C.2 Participants

Type	Companies
Interconnected pipelines	Jemena VicHub (Eastern Gas Pipeline), SEA Gas, Bass Gas, Tasmanian Gas Pipeline, Gas Pipelines Victoria (Coastal pipeline)
Distribution pipelines	Australian Gas Networks, Multinet, AusNet Gas Services
DTS service provider	APA
Storage providers	APA, Iona Operations (Lochard Energy)
Producers	BHP Billiton, Esso Australia Resources
Market operator	AEMO

C.2 Gas production and flows in Victoria

In 2016, production from the Gippsland basin was 314 PJ. This is trending upwards and is 24 per cent higher than production in 2015. Production from the Otway basin was 71 PJ in 2016, down 15 per cent from 2015 production. Production from the Bass basin was 17 PJ in 2016, an 11 per cent increase from 2015 production.[192] The AER has noted that gas production in offshore Victoria is declining, especially in the Otway and Bass basins. Based on advice from producers, AEMO has projected gas production in offshore Victoria will fall by 38 per cent between 2017 and 2021. This is making customers heavily reliant on sourcing gas from the Gippsland Basin.[193]

According to the Gas Bulletin Board data, in 2016: the Longford gas plant produced 312 PJ; Lang Lang (BassGas) produced 15 PJ; Minerva gas plant produced 15 PJ; and the Otway gas plant produced 35 PJ.[194]

A majority of the gas produced in Victoria is transported into the DTS. In 2016, 214 PJ of gas was transported from Longford into the DTS, while 97 PJ flowed north along the Eastern Gas pipeline and 13 PJ flowed south along the Tasmanian Gas pipeline. A total of 8 PJ was transported into the DTS from Iona (noting the bidirectional flows shown in Figure C.1 below), while 58 PJ flowed to Adelaide along the SEA gas pipeline. In addition, 21 PJ was transported into the DTS from NSW through Culcairn.[195]

Figure C.1 shows the flows of gas into and out of the DTS pipelines in Victoria. Positive flows indicate flows into Victoria.[196]

192 AER, state of the energy market 2017, p. 69.

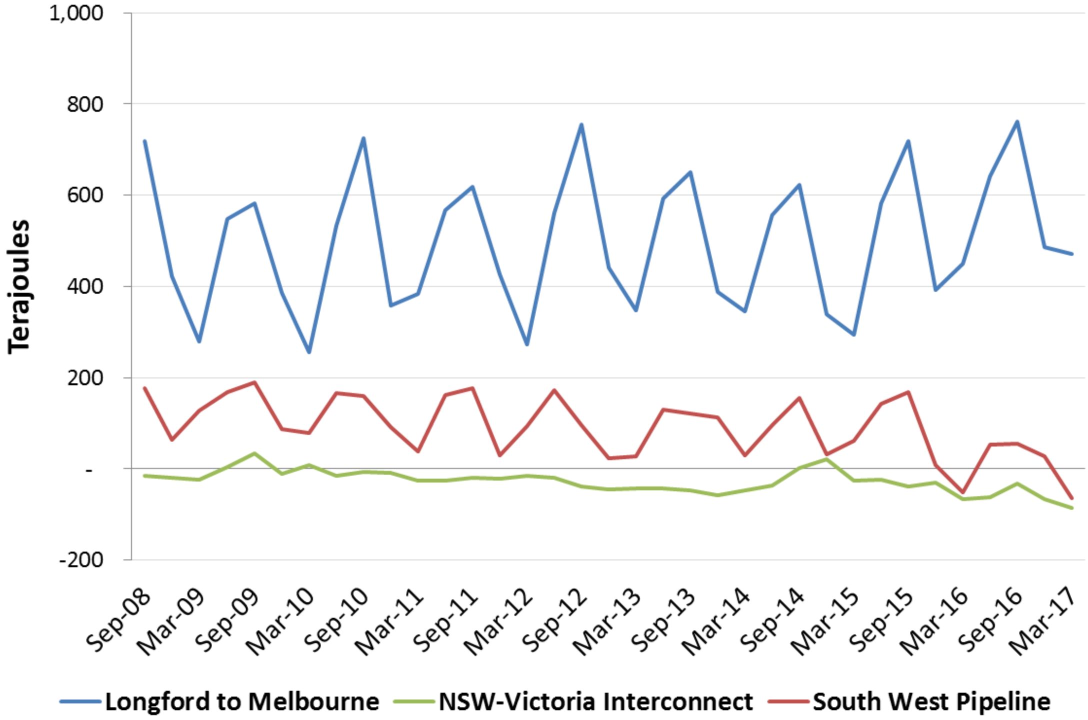
193 ibid. p. 82.

194 AEMO, Bulletin Board data, report for actual gas flows, accessed June 2017.

195 ibid.

196 ibid.

Figure C.1 Monthly Victorian gas demand



This shows that the Longford to Melbourne pipeline always flows into Melbourne, and varies on a seasonal basis. The South West pipeline mostly ships gas into Melbourne, except for the summer months where it sometimes changes direction and ships gas out of the DTS. Over time, this has trended to higher flows out of the DTS in summer months. On the other hand, the NSW-Victoria interconnect typically flows gas from Victoria into NSW, although at lower volumes than the other pipelines discussed.

Abbreviations

ACCC	Australia Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity
AMDQ cc	AMDQ credit certificates
AMIQ	authorised maximum interval quantity
ASX	Australian Securities Exchange
COAG	Council of Australian Governments
Commission	See AEMC
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
GMRG	Gas Market Reform Group
GSA	gas supply agreement
GSH	Gas Supply Hub
LNG	liquified natural gas
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
PJ	petajoule
POS	position
SCO	Senior Committee of Officials

SEA	Service Envelope Agreement
SEA Gas	South East Australia Gas Pipeline
STTM	Short Term Trading Market
TJ	terajoule