REVIEW

Australian Energy Market Commission

DRAFT FINAL TECHNICAL REPORT

Review of the Victorian Declared Wholesale Gas Market

21 October 2016

Submissions due 2 December 2016. Reference: GPR0002

Draft Final Technical Report

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About the AEMC

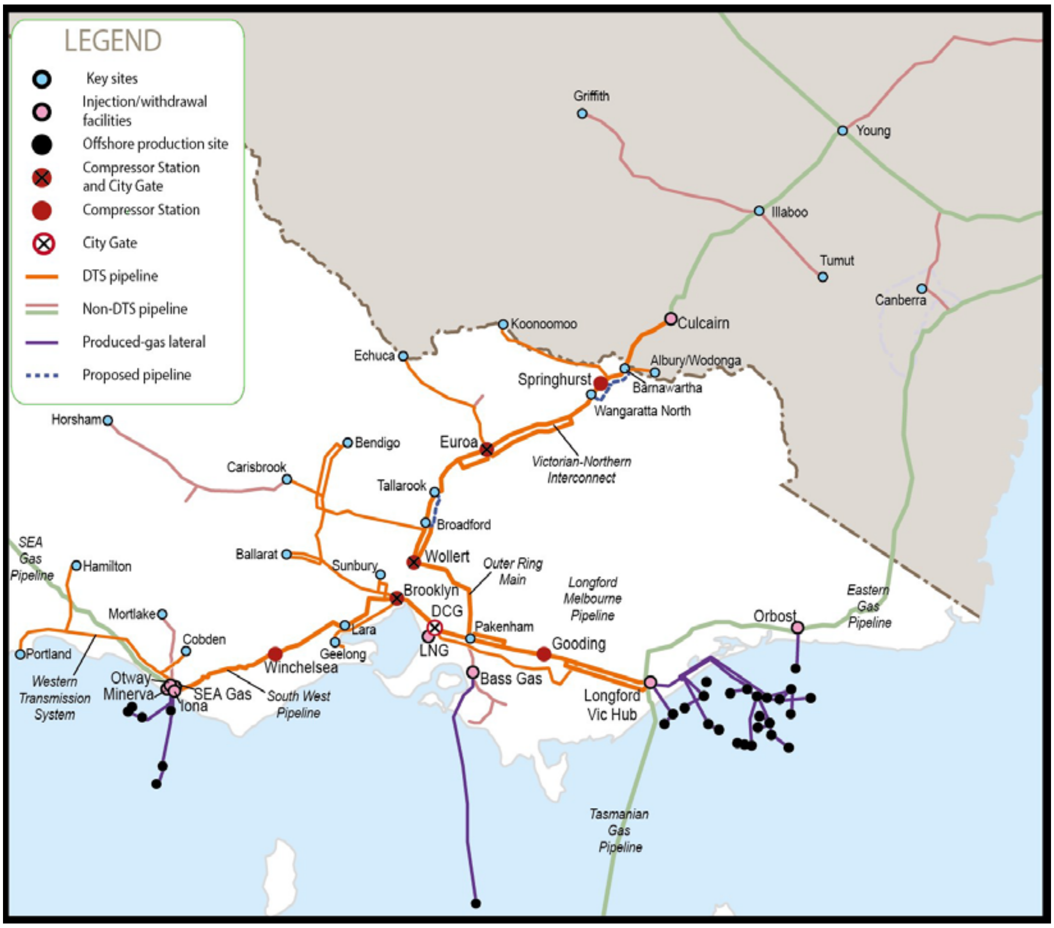
The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Contents

1 Introduction

The Victorian Declared Wholesale Gas Market (DWGM) was established in 1999 by the Victorian Government and is the longest-standing wholesale gas market in Australia. It encompasses the entire declared transmission system (DTS, see Figure 1.1), which comprises of pipelines extending from Longford 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.

Figure 1.1 Victorian Declared Transmission System



In recent years, the wider east coast gas industry has undergone a profound structural change, and market participants in the DWGM are now experiencing the effects of this.

During the more stable market environment of the recent past, DWGM 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, changed market dynamics have prompted a need for greater flexibility in how gas is bought and sold outside of Gas Supply Agreements to better manage risk. The commencement of liquefied natural gas (LNG) exports from Queensland has exposed the eastern Australian gas industry to conditions in international gas markets, putting upward pressure on domestic prices, presenting a new risk in the form of prices in Gas Supply Agreements being linked to oil prices (because international gas prices are linked to oil prices), and resulting in increased spot price volatility. This volatility is likely to remain a permanent feature of the market going forward.

As a result, producers are typically now offering Gas Supply Agreements at higher prices, for shorter durations and with more restrictions on volume flexibility previously used to manage risk. Volume flexibility in Gas Supply Agreements has traditionally been the key means used to manage the risks associated with spot price volatility in the DWGM. Consequently, greater flexibility in how gas is bought and sold outside of Gas Supply Agreements and new approaches to managing spot price volatility 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.

In light of these changes, 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 detailed review of the Victorian DWGM ("the DWGM Review").[1] Primarily, the review was 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.

The Commission provided a Draft Final Report to the COAG Energy Council on 14 October 2016 that investigates the issues facing the current DWGM and sets out the Commission's recommendations to address these issues.[2] The recommendations principally involve introducing a "Southern Hub" across the DTS, which would involve substantially reforming the DWGM to introduce new arrangements based on an entry-exit model, which is widely used across Europe, and introducing a trading exchange.

The Draft Final Report includes descriptions of the different aspects of the 'target' model and lists the Commission's 'required', 'preferred' and 'suggested' features of each recommendation (explained further below).

This Technical Report provides additional detail on each of the 'required', 'preferred' and 'suggested' features of the Southern Hub model. In particular, it explains the 'preferred' and 'suggested' features, which are not discussed in detail in the Draft Final Report.

1 Victorian Government, *Victorian Declared Wholesale Gas Market Review*, Terms of Reference, 4 March 2015.

2 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Final Report, 14 October 2016.

1.1 Overview of the Southern Hub model

The recommendations related to the design of the target model are to:[3]

- **Recommendation 1:** Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.
  - Gas trading and balancing in the DWGM currently occurs on a mandatory, operator-led basis. This should transition to the new Southern Hub model, where trading would occur on a voluntary, continuous basis. Participants would be able to trade either bilaterally or through a low cost, anonymous trading exchange, based on the current Gas Supply Hub model. Trade would occur at a notional point – bids and offers would be matched regardless of the actual injection and withdrawal points for the gas.
- **Recommendation 2:** 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 ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.
  - Continuous balancing means that market participants would not be required to exactly balance their positions at any particular point in time. However, if AEMO, as system operator, was required to buy or sell gas to maintain system security, the participants responsible for the imbalance would be allocated a portion of those costs.
- **Recommendation 3:** The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.
  - The existing market carriage model for allocating capacity in the DTS, and associated limited pipeline transportation rights, should be replaced with a system of entry and exit rights. These rights would enable participants to be confident that their nominated injections and withdrawals would be achieved. Entry and exit rights would be made available through a variety of channels, including secondary trading.

Implementing the Southern Hub model would transform the way in which market participants access and trade in the Victorian gas market, and the way in which the need for pipeline investment is signalled. Specifically:

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3 There are two further recommendations in the Draft Final Report that relate to transitional measures and implementation. These are not discussed in this Technical Report as the focus of the Technical Report is the target model.

- Market participants would have the opportunity to trade gas with other market participants (and, in some cases, the system operator) on a voluntary and continuous basis. This would allow them to better manage their gas portfolios in response to both their short and long term needs and to better manage price risk. In time, the trading of standardised physical products might provide better pre-conditions for financial derivative products to develop, providing further means to manage risk.

- The prices from trading activity on the exchange and bilateral trades would provide market participants with transparent and meaningful reference prices that would reflect both short term and long term supply and demand conditions. This would provide signals to promote the efficient use of gas and investment throughout the supply chain.

- Market participants would be able to obtain firm access rights to the DTS. Committing to the entry and/or exit rights would allow market participants to provide clear signals for investment in pipeline infrastructure, as the 'free rider' issues of the current DWGM would be avoided.

As part of the Draft Final Report and this Technical Report, the Commission has identified various outcomes that might be pursued for each of the components of the package of reforms. Where the Commission considers that a particular recommendation is necessary for the overall reform to be effective this has been reflected as a **required** outcome, and the Gas Market Reform Group (GMRG) should be tasked by the COAG Energy Council to further develop the package of regulatory changes which delivers it.[4] In other cases, Gas Market Reform Group would be better placed to consider the specific details of the reforms, given the expertise of its members:

- In some of these cases, the Commission has highlighted its **preferred** outcome which the Commission recommends the Gas Market Reform Group should pursue unless it is clear that there are greater benefits in alternative approaches. The Gas Market Reform Group should be required to have a strong rationale to depart from implementing a preferred outcome.

- In other cases the Commission has **suggested** the most appropriate outcome given the in-principle benefits that may arise from its implementation, which the Gas Market Reform Group should consider in its analysis.

1.2 Structure of the Technical Report

This Technical Report sets out the features of the proposed Southern Hub target model and is structured as follows:

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4 In August 2016 the COAG Energy Council agreed to establish a Gas Market Reform Group to implement recommendations made by the Commission it its East Coast Wholesale Gas Market and Pipeline Frameworks Review.

- Chapter 2 relates to commodity trading;
- Chapter 3 relates to balancing;
- Chapter 4 relates to capacity allocation;
- Chapter 5 explains how cashflows arising in balancing and capacity allocation would be settled; and
- Chapter 6 discusses the Commission's initial views regarding the allocation of institutional roles in the Southern Hub model.

1.3 Responding to this Technical Report

The Commission welcomes responses on the proposed changes to the Victorian DWGM outlined in this Technical Report. Any feedback received from stakeholders will be used to inform the Commission's final recommendations for the DWGM Review.

The Commission is also consulting on the associated Draft Final Report and it is not necessary to provide separate submissions on the two reports.

Submissions on the Technical Report (and Draft Final Report) are due no later than Friday 2 December 2016.

Submissions should refer to the AEMC project number "GPR0002" and be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au.

All submissions received will be published on the AEMC's website, subject to any claims for confidentiality.

2 Commodity trading in the Southern Hub

Box 2.1 Recommendations

Recommendation 1: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.

Commodity trading under the Southern Hub model would have the following features:

1. **Capacity would be sold separately to commodity**: market participants would obtain capacity through a separate mechanism to commodity sales. As a result market participants would no longer have to bid all gas into the market to allocate capacity (scheduling) and different models for commodity trading would be possible.

2. **Commodity trading would be voluntary and continuous**: market participants may trade bilaterally (through long-term contracts or OTC contracts) or through a Southern Hub trading exchange that would be the same as the Northern Hub exchange.[5] Trading may occur at any point in time (continuous) and a number of different products would be available through the exchange.

3. **The Southern Hub would remain a virtual hub**: all gas within the hub would be fungible and trading would occur at a 'notional point' (not a physical location). Therefore market participants would be able to trade with each other regardless of their location within the DTS (subject to having suitable capacity rights).

4. **Trading products determined in consultation with market participants**: the trading products could be based on those offered in the existing Gas Supply Hub in the first instance, but tailored to meet the needs of DWGM participants.

2.1 Capacity is separated from commodity sales

In the existing DWGM (which is a 'market carriage' model), capacity and commodity sales are combined into the same process. Market participants place bids and offers for all gas for the upcoming gas day, and are scheduled (granted capacity) on the basis of the outcome of those bids and offers. The transport of gas is implicitly bundled with

5 The East Coast Review recommended that the existing Wallumbilla Gas Supply Hub would be further developed to form the basis of a Northern Hub. This would initially be facilitated by AEMO's optional hub services program to create a single pricing point.

the sale of gas and as such, the trading arrangements must conform with, and are limited by, the scheduling process.[6]

Separating capacity from commodity sales would enable different models for commodity trading. There would no longer be a requirement for all gas to be bid or offered into the DWGM to facilitate scheduling. It would also mean that, administratively, commodity trading is completely separated from capacity sales.

As a consequence, market participants would be able to trade gas beyond the day or a day ahead. Participants could enter into a physical position and better manage their risks by seeking out longer term trading arrangements.

The separation of capacity and commodity sales is the same approach as taken in the existing Gas Supply Hub (GSH) design at Wallumbilla (see Box 2.2), although the nature of the capacity rights are fundamentally different (being point to point rights for the existing Gas Supply Hub, which would become the Northern Hub, versus an entry-exit model in the Southern Hub).

The means by which capacity would be allocated to market participants is the subject of Chapter 4.

2.2 Continuous, voluntary and exchange based trading

2.2.1 Trading under the existing DWGM

The DWGM facilitates the trading of gas between market participants. 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.[7]

Trading is mandatory, meaning that all gas must be offered into and bid out of the market, even if it is the same market participant on both sides of the trade.[8]

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 by minimising the cost of supplying demand.[9]

6 Market participants may acquire quasi-capacity (tie-breaking) rights through AMDQ(cc), which provide a holder with preferential dispatch when gas is offered at the same price as other market participants.

7 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 and scheduled.

8 Approximately 80 per cent of trades involve one market participant bidding into the market at the floor price and out of the market at the price cap, thereby ensuring its trade.

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

If parties wish to bilaterally trade gas, this can only occur on the periphery of the DWGM, such as at Longford. Market participants must still participate in the DWGM each day and be scheduled on that basis. Participants cannot manage their risk by entering into a physical position within the DWGM itself.

2.2.2 Trading under the Southern Hub

The Commission recommends that trading in the Southern Hub should occur on a voluntary, continuous basis. One of the options for commodity trading would be through an exchange that utilises the existing Gas Supply Hub design. The Gas Supply Hub allows market participants to voluntarily buy and sell gas as a complement to existing bilateral agreements through an exchange that continuously matches buyers and sellers. See Box 2.2.

Box 2.2 Key features of the existing Gas Supply Hub

The Gas Supply Hub is a market design that has been implemented at Wallumbilla in Queensland and Moomba in South Australia, to facilitate upstream trading of gas. It provides a low cost and flexible method for market participants to voluntarily buy and sell gas as a complement to existing bilateral agreements.

The Gas Supply Hub is not a virtual hub. There are three trading locations at Wallumbilla and two trading locations at Moomba.[10] Participants are responsible for managing their own transport and must be able to deliver gas to, or receipt gas from, the trading location. This means that participants must have existing Gas Transportation Agreements and arrangements for hub services to move gas across the hub.

Trades are matched anonymously, although there is a separate mechanism that allows participants to agree bilaterally to a standardised product and then register the transaction. This can lower transaction costs, and also reduces counterparty risk. As the exchange essentially matches buyers and sellers, if a participant defaults on their delivery, the counterparty does not receive the gas.[11]

The Southern Hub model would have the following features with regard to trading:

1. **Trading would be voluntary**: market participants would be able trade bilaterally (through long term contracts or OTC contracts) or through an exchange. There would be no need for a market participant to 'trade' with itself.

10 Deliveries are netted each day by AEMO to minimise the number of transactions that need to be delivered. Each trading participant receives a net gas delivery obligation and is responsible for delivering gas to that location using existing contractual supply and transportation agreements.

11 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.

2. **Trading would occur continuously**: market participants would be able to trade at any time using a variety of products of different lengths of time.

3. **Balancing would be market-based**: market participants would be primarily responsible for balancing (by trading among themselves) and the system operator would have a residual balancing role when the system as a whole is out of balance, to maintain the system within safe operating limits (discussed in detail in Chapter 3).

This market design is referred to as 'voluntary trading with market-based balancing' since participants would not be forced to make bids and offers for gas injections and withdrawals within the balancing period. Rather, they would be incentivised to trade and remain in balance. In this sense, it is the market that would be primarily responsible for keeping the DTS in balance.

Under the new arrangements, market participants would have greater flexibility to purchase gas from three key sources:

- the exchange;
- bilaterally, using OTC contracts; or
- long-term gas supply agreements (GSAs).

A key difference between the proposed Southern Hub and the existing Gas Supply Hub is that, in the Southern Hub, a party purchasing gas from the exchange would be guaranteed delivery.[12] If a counterparty to a transaction defaulted on a delivery obligation to the Southern Hub, it would be incentivised to restore its balance, or be cashed out if it cannot. The system operator would maintain balance within the network.[13]

In addition, transitioning the existing DWGM to exchange-based trading (with market-based balancing) is expected to establish meaningful reference prices for the Southern Hub. In particular, the exchange would publish an end of day, volume-weighted price which would provide the market with a single price that financial derivative products could reference.

2.2.3 Other design features for the Southern Hub

A number of other Gas Supply Hub design features may be suitable for the Southern Hub and should be considered further during the implementation phase in consultation with market participants.

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12 While a defaulting party must compensate their counterparty for 25 per cent of the value of the variation, this compensation is the only remedy available for a breach of a participant's delivery obligations. This may under or over compensate a participant for their actual direct costs associated with the delivery default.

13 Balancing mechanisms are discussed in Chapter 3.

The introduction of a Southern Hub exchange based on the existing Gas Supply Hub design could support the implementation of common:

- gas day start times;
- trading platforms (Trayport) and back-end systems;[14]
- registration;
- prudentials;[15]
- settlement; and
- training.

Consistency in these types of design features should lower transaction costs and complexity for market participants operating across multiple markets, encouraging greater participation in the east coast market.

2.3 A virtual hub

While the Commission recommends that the Southern Hub would have similar characteristics to the existing Gas Supply Hub, one of the key differences would be that the Southern Hub, like the existing DWGM, would remain a virtual hub and would continue to encompass the DTS.[16]

A virtual Southern Hub means that participants trading on the exchange would only see one trading location, instead of three trading locations as is the case in Wallumbilla. Participants may trade with each other regardless of their location on the DTS:

- All gas within the hub would be fungible. Market participants can inject gas at one point and withdraw from another without planning the transport of that gas between the points.
- Trading would occur at a 'notional point' and not one or more physical locations.
- Market participants would be responsible for delivering gas to the hub and withdrawing gas from the hub. They do not need to concern themselves with transporting gas between those points.
- The system operator would be responsible for managing gas flows within the hub, to manage system security and ensure the delivery of gas to all market participants.

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14 Significant upgrades would likely be required to Trayport and/or the back end systems to support trading in the Southern Hub. The data and trading in Victoria will be more critical because the exchange will be vital for participants and the system operator to keep the market in balance.

15 Having consistent and pooled prudential requirements across both markets means that participants will not need to put forward duplicate credit requirements.

16 The use of a virtual hub will assist in maximising liquidity by allowing participants located at any point on the DTS to trade with each other. While the creation of additional virtual hubs would have significant impacts on pipeline regulation and capacity allocation, this is not the case with the DTS. The Commission has not been persuaded that changing the scope of the DTS is necessary to realise the benefits of the reform.

While the location of a counterparty's injections or withdrawals within the virtual hub is not relevant for market participants, the system operator would likely need access to more granular information on the location of gas offers on the exchange. This would enable the system operator to purchase gas from a specific location to manage locational constraints and security of the system. Otherwise, there would be no guarantee that the purchase would address the network issues.

Locational information or a locational product for the system operator could be considered during the implementation phase, along with short-term products (discussed in section 2.4 below). If suitable products were available the system operator could use the exchange to select and purchase the cheapest gas that is available at a location that would resolve the system issue.

This locational approach to system security management is carried out in the existing DWGM, where every four or eight hours the market operator uses an algorithm to select the cheapest gas to meet demand, but then constrains off some of the cheaper gas in favour of some more expensive gas that can meet the demand given the physical limitations of the system. Balancing and the management of network constraints are discussed further in Chapter 3.

2.4 Trading products

The existing Gas Supply Hub offers a range of trading products of different lengths to suit the trading needs of market participants and the system operator (in its residual balancing role) (see Box 2.3).

Box 2.3 Existing Gas Supply Hub trading products

The trading products currently available through the Gas Supply Hub are:[17]

- monthly;
- weekly;
- daily;
- day-ahead; and
- balance of day.

These products typically require a uniform flow rate over the delivery period and a minimum parcel size of 1,000 GJ for each gas day in the delivery period (or 25 GJ/hour for the balance of day product).[18]

In addition, three physical spread products are available from Moomba to Wallumbilla.[19] These are monthly, daily, and day-ahead products.

17 Specifications for each of these trading products are located in the Gas Supply Hub Exchange Agreement, available on the AEMO website.

18 The Gas Supply Hub Exchange Agreement was recently amended to reduce the minimum parcel size to 100 GJ per day, except for the balance of day product. This will take effect from 26 October 2016. Product specifications would need to be further reviewed on implementation in the Southern Hub exchange.

The trading products to be offered on the Southern Hub could be based on these, but tailored to meet the specific needs of market participants. Products should be developed having regard to the physical capabilities of the DTS and the wider market design.

In particular, there is likely to be a need for shorter-term products in the Southern Hub market to meet the balancing needs of both participants and the system operator. There are a number of temporal aspects to such products that would need to be considered during the implementation process:

- the duration of the product;
- the lead time between purchasing the product and delivery into the DTS;
- with regard to the system operator (in its residual balancing role), the lead time between delivery into the DTS and the arrival of that gas at any specific points where pressure levels threaten system security.

In addition, where the system operator was one of the parties to a transaction (i.e. it is balancing the system for system security reasons) it would need to be satisfied that the trade would lead to a change in nominations. This is discussed further in section 3.3.3.

As with the development of products for the existing Gas Supply Hub, products for the Southern Hub exchange could be easily added or removed, in consultation with market participants, to suit their trading needs over time. The Commission recommends that suitable products be developed in close consultation with market participants during the implementation process for the Southern Hub.

19 This gives participants the option to swap gas between the trading locations.

Table 2.1 Summary of required, preferred and suggested features of the Commission's recommendations

	Required design feature	Preferred design feature	Suggested design feature
Recommendation: Implement a new Southern Hub model where trading would occur on a voluntary, continuous basis. Trading arrangements would be the same as at the Northern Hub. The Southern Hub would be a virtual hub retaining the existing footprint of the DTS.			
Unbundling from capacity	• Commodity sold at the hub would be unbundled from capacity rights. These would be sold separately.		
Commodity trading	• The existing mandatory daily gross pool scheduling process for trading gas for the upcoming day would be replaced by voluntary, continuous trading. • One of the options for trading would be an exchange similar to the GSH design. • Market participants would be able to trade outside the exchange (bilaterally or OTC) within the DTS, but this would now be at the virtual point.	• The exchange would utilise the existing GSH trading platform (Trayport). • The exchange would utilise existing GSH credit and risk management processes.	
Virtual hub	• The Southern Hub would be a virtual hub, meaning: — all gas inside the hub is fungible; — trading occurs at a 'notional point'; — market participants deliver gas to the hub and receipt gas from the hub; — the system operator is responsible for managing gas flows within the hub.		• More granular trading locations may be required for the purposes of congestion management by the system operator.

	Required design feature	Preferred design feature	Suggested design feature
Commodity products	• Products available through the hub would be determined in close consultation with market participants.	• Products initially provided could be based on those offered at the GSH.	• Products for more immediate delivery may be required by: — system operator for network security management; — market participants for balancing.

3 Balancing

Box 3.1 Recommendations

Recommendation 2: 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 ensuring system security. This would include a residual continuous balancing role that would oblige the system operator to take action where market participants are not collectively sufficiently in balance to maintain system security.

Balancing is an integral part of a physical gas market because injections into the system must over time equal withdrawals, and pressures must remain within operational limits to maintain system security. Balancing at the Southern Hub would be the process by which supply and demand would be adjusted to ensure that the system remains secure, with the following key design features:

Balancing would take place at the virtual hub. This would maximise liquidity as there is no defined physical location for balancing, consistent with the rationale for commodity trading more generally, as discussed in Chapter 2. It would be the responsibility of the system operator to take whatever actions are needed to deliver the gas from where it enters the system to where it must exit the system.

The Southern Hub would feature a mandatory continuous balancing regime. Market participants would each have primary responsibility for their own balancing, and would have to maintain a balance between their cumulative supply and demand at those times that the system linepack becomes unacceptable. There would be financial incentives to do so, and gas could be traded at the virtual hub or sourced from a market participant's own portfolio, although all physical flows must be within the allowable capacity of the system.

The system operator would be responsible for residual balancing to maintain an appropriate system wide balance. If market participants were not collectively maintaining an acceptable balance between supply and demand despite their financial incentives, the system operator would be required to take residual balancing actions to restore an acceptable balance for the system as a whole. The costs of actions by the system operator would be recovered from those causing the need for residual balancing action.

The system operator would be responsible for undertaking a variety of other actions to maintain system security not related to system wide balancing. Situations may arise which would require action from the system operator to maintain system security which are not related to system wide balancing. For example, local linepack may be inappropriately low, even if the system wide linepack situation is within acceptable operating limits. The system operator would be responsible for undertaking actions which address these issues. The system operator would also be able to invoke emergency management procedures.

3.1 Balancing takes place at the virtual hub

For the purposes of balancing, the virtual hub would cover the transmission system with no distinction – gas injected at all entry and gas withdrawn at all exit points would be treated as being the same once inside the hub. This means that forward commodity trading at the Southern Hub could be used for balancing purposes, with market participants who have sold commodity before the day able to decide at which entry points it would be delivered on the gas day, subject to holding sufficient entry capacity.

This flexibility of delivery is likely to improve liquidity at the Southern Hub, as market participants would not be limited to offering and delivering commodity at a specific location – they would be able to choose suitable locations from within their commodity and capacity portfolios, or reduce their own demand in one location to meet an increase in demand elsewhere.

While a virtual hub is likely to promote liquidity, it does mean that the system operator would be required to manage gas flows in the transmission system to meet demand from wherever market participants choose to supply gas. In order to enable this:

- Market participants would be required to nominate supply and demand flows to entry and exit points, so that the system operator has sufficient information to manage flows across the system (discussed in section 3.2.5).
- Market participants' nominations at entry and exit points would be expected to be consistent with their capacity rights, which in turn would be consistent with the physical capabilities of the transmission system (discussed in section 3.2.5).
- The system operator would have a suite of tools at its disposal to ensure the transmission system remains secure, including residual balancing action (RBA), other system security actions, and emergency powers of direction (discussed in sections 3.3 and 3.5).

3.2 Mandatory continuous balancing

3.2.1 Mandatory balancing

Mandatory balancing means that each market participant has primary responsibility for maintaining a balance between their own supply and demand over time. This responsibility would be bestowed through financial and regulatory incentives to encourage market participants to collectively maintain the overall system balance within system security limits. If, as a consequence of these incentives, all market participants were individually to be in balance, the system would also be in balance.

The system would be able to absorb some level of imbalance. If, however, some market participants were to be sufficiently out of balance so as to affect the security of the overall system, the system operator would need to use the suite of tools available to take action to restore system security.

Financial incentives work most effectively when there is direct link of cost to cause, but this can be complex and costly to achieve. Regulatory incentives can stifle market participants' ability to manage situations flexibly, but are useful as a last resort when financial incentives are no longer effective. The design of an incentive framework must therefore be finely tuned to manage the trade-off between effectiveness and complexity.

3.2.2 The choice for continuous balancing

Some entry-exit markets require market participants to be exactly in balance at pre-defined points in time (e.g. daily[20]) or be subject to financial penalties, in order to ensure that the system as a whole remains in balance.

The disadvantage of this approach is that market participants are frequently incentivised to be in balance (and charged for not being so) despite this not necessarily being required for system security reasons. As a result, there is less efficient use of useable system linepack at the end of the balancing period, and can mean that more expensive commodity products are needed to restore balance within a limited timeframe.

This issue is exacerbated the shorter the balancing period, and hence the more frequent the requirement for market participants to be in balance.

Conversely, long balancing periods may result in the system becoming problematically out of balance because there are no incentives on market participants to be in balance within the period. This may be particularly the case in the DTS, which has the characteristic of limited linepack.

Given these considerations, the Commission recommends an alternative, continuous balancing approach should be adopted. Under such an approach, market participants would not be required to be in balance at any pre-determined time, but would be subject to residual balancing action charges if they were out of balance at the time when residual balancing action is taken by the system operator. Consequently, market participants would be able to carry forward an imbalance at any time, including between gas days, providing the system security was not threatened.

The advantage of the continuous balancing approach is that market participants are only incentivised to be in balance when system security is threatened. Linepack is efficiently used the rest of the time, and market participants are not (necessarily) required to arrange for responses overnight when they currently have limited ability to do so.

20 For example, most European markets including Belgium, Denmark and Great Britain have a requirement to be in balance at the end of the day.

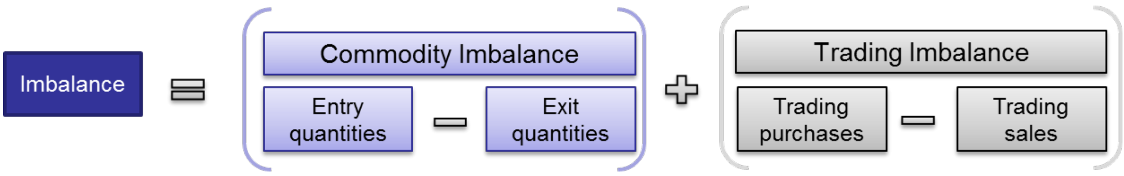
3.2.3 Market participant supply and demand

A market participant's imbalance would be defined as the difference between its supply and demand over a period of time. Supply would be defined as the total of entry quantities into the virtual hub plus trading purchases at the virtual hub (for which the selling market participant must increase entry quantities, reduce demand, or have sold an imbalance surplus). Conversely, demand would be defined as the total of all exit quantities from the virtual hub plus trading sales at the virtual hub.

Figure 3.1

Rearranging the above equation, this can also be thought of as the commodity imbalance plus trading imbalance over a period of time.

Figure 3.2



3.2.4 Matching supply and demand at the virtual hub

To be in balance, over time a market participant must match supply with demand. It could supply gas by:

- injecting gas from its own portfolio to the virtual hub;
- purchasing gas at the virtual hub before the gas day (for the gas day); and
- purchasing gas at virtual hub during the gas day.

Conversely, a market participant's demand is made up of:

- withdrawing gas from the virtual hub at controllable and uncontrollable exit points;
- selling gas at the virtual hub before the gas day (for the gas day); and
- selling gas at the virtual hub during the gas day.

A market participant selling gas at the virtual hub may do so by any combination of increasing injections from their own portfolio (within their available capacity rights), decreasing demand at exit points, or reducing an imbalance surplus already at the virtual hub.

3.2.5 Mandatory nomination to entry and exit points

While the system operator would know that trades have taken place at the virtual hub, it would not know the location of the physical flows resulting from those trades. To enable the system operator to securely manage physical gas flows on the virtual hub, market participants would be required to provide their expected supply and demand as hourly flows at specific entry points to and exit points from the virtual hub. This process is called nomination.

Nomination by market participants of hourly flows of gas to entry and exit points on a gas day would start ahead of the gas day, and would be timed to close after the close of forward trading. This would need to leave sufficient time for market participants to arrange for the physical gas flows outside of the hub, and the system operator to plan how it would securely operate the system to meet the entry and exit flows from all market participants.

Market participants would be able to update prospective nominations (i.e. for hourly flows starting after the beginning of the next hour) at any time. The updated nominations would need to take into account trading at the virtual hub during the day, any changes to injections of gas from a market participant's own portfolio, and any changes to demand. For example, a market participant would be able to transfer injections from one entry point by reducing nominations of hourly flows at the original entry point, and increasing them at the new entry point.

Market participants would be expected to nominate consistent with their entry and exit rights.[21] Because the number of entry and exit rights would be consistent with the physical capability of the system, in ordinary circumstances nominations should be able to be physically accommodated.

The system operator would use the most recent nominations as at the start of each hour to make any adjustment to system operations.

3.2.6 Monitoring market participant imbalances

For continuous balancing to work, market participants would need to be able to monitor their imbalances as the day progresses. In the Southern Hub, this would be known as their **position** (abbreviated as POS).

21 The most appropriate means to achieve this is likely to be that market participants would be prohibited from nominating in excess of their capacity rights. Alternatively, market participants could be penalised for nominating in excess of their capacity rights, such that the alternatives (purchasing capacity rights or not nominating above their rights) are generally preferable for the market participant. The Gas Market Reform Group should consider this matter further.

The system operator would determine each market participant's position hourly, and publish it shortly thereafter. The actual position would be published at the end of the previous hour, and projected positions for upcoming hours. Once an actual position is published it would not change (i.e. it is not updated retrospectively), as market participants would use this position to make decisions that manage their supply and demand.

Market participants would also need to know the overall state of the transmission system. This would allow them to choose to take corrective action if their position is significantly contributing to the cumulative imbalance and they are at risk of paying financial incentives. The cumulative imbalance is the **system balance signal** (abbreviated as SBS).

Market participants would be able to take action to restore their position to an acceptable imbalance by:

- changing injections of gas from their own portfolio at entry points;
- changing demand at controllable exit points; or
- purchasing shortfall or selling surplus gas at the virtual hub.

Alternatively, market participants would be able to choose to accept the imbalance and risk of financial impact if the system balance signal indicates that action by the system operator was unlikely, or that any actions would have a small financial impact.

To manage their position, market participants would need to be able to understand the potential for residual balancing actions, so that it could be averted if enough market participants were to adjust their supply and demand balance. Market participants would also need to know actual residual balancing actions already underway, as these would impact the system balancing signal in the future, and so would need to be taken into account by market participants when deciding whether to take further action.

A comprehensive information suite that segregates access to confidential information would be likely to be implemented with the Southern Hub balancing model, and which could include graphical interfaces and comprehensive data files. This is explained in more detail in section 3.4.

3.2.7 Determining market participant imbalance positions

A market participant's position would be determined for each hour. A relatively small number of meters (generally those for large consumers) may currently be sufficiently sophisticated for meter data to be available in this time, while for others, investment to improve meters may be justifiable.

However, because meter data for most meters is not currently available within an hour and upgrading such meters may be prohibitively expensive, an algorithm would be used to estimate, in near real time, the injections and withdrawals to be attributed to market participants with such meters. This estimate of injections and withdrawals is known as the near real time (NRT) estimated allocation.

The choice of algorithm for the near real time estimated allocations is a trade-off between accuracy, timeliness and cost. The higher the target accuracy, the higher the volume of data to be processed. This increases processing time and cost. Much of the information likely to be needed is currently available for the DWGM, so an algorithm to estimate allocations in near real time is technically feasible.

A market participant's position for an hour would be calculated as its actual position at the start of the previous hour, plus the near real time estimated entry allocations for the previous hour, less the near real time estimated exit allocations for the previous hour. Its projected position for subsequent hours would be based on its latest entry and exit nominations.

As a market participant's actual position for an hour would not be changed once published, a reconciliation process would address differences between a market participant's near real time estimated allocations and their actual entry or exit flows after six months.[22]

The Gas Market Reform Group should consider a reconciliation process to account for the difference between a market participant's near real time estimated allocation and their actual allocation determined after six months at, for example, the volume weighted average price for the gas day.

The near real time estimated allocation would be affected by late availability of custody transfer meter data. While estimates that were reasonably accurate could be used, the difference between the estimated and the actual meter data needs to be accounted for. Options for this include adjusting the most recent custody transfer meter data, or allowing the differences to be picked up in the reconciliation process.

A market participant's near real time estimated allocation would be affected if large distribution users change consumption behaviour – for example, by having an unexpected shutdown. The near real time estimated allocation could take account of this by either enabling real time manual consumption overrides[23] or by changing the meter reading frequency of the largest users from daily to hourly.

The Gas Market Reform Group should consider the detailed design of near real time estimated allocations to address issues such as the impact of changes to custody transfer meter data after the near real time estimated allocation and the metering requirements of the largest distribution network users.

22 A customer may transfer from one retailer to another retrospectively for up to business 118 days (approximately six months). I.e. a retailer can today register a customer transfer for a date that was 118 business days before today. Undertaking the reconciliation process after six months means that consumption would be appropriately allocated to the correct retailer. AEMO, *Retail Market Procedures (Victoria)*, version 11, September 2016.

23 The market participant would provide override estimates via an online interface.

3.2.8 Market participant positions are carried over to next day

Continuous balancing means that market participants would be able to choose to have an imbalance carried from one gas day into the next, and the system operator would ensure that overall the transmission system remains secure. This means market participants would not have to trade gas to achieve a neutral position by the end of each balancing period – instead they could use the next gas day to restore their position by trading or using their own portfolio.

In Victoria, demand is very typically concentrated in approximately the first half of the gas day (between 6am and ending in the evening) and entry flows uniformly over the full gas day. This can mean linepack is typically significantly depleted by the evening peak if the overall transmission system was not reasonably in balance at the start of the day. To encourage market participants to minimise their imbalance carried from one day to the next, a linepack usage charge could be applied to those market participants who carry an imbalance from one gas day to the next. This could improve liquidity at the virtual hub as market participants sought to avoid a linepack usage charge – particularly if the rate for this was set relatively high or even linked to the price index for the day.

A further option that could be considered is a mandatory 'cashing out' of all (or a portion) of market participants' imbalances at the end of the day – to concentrate liquidity around intraday products. However, this would detract from the benefits of continuous balancing approach described in section 3.2.2.

Both the linepack usage charge and a mandatory 'cashing out' of end of day imbalances would provide incentives to minimise imbalances at the end of the day, and promote liquidity at the virtual hub – particularly swaps of gas between participants who are long and participants who are short of gas. The aggregate position of long market participants is rarely likely to equal the aggregate short position of other market participants, meaning that swaps alone would rarely be sufficient to return all market participants to being in balance. This is likely to mean that the 'cashing out' option would require some purchases or sales of additional gas injected into or withdrawn from the hub, and could lead to higher prices late in the day.

The 'cashing out' option would reduce each market participant's position back to zero at the end of the day via a forced sale or purchase by the system operator, whereas the linepack usage charge option would allow market participants to choose to carry forward an imbalance. An imbalance carried forward to the next day could be sourced from trading at the virtual hub (both before the day and on the day) or from a market participant's own portfolio which might be a more economically efficient outcome.

The Gas Market Reform Group should consider the alternative approaches to providing incentives to market participants to minimise their end of day imbalance position, and whether they could be introduced as permanent or transitional measures.

3.2.9 Managing continuous balancing

Given its responsibility to maintain a balance between supply and demand (at those specific times when system security was threatened), a market participant would be responsible for managing its interday and intraday positions.

This would involve a range of activities before and during the gas day as set out in Box 3.2.

Box 3.2 Activities undertaken by market participants to manage their position

Before the gas day:

- procuring forward gas and capacity portfolio; and
- comparing forward products on offer with current portfolio holdings to decide if using portfolio or purchased products.

Nearer the start of the gas day:

- understanding likely imbalance position to be carried forward to next day, the likely costs of accepting this, and benefits of taking action to reduce imbalance;
- more accurately forecasting demand on the following day, deciding on deployment of portfolio or purchasing on trading platform; and
- nominating to entry and exit points.

During the gas day:

- updating demand forecast and making decisions on redeployment of portfolio and/or trading at virtual hub to buy shortfalls or sell surpluses; and
- monitoring the system balance signal to estimate likelihood of residual balancing action, the likely cost and share of costs if this happens, and deciding to either accept possible share of costs or adjust supply and/or demand.

3.3 Residual balancing by system operator

If market participants were collectively out of balance to the extent that the system wide balance was to be affected, the system operator would be required to take action to ensure the system remains secure. This would be a transparent process by which the system operator would take action to purchase or sell gas at the virtual hub to restore system wide security. This is known as **residual balancing action** (RBA).

The residual balancing process would include defining the linepack limits at which the system is secure over the gas day, monitoring the state of the system against those limits, taking targeted action when the limits are exceeded and reporting to market participants.

3.3.1 Residual balancing bands

The system operator would define the linepack limits at which they would take residual balancing action. These are known as **residual balancing bands** (RBB).

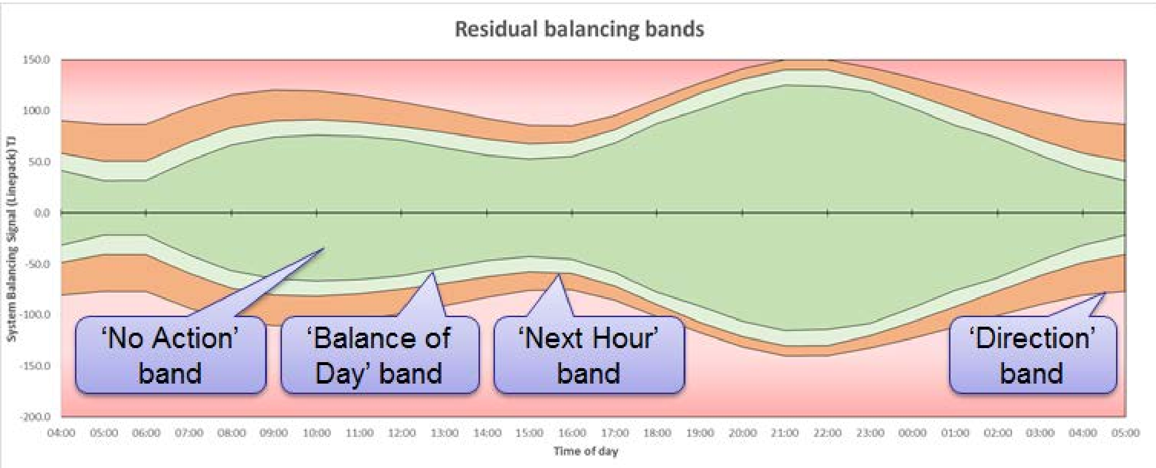
Setting the limits is a trade-off between the system operator taking action unnecessarily early, when market participants would have individually resolved their own out of balance positions, and too late, when residual balancing costs may be higher than they would otherwise have been. Residual balancing bands would be defined before the start of the day to provide market participants sufficiently timely information to manage their balancing actions, and would be likely to be based on a number of factors such as the physical capability of the system on the day.

Residual balancing bands could cover progressive, predefined actions for the system operator to undertake. For example, the bands might be defined as follows:

- 'do nothing' – market participants are collectively sufficiently in balance;
- buy / sell commodity at virtual hub over balance of day ('balance of day');
- buy / sell commodity at virtual hub over next hour ('next hour'); and
- directions to inject / withdraw ('directions').

This possible approach is illustrated diagrammatically in Figure 3.3.

Figure 3.3 Example of possible residual balancing bands



The size of the residual balancing bands varies according to the time of day. For example, all residual balancing bands at the start of day are narrower. This is because linepack gets depleted during the morning and evening peak demand periods, and if it is low at the start of day there is a risk that it would not be replenished by the start of the evening peak demand period. Similarly, the 'do nothing' band is at its maximum during the evening peak, to allow the maximum amount of linepack to be used.

The rationale behind the continuous balancing model is that the most likely system operator action would be 'do nothing' – it is only when the system is becoming less secure that further action would be taken.

Box 3.3 Comparison with the DWGM

In the DWGM, the end of day linepack target model means the system operator is rarely in 'do nothing' mode. Instead, it is mostly in 'balance of day' mode as it aims to reach an end of day linepack balance target. This can lead to buying in one scheduling interval and selling in a later interval as the system operator takes action to buy/sell linepack, and market participants take action by changing their demand forecast.

Buying or selling gas from linepack in the DWGM has an impact on marginally priced injections or withdrawals at controllable points. This can impact market participants who:

- may have more or less gas delivered than anticipated, leaving them with imbalances in other markets or facilities; or
- are charged negative ancillary payments when previously scheduled injections cannot be de-scheduled when system operator sells linepack.

3.3.2 System Balance Signal

To decide what action needs to be taken, the system operator would need to know the system's available linepack.[24] This is known as the system balance signal (SBS), introduced in section 3.2.6 in the context of market participants deciding whether to take balancing action.

The system balancing signal would either be an actual system balance signal (for an hour), or a projected system balance signal (for subsequent hours). The actual system balancing signal is calculated from the system's available linepack. The projected system balancing signal for subsequent hours is calculated from the actual system balancing signal plus the sum of all market projected participant's positions.

The system linepack provides an indicator of the overall system balance. Using the actual system linepack means all factors that affect the system balance (including entry and exit flows, compressor usage, and unaccounted for gas (UAFG))[25] are taken into consideration.

24 Using the system's available linepack for this purpose would be appropriate as some of the total linepack (calculated based on pipeline size, pressures and energy content of the gas) cannot be used for operational reasons.

25 UAFG is the difference between gas measured into and out of a system over a period of time after accounting for linepack changes during the period. UAFG is due to many factors, the foremost of which is measurement uncertainty.

The system balancing signal would then be compared with the residual balancing bands to determine if the system operator needs to take action. As noted in section 3.4, the system balancing signal would need to be published to market participants, who would compare it with their own published position to determine the likelihood of residual balancing action, and their likely share of any residual balancing action costs, so they can monitor the effectiveness of their own continuous balancing actions and adjust them if necessary.

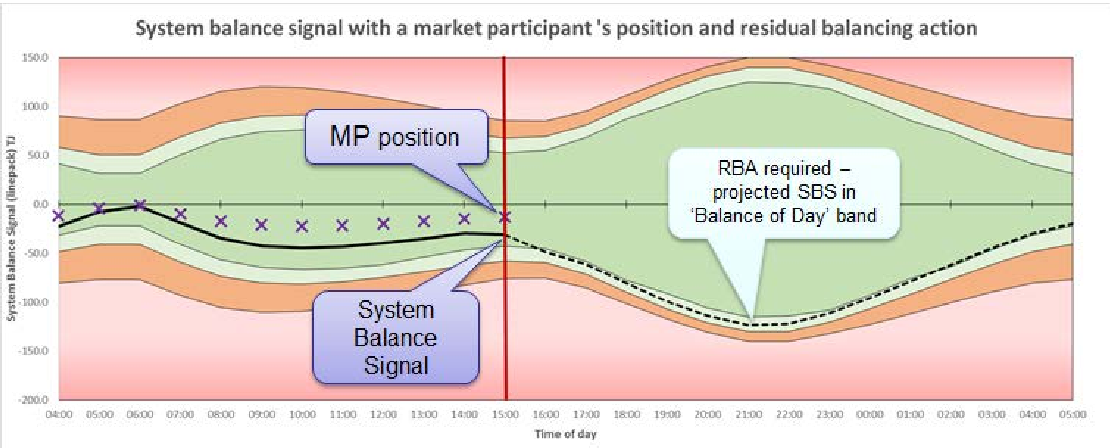
3.3.3 Residual balancing action by system operator

The system operator would need to take residual balancing action if market participants collectively were not to have maintained the overall system balance within necessary limits. This would happen when the system balance signal moves beyond the 'do nothing' band.

The need for residual balancing action at a given time could be determined based on the actual system balance signal at the time, or on the projected system balance signal. The time taken by gas to move from entry points (other than Dandenong) to the major exit points in the DTS might imply a need to base residual balancing actions on the system balance signal projected forward by a number of hours. However, it may be possible to use the actual system balance signal or a shorter-term projection if the system balance bands were set on a tighter basis to reflect the added uncertainty. The detailed design phase should assess the relative merit of these approaches.

The quantity of a given residual balancing action would be set to recover the system balancing signal to the extremity of the next most satisfactory residual balancing band – for example, a 'balance of day' action would return the system balance signal to the 'no action' zone boundary. This is illustrated in Figure 3.4.

Figure 3.4 Example of residual balancing action when system balancing signal is projected to leave 'no action' band



When taking residual balancing action, the system operator would be required to buy or sell linepack at the virtual hub using the exchange. As it would be buying or selling gas at the virtual hub, it would not require entry or exit rights. Instead, to effect a change in the system balancing signal the system operator's counterparty would inject or withdraw gas to or from the virtual hub, consistent with the counterparty's entry or exit rights.

By using the exchange, liquidity in the intra-day balancing market would be promoted:

- A separate, system operator specific trading platform or product as has been used in other markets might dilute trades on the exchange.[26]
- The bids/offers made by the system operator would be available for use by other market participants to enter into in order to maintain their own individual positions.

To change the system balancing signal, a residual balancing action must result in a change to entry or exit flows. If the system operator were to buy gas at the virtual hub from a market participant who had a surplus of gas in the hub, it would reduce the market participant's surplus but would not change the system balance signal. The Gas Market Reform Group should determine whether it is appropriate for the system operator to be able to differentiate between physical products that would change linepack (change entry or exit flows at any point) and those that are imbalance swaps (affect each market participant's position, but does not require a change in entry or exit flows), and purchase only the former in order to affect the system balancing signal.

By avoiding buying imbalance swaps, the system operator may be able to effect more timely, effective and low cost system balancing, because it would not unnecessarily purchase gas which has no effect on the system as a whole. However, such an approach may have downsides. For example, any division in the products on the exchange may dilute liquidity. Furthermore, it may create unwanted incentives on market participants which would otherwise be able to trade their gas already in the system with the system operator. For example, if the system is short but a market participant is long of gas, the market participant may choose to reduce its injections (putting the system further out of balance) in order to be able to then subsequently sell the gas it withheld to the system operator.

In practice, it may be that little gas would be available for an imbalance swap when residual balancing action was needed, because:

- any market participant in surplus would have the effect of reducing the system imbalance and thus the likelihood of the system operator having to take action; and
- market participants which are facing the prospect of residual balancing action costs would be incentivised to try to return to being in balance prior to the residual balancing action being undertaken, and so bid to buy (or offer to sell) gas, at reasonably high (low) prices. These prices may be sufficiently attractive

26 The Netherlands balancing regime initially featured a separate bid ladder for residual balancing actions, but this has now been replaced with title trading products at the virtual hub.

that counterparties with gas already in the system choose to trade, effectively entering into swaps prior to the residual balancing action being undertaken.

The market participants allocated a portion of the costs of a residual balancing action would also be allocated a proportional quantity of the gas bought or sold as a trading purchase or sale – in other words this would be counted in their imbalance in subsequent hours as the gas flows.

3.3.4 Cost recovery for residual balancing actions

The total costs incurred by the system operator for each residual balancing action would be recovered from those market participants who are out of balance (in the same direction that the system is out of balance) at the specific time that residual balancing action is taken, such that they have contributed to the need to take action.

In principle, the costs of residual balancing action by the system operator should be recovered from those market participants causing system wide imbalance. This provides incentives on market participants to manage balancing in accordance with the physical requirements of the system.

However, there is a trade-off between cost-to-cause and complexity. The more costs are accurately allocated between market participants, the more complex the design and more costly the required market systems. A more complex market design also increases the risk that an overlap of scenarios creates an unusual outcome.

Conversely, a less complex design may provide incentives for market participants to minimise their own exposure at the expense of the system (and so other market participants).

A simple approach to residual balancing action cost recovery would be to recover total costs (or refund total revenues if the system was long) from all market participants with a position of the same sign as the system balancing signal at the time the system operator balancing actions are initiated, in proportion to their positions, i.e.:

- the total cost of residual balancing actions; multiplied by
- the individual market participant’s position of same sign as system balancing signal; divided by
- the sum of all market participants’ position of same sign as system balancing signal.

More complex approaches could also be applied, including but not limited to those described below. The Gas Market Reform Group should examine whether such approaches appropriately trade-off cost-to-cause with complexity.

Box 3.4 Example – cost allocation of residual balancing action

- The system as a whole was short of gas, such that the system balancing signal was negative, and forecast to enter into the 'balance of day' band.
- Consequently, the system operator undertook residual balancing action, purchasing 3,600GJ of 'balance of day' gas to get the system to the extremity of the 'no action ' band.
- The cost associated with this residual balancing action was $20,000.
- There were three market participants:
  - market participant A had a position of -6,500 GJ;
  - market participant B had a position of -3,500 GJ; and
  - market participant C had a position of +1,000 GJ.
- Residual balancing action costs were assigned as follows:
  - market participant A: $20,000 x 6,500 / (6,500+3,500) = $13,000;
  - market participant B: $20,000 x 3,500 / (6,500+3,500) = $7,000; and
  - market participant C was not assigned any cost because it was long, while the system as a whole was short.
- Gas purchased as a result of the residual balancing action was assigned in the same ratio, as follows:
  - market participant A: 3,600 x 3,500 / (6,500+3,500) = 2,340 GJ, resulting in an end position of -4,160GJ;
  - market participant B: 3,600 x 3,500 / (6,500+3,500) = 1,260 GJ, resulting in an end position of -2,240GJ; and
  - market participant C was not assigned any gas because it was long, while the system as a whole was short.

Recovery of marginal residual balancing action cost

Charges levied on those market participants that cause residual balancing actions could be set on the basis of the cost of the marginal residual balancing action undertaken. Unlike using the average cost, this would mean that AEMO would over-recover revenue. Over-recovered revenue could be used to offset other costs incurred by AEMO or market participant fees. This approach may be preferred if stronger incentives are needed for market participants to be sufficiently in balance such that system security was not threatened.

Taking the example above, the $20,000 of residual balancing action costs could have been made up of a purchase by AEMO of 3,000GJ at $5/GJ and 600GJ at $8.33/GJ. AEMO would then recover $30,000 (3,600GJ at the marginal price of $8.33/GJ). Market participant A would pay $19,500 and market participant B would pay $10,500.

Payment to participants with a position opposite to the system balancing signal

Under this approach, the market participant would purchase enough gas to return:

- the system to the extremity of the next most satisfactory residual balancing band; and
- all market participants with position opposite to the system balancing signal to being in balance.

In the example above, AEMO would purchase 4,600GJ of gas (3,600GJ to return the system to the extremity of the next most satisfactory residual balancing band, plus 1,000GJ to return market participant C to being in balance).

Such an approach may be appropriate because it recognises that market participant C was assisting the system and hence reducing residual balancing action costs. In the example, had market participant C not been 1,000GJ long but, instead, been in balance, AEMO would have needed to purchase 4,600GJ and recovered costs associated with this purchase from market participants A and B.

However, this approach is more complex, and also requires market participant C to be involuntarily cashed out.

Allocating costs where a market participant's imbalance exceeds expectations

Because the intraday demand profile in Victoria peaks during the morning and evening periods, it is expected that linepack usage would be at a maximum at these times. This is the expected intraday linepack profile, and market participants are able to use the linepack without penalty while it remains in the 'do nothing' limits.

If a market participant nominated exit flows significantly outside the expected intraday profile such that residual balancing action is taken, then they might be considered to be the "causer" of that action. However, under the simple approach described above, all market participants contributing to the linepack usage at that time would be allocated a share of the costs – even if they were only using linepack consistent with the expected intraday linepack profile. Put another way, all retailers that are short of gas at the evening peak, but no more so than usual, would be penalised if one market participant was shorter than usual, causing residual balancing action.

Market participants could have an incentive to avoid nominating inconsistent with the expected intraday profile if they were allocated an increased share of residual balancing action costs. For example, market participants could be allocated a share of available linepack, with all costs (or a proportion of them) allocated only to those market participants who were using more than their share.

Among other complications, this approach would require consideration of what the share of linepack would be for each market participant, and how to treat market participants who have a profile that is not diurnal (e.g. factories, which tend to have flat withdrawal rates).

3.4 Information to support balancing

Market participants would be individually responsible for maintaining their balance position. To do so they need to be able to see if there are potential or actual residual balancing actions. A potential residual balancing action may be averted if enough market participants adjust their supply and demand balance, and an actual residual balancing action would mean that market participants should take the system operator's actions into account when deciding if they need to take further action.

A comprehensive information suite is likely to be implemented with the Southern Hub balancing model, which could include graphical interfaces and data files for:

- residual balancing bands;
- actual and projected system balance signal;
- individual information for market participants (accessible only by relevant market participant):
  - their imbalance position relative to the system balance signal and aggregated 'causer' market participants;
  - nominations by entry and exit points; and
  - capacity holdings by entry and exit points;
- residual balancing action taken by system operator;
- aggregated data across all market participants:
  - total imbalance position for 'causer' market participants relative to system balance signal;
  - total nominations by entry and exit points;
  - nominated and available firm capacity by entry and exit points; and
  - available interruptible capacity by entry and exit points;
- traded prices and quantities of commodity at virtual hub and capacity at relevant entry/exit points;

- index prices; and
- emergency and system wide notices.

As with existing market information systems, access to confidential information would be restricted to the relevant market participant. It is also likely that related market participants would be able to group information to have individual and group views.

3.5 Other actions to maintain system security

The balancing regime described in this chapter seeks to allocate costs to market participants who, by being out of balance, cause the system as a whole to be out of balance such that the system operator needs to take residual balancing action. In doing so, it would incentivise market participants to individually remain sufficiently in balance, so that collectively the system as a whole is sufficiently in balance such that system security was not threatened.

However, maintaining system wide balance would not be the only system security consideration for the system operator. For example, linepack at a specific location in the system might approach becoming inappropriately out of balance, even if the system balancing signal was within the 'do nothing' balancing band. This could arise, for example, because market participants change their nominations without sufficient warning for the system operator to adjust flows within the system, or because market participants fail to inject or withdraw in accordance with their nominations.

Box 3.5 provides further explanation of how these actions could cause costs to manage system security.

Box 3.5 Late (re)nominations or flows not in accordance with nominations

Normally, the system operator would manage the system to deliver gas from nominated entry points to nominated exit points. If market participants only make (or change) nominations close to the time the flow is required (nominating late), or do not flow gas in accordance with its nominations, the physical properties of gas and the transmission system can limit the system operator’s ability to manage delivery of the nominated gas.

For example, if a market participant increased exit nominations for the next hour, the increased withdrawals could deplete linepack locally before the system operator could arrange for additional gas at that location.[27] If the market participant had increased entry nominations by the same amount, the market participant would not have changed their imbalance position and the system balancing signal would remain unchanged, despite the localised linepack issue.

27 By managing compressor usage, and regulating pressures in the transmission system.

In these instances, the system operator may need to take a variety of system security actions, such as:

- buying or selling gas through the exchange at specific locations (e.g. from the Dandenong liquefied natural gas facility) which can address local linepack issues; and
- through a market process, buying back capacity rights from market participants, so that they reduce their injections at that location.

For example, if a minimum flow rate is needed at the Iona entry point to support maintenance activities and these flows were not otherwise being nominated by market participants, the system operator could issue a notice that it would be placing a buy request for the shortfall on the trading platform for Iona delivery at a set time in the future. The trading platform would need to have products available for this purpose at all controllable entry and exit points.

While appropriate in certain specific circumstances, these actions would be undesirable for returning system-wide linepack to the do-nothing band because they might not be the cheapest option available to the system operator to resolve system wide linepack issues.

The principle articulated in section 3.3.4, whereby the costs of residual balancing action by the system operator should be recovered from those market participants causing system-wide imbalance is a specific case of a more general principle: the costs of actions undertaken by the system operator to maintain system security should be recovered from those market participants causing the issue.

In the existing DWGM, costs to maintain system security are recovered as surprise uplift and congestion uplift charges, with any un-attributable costs being recovered as common uplift.

Under the Southern Hub arrangements, congestion uplift would largely be replaced by the system of entry and exit rights: the baseline level of capacity released (described in chapter 4) should not commonly cause congestion to arise because firm baseline capacity rights would be allocated consistent with the underlying physical capacity of the system, and above baseline capacity rights would be released on an interruptible basis.[28] In addition, proceeds from the sale of above baseline capacity, overrun charges received from participants and the proceeds of any financial incentives on the DTS service provider to make baseline capacity available could all be used to fund system operator actions to manage specific system security issues.

However, the 'target' model described in this report does not currently contain any charging mechanism equivalent to surprise uplift in the current market. There is a trade-off between attributing cost-to-cause and complexity. The more costs are accurately allocated between market participants, the more complex the design and more costly the required market systems.

28 There would be no costs associated with curtailing interruptible capacity.

The Commission recommends the Gas Market Reform Group, in undertaking further design work and market trials, should examine:

- the likely magnitude of costs associated with the short-term variation of nominations, and consider whether it would be preferable to socialise these costs or design and implement a further charging mechanism to allocate these 'surprise' costs to causers; and
- the need for, and design of, products suitable for use by the system operator for system security issues not related to system wide linepack (for example location specific gas).

The Commission may also consider these matters further prior to the completion of the Final Report for this review.

3.5.1 Emergency management

Emergency situations on the transmission pipeline, at connection points and at connected facilities that impact on the system operator's ability to maintain system security may arise from time-to-time. In these situations, the residual balancing action of the system operator or the other actions to maintain system security described above may be inappropriate tools to maintain system security.

In these situations, the system operator would be able to invoke emergency management procedures and direct market participants in order to maintain system security in a similar manner to the current DWGM arrangements.

Table 3.1 Summary of required, preferred and suggested features of the Commission's recommendations

	Required design features	Preferred design features	Suggested design features
Recommendation 2: Each market participant would have financial incentives to balance its own supply and demand position under a mandatory, continuous balancing mechanism. The system operator would be responsible for ensuring system security. This would include a residual balancing role where market participants are not collectively sufficiently in balance to maintain system security.			
Continuous balancing	• Each market participant would have primary responsibility for maintaining a reasonable balance between their own supply and demand during a gas day, and between one gas day and the next. • There would be financial and regulatory incentives to encourage market participants to remain in reasonable balance. • Market participants would not be required to be in balance at any pre-determined time, but would be subject to residual balancing action charges if they were out of balance at the time when residual balancing action is taken by the system operator. • Market participants would nominate their expected injections and withdrawals as hourly flows at specific locations on the virtual hub and notify the system operator of any trades undertaken at the virtual hub.	• Market participants would be able to choose to have an imbalance carried from one gas day to the next.	

	Required design features	Preferred design features	Suggested design features
	• The system operator would determine each market participant's imbalance position hourly, and publish it shortly thereafter. • A near real time (NRT) allocation methodology would be used to determine each market participant's imbalance position. • There would be a reconciliation process to account for the difference between a market participant's NRT allocation and their actual allocation determined after six months. • There would be comprehensive information provision to market participants to enable them to monitor their imbalances and other market parameters.		
Residual balancing	• The system operator would take residual balancing action if market participants are collectively out of balance to the extent that system security is affected. • The system operator would set the linepack limits at which it would take residual balancing action before the start of every gas day. • The system operator would determine		• A projected system balance signal would be used to determine the need for residual balancing action.

	Required design features	Preferred design features	Suggested design features
	and publish an hourly system balance signal. • The system operator would take progressive residual balancing action if the system balance signal exceeds the linepack limits during the day. • The system operator would take residual balancing action using the trading exchange at the virtual hub. • Market participants who have contributed to the need for a residual balancing action would be allocated a portion of costs for residual balancing action, and a portion of the gas that was bought or sold.		
Management of system security and emergencies	• The system operator would be responsible for undertaking a variety of actions to maintain system security not related to system wide balancing. • The system operator must establish emergency management procedures to manage emergency situations affecting the Southern Hub that are consistent with arrangements for the DWGM. In accordance with these emergency management procedures, the system operator may make directions to market participants to maintain system security.	• Actions that the system operator would take to maintain system security not related to system wide balancing include: — buying or selling gas through the exchange at specific locations; and — buying back capacity rights from market participants.	

4 Pipeline capacity

Box 4.1 Recommendations

Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.

Capacity trading under the Southern Hub model would have the following features:

1. **Determination of the amount of baseline capacity to be released:** carried out through a transparent process, with the DTS service provider proposing the level of baseline capacity and the AER approving such level after consultation with industry participants.
2. **Standardised capacity products:** to facilitate trade in both primary and secondary capacity that best meet the needs of market participants.
3. **Primary baseline capacity to be allocated:**
   (a) at distribution connected exit points, using a dynamic allocation mechanism; and
   (b) at all other entry and exit points, through the use of short and long term auctions.
4. **Above baseline capacity:** released through a day-ahead and/or within day auction, with capacity rights to be offered on an interruptible basis.
5. **Measures to encourage the release of secondary capacity:**
   (a) a short-term use-it-or-lose-it (UIOLI) mechanism for contracted but un-nominated baseline capacity at points with contractual congestion, which would be released to the market through a day-ahead auction after the nomination cut-off time; and
   (b) the development of an electronic exchange that would enable market participants to trade secondary capacity on an anonymous basis.
6. **Investment in new baseline capacity:** at distribution connected exit points should be signalled through the existing bilateral planning process. At other points expansions should, where feasible, be signalled through a market-based mechanism, with the Commission's preferred mechanism being the hybrid open-season integrated auction.

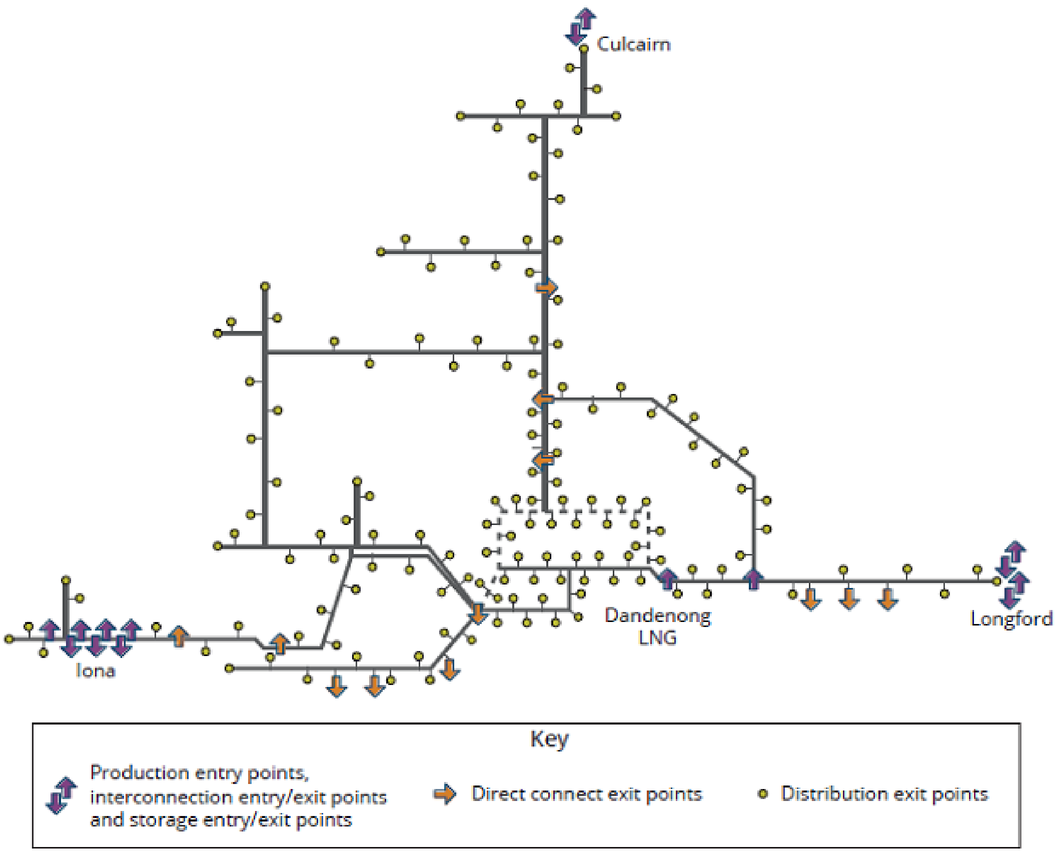
To give effect to various aspects of the entry-exit model, a number of changes would need to be made to the economic regulatory framework in the NGR and, potentially, the NGL.

4.1 Introduction and context

As mentioned earlier in the report, concerns have been raised that perceived complexity in the DWGM may be impeding market entry, risk management practices (including the emergence of risk management products), and efficient investment. In particular, the Reith Review suggested that the difficulty in obtaining firm capacity and the need to manage 'unhedgeable' price risks may have led some gas-fired generators to decide not to connect to the DTS.[29] The Commission's recommendations on pipeline capacity, combined with those elsewhere in this report, aim to address these issues.

To support the new form of trading and balancing that would occur under the Southern Hub model and facilitate market-led investment in the DTS, the Commission is recommending that the market carriage model and limited transportation rights[30] in the DTS be replaced with explicit, tradeable capacity rights for entry and exit to the DTS.

Figure 4.1 Existing entry and exit points in the DTS



Notes: There are currently 4 production entry points, 4 interconnection entry/exit points, 2 storage entry/exit points, 12 direct connect exit points and 111 distribution exit points.

29 Victorian Government, *Gas Market Taskforce: Supplementary Report*, October 2013, p. 80.

30 Authorised maximum daily quantity (AMDQ) and AMDQ credit certificates (AMDQ cc).

The entry-exit system, which is widely used in markets throughout Europe with a wide variety of characteristics, would allow market participants to obtain firm and interruptible capacity rights independently at entry and exit points in the system through transparent and non-discriminatory capacity release mechanisms. In contrast to the contract carriage model, gas in the entry-exit model does not follow a predefined contractual path, which is why entry and exit rights can be obtained independently. The term 'entry point' is used in this context to describe a point where gas is injected into the transmission system, while an 'exit point' is a point where gas is withdrawn from the system. The DTS has a number of such points, some of which operate as both entry and exit points, while others operate as just an entry point or just an exit point. The locations of these points are set out in stylised form in Figure 4.1 above.

Under the proposed entry-exit system, a market participant wanting to inject gas into, or withdraw gas from, the DTS would have to hold sufficient entry and/or exit capacity.[31]

Specifically, a market participant would be able to acquire capacity on a firm basis (baseline capacity), which the DTS service provider would be responsible for making available. It may also be able to enter into a secondary trade with another participant. If all the baseline capacity was sold, the market participant may be able to acquire capacity on an interruptible basis from 'above baseline' capacity, which AEMO, as system operator, would be responsible for releasing.

If additional investment in baseline capacity was required at an entry or exit point then, where feasible, market participants would be able to signal their need for capacity through a market based investment mechanism.[32]

The Commission expects the movement to this new system of capacity rights to:

- allow for the trading of forward physical products through the Southern Hub, providing market participants alternative approaches to better manage their risk;
- enable pipeline capacity to be allocated in an efficient, transparent and non-discriminatory manner;
- promote more timely and efficient market-led investment throughout most of the DTS; and
- continue to provide for the efficient operation of the DTS.

To implement the entry-exit system, changes would need to be made to the DWGM related provisions in the NGR and, potentially, the NGL. Some refinements would also need to be made to the economic regulatory framework that currently applies to the

31 Market participants wishing to solely trade gas products at the Southern Hub prior to their delivery date (e.g. financial traders) would not require entry and/or exit capacity so long as they closed out their physical positions prior to delivery.

32 Any new capacity would only be available after a certain lead time, taking into account the mechanisms explained in section 4.5 and the necessary construction time to make new capacity available.

DTS, which would also require additional functions to be added to the NGR and may require changes to the AER's functions as set out in the NGL. Overall, however, only minimal changes to the regulatory framework are expected to be required, and the rationale for regulating the DTS and the overarching objectives of regulation, as defined in the National Gas Objective (NGO), would be unchanged. The level of regulatory oversight would also be unchanged, with the AER retaining responsibility for approving the DTS service provider's revenue requirement and reference tariffs for entry and exit capacity.

Further detail on the proposed entry-exit system is provided in the remainder of this chapter, which commences with an overview of how the level of baseline and above-baseline capacity would be determined and then focuses on:

- the capacity products that would be made available for sale at each entry and exit point;
- the capacity allocation and release mechanisms that would be employed for baseline and above baseline capacity, and the measures that would be used to encourage secondary capacity trading;
- the mechanisms that would be used to signal the need for new investment and allocate new baseline capacity; and
- the implications of the proposed changes for the economic regulatory framework.

The final section of this chapter contains a summary of the Commission's recommendations, which have been categorised as:

- **required** outcomes, which are necessary outcomes that the GMRG should be tasked to develop a package of regulatory changes to deliver;
- **preferred** outcomes, which the GMRG should pursue unless it is clear that there are greater benefits in alternative approaches; or
- **suggested** outcomes, which should be considered by the GMRG given the in-principle benefits that may arise from their implementation.

Before moving on, it is worth noting that the entry-exit system is used in many European countries and while the Commission is conscious of the differences between the gas markets and institutional arrangements in these countries and those in Victoria, there are some useful lessons that can be drawn from their experience.

4.2 Calculation of amount of capacity to be released

A capacity right under the entry-exit system would provide market participants with a right to inject or withdraw gas at specific entry or exit point. Clearly, to exercise this right, the amount of capacity available would have to be consistent with the physical capacity of the DTS.

The DTS is a complex, meshed network. Consequently, the amount of capacity physically available at each entry and exit point varies on a day-to-day basis, in response to a number of factors, such as: pipeline infrastructure, system wide and local linepack, operating considerations, such as maintenance and outages, and demand location and the profile of demand.

The nature of many of these factors means that it is difficult to accurately forecast, well in advance, the amount of capacity that would be physically available. For example, amongst other things, demand for gas in the DTS is a function of the weather and demand from gas fired generation. Consequently, even though the amount of capacity available can be forecast with reasonable certainty immediately before the gas day, the further ahead the capacity level is forecast, the greater the uncertainty.

Given this uncertainty, determining the appropriate amount of capacity rights to be released involves the following trade-offs:

- issuing more rights than are physically available (which means they cannot all be simultaneously honoured) and issuing less rights than are physically available (which risks under-utilising the network); and
- issuing rights too early (which risks allocating an inappropriate amount of rights based on inaccurate forecasts - either too many or too few) and issuing rights too late (which risks market participants being unable to plan on the basis of, and is unlikely to engender long-term market led investment).

In order to address these trade-offs, the Commission is recommending that:

- an amount of capacity that is highly likely to be physically available regardless of the circumstance be calculated and released well ahead of time (e.g. over the 5 year period of an access arrangement). This would provide market participants with early access to capacity. Because of the high degree of confidence that the capacity would be physically available, this capacity should be released on a firm basis, providing market participants with confidence that they are unlikely to be constrained (and with financial compensation in the event of a constraint). Capacity released in this manner is known as “baseline” capacity; and
- additional capacity be released on a day-ahead basis, based on more accurate forecasts at that time of physically available capacity. This would mitigate against the network being under-utilised. Capacity released in this manner would be done so on an interruptible basis and is known as “above baseline” capacity.

4.2.1 Calculation of baseline capacity

As outlined above, the methodology used to calculate baseline capacity is important because it would determine the amount of firm capacity which must be made available in advance by the DTS service provider at each entry and exit point to and from the system. That said, setting the level of baseline capacity can be particularly challenging in a system that exhibits high unpredictable flows like the DTS.

The amount of baseline capacity would ideally be determined with the aid of load flow modelling software, taking into account the various factors that affect the availability of capacity, such as pipeline infrastructure, system wide and local linepack, operating considerations such as maintenance and outages, and demand location and profile. In addition, the model should reference a pre-defined probabilistic standard for whether the capacity is physically available. For example, capacity could be calculated and released with a probability that it could not be physically met one day in every twenty years. It is worth noting in this context that this approach is similar to the approach that is currently used to determine the availability of AMDQ and AMDQ cc.

The Commission also suggests that baseline capacity be defined on a seasonal basis in order to maximise the release of firm capacity during the year (i.e. instead of baseline being set as a fixed annual amount for a particular entry or exit point, it could be fixed as a quarterly amount, giving the chance to market participants to match their booking of capacity more closely to their demand profile).

The Commission recommends a transparent process be employed to determine the amount of baseline capacity to be released, with the DTS service provider proposing the level of baseline capacity and the AER approving such level after consultation with industry participants, including AEMO.

The Commission envisages that this process would occur as part of the Access Arrangement review process because the setting of the baseline capacity would have important implications for other aspects of the AER's regulatory decision-making, including:

- defining the maximum capacity that the DTS service provider can recover its revenue requirement from;
- future investment decisions, because if baseline capacity is set too low the market may demand further expansions to enable them to obtain firm rights;
- any incentive scheme that the AER may decide to introduce to encourage the DTS service provider to make baseline capacity available; and
- the level of firm capacity that can be offered to market participants and the extent to which congestion management costs are likely to be incurred.

The Commission is of the view that the AER's role in this process is consistent with its economic regulatory functions under the NGL and the AER is the most appropriate body to take on this task, particularly given the linkages to the Access Arrangement review process. It is also worth noting that in Europe, the economic regulators are also responsible for approving the baseline capacity levels.

An overview of how baseline capacity is determined by National Grid in Great Britain is provided in the box below, which provides some insight into how this process could be implemented in the DTS.

Box 4.2 Determination of the baseline capacity of National Grid's National Transmission System

In Great Britain, the establishment of baseline firm capacity involves the regulator, Ofgem, setting defined quantities of capacity at entry and exit points, to and from, the National Transmission System (NTS). Importantly, baselines are not set in isolation, but are determined as part of the wider Transmission Price Control Review. Once set, Ofgem fixes baselines over the relevant price control period, which has historically been five years.

The NTS is a complex gas transmission system and in order to support the analysis required for setting baselines, the use of network analysis software is required. SIMONE (SIMulation and Optimisation of NEtworks) is a detailed mathematical model of the NTS, which is used to understand the likely flows and pressures on the system under a given set of supply and demand assumptions.

Determination of baseline capacity at entry points

The key objective in determining entry baseline capacity is to set capacity levels that adequately reflect the likely physical capability of the network at each individual entry point and for the network in aggregate, whilst taking into account changing gas flow patterns on the network. The following key points are considered in determining baselines:

- the base network (comprises of existing infrastructure, including planned investment);
- supply and demand assumptions (where various scenarios are considered);
- balancing the network (aggregate supplies entering onto the system must reasonably match aggregate demand being taken off the system);
- determining entry point capability (the maximum capacity that could be released at that entry point on a 1 day in 20 year peak day demand[33] given the base network infrastructure and without triggering the need for network reinforcement); and
- zonal and nodal interactions (in addition to local/nodal constraints, there may be additional regional or zonal constraints).

Determination of baseline capacity at exit points

Exit capacity baselines are determined using a "practical maximum physical capacity" methodology. The overriding principle behind this approach is that exit capacity baselines are calculated consistent with the maximum quantity of capacity available at each node, given a set of plausible scenarios for flows elsewhere on the network. The methodology for determining baseline is described below:

33 National Grid is required, through its Gas Transporter Licence, to plan the system to meet the 1 day in 20 year peak aggregate daily demand. This requirement is described under the '*Standard Special Condition A9 - Pipeline System Security Standards*'.

- the starting point is to establish a balanced demand and supply position based on 1 day in 20 year demand;
- the NTS must be able to simultaneously meet the combined baselines at each off-take without the need for exit investment or significant buyback of exit capacity;
- increases in demand, to determine the maximum exit capability at an exit point, are matched with increases in supply based on forecast assumptions of additional entry capacity; and
- modelling continues, by increasing exit flow, until investment is required for 'exit' purposes, at which point the amount of exit capacity is determined.

Source: National Grid, Excerpts from *Determination of the Technical Capacity of the National Transmission System*, March 2011.

4.2.2 Calculation of above baseline capacity

Any inefficiencies associated with the under-utilisation of capacity can be mitigated to some extent by including a mechanism that allows for the sale of additional, generally shorter term, capacity above the baseline.

Consistent with the approach to calculating baseline capacity, decisions as to what level of above baseline capacity should be made available to the market also require a trade-off between maximising utilisation of the network and minimising the risk of incurring congestion costs.

Similar software would be used to calculate the amount of additional capacity to be released (above the baseline) on a day-ahead basis, once there is more clarity and certainty on the factors that influence the amount of physically available capacity, including the nominations of firm capacity for the gas day.

The Commission recommends AEMO be responsible for such activity, because as system operator it would have the best knowledge of the expected pattern of flows and operational constraints on the network each gas day. The rules would provide the principles upon which AEMO would undertake this activity, and AEMO would be obliged to develop the necessary guidelines detailing the methodology.

4.2.3 Incentives to make capacity available

Under the contract-carriage regime, the contract between the pipeline operator and the shipper places obligations on both parties, so that they have legal and economic incentives to ensure that gas is delivered when required by the market. These incentives usually take the form of obligations and penalties.

The current Service Envelope Agreement (SEA) determines, among other things, the transportation capacity of the DTS and the obligations of the DTS service provider and the system operator in relation to the delivery of the agreed capacity.

In respect to each party's obligation, the SEA requires the DTS service provider to provide the system operator not only the agreed transmission system capacity, but also a range of supporting services. It further requires the system operator to observe good practice in operating the system and not operate facilities in a manner that would materially adversely affect the DTS service provider's ability to comply with its obligations under the SEA.

Under the proposed Southern Hub model, the Access Arrangement would be required to specify the baseline capacity,[34] and the DTS service provider’s obligation to make that capacity available and its liability for not making firm capacity available would remain part of the SEA. In other words, the obligations are important to ensure contractual liability for the delivery of the service; whereas the penalties give added reassurance not just that the firm baseline capacity would be available when needed, but also that there would be adequate repercussions and compensation for market participants if there are times in which demand is not met.

The Commission suggests the GMRG should also consider whether any other incentives (such as a formal incentive scheme in the Access Arrangement) are required – beyond the contractual obligations in the SEA – to encourage the DTS service provider to make baseline capacity available.

4.3 Capacity products

Under the proposed entry-exit system, market participants would be able to obtain:

- entry capacity at production, interconnection and storage entry points;
- exit capacity at direct connect transmission exit points, interconnection exit points and storage exit points; and
- counterflow capacity (i.e. capacity that enables gas to flow in the opposite direction to the predominant flow of gas) at interconnection points.

Exit capacity would also be available at distribution exit points, but as noted in section 4.4.1, market participants would not need to procure capacity at these points because the capacity would be dynamically allocated.

Baseline capacity at entry and exit points would be made available through sales of firm capacity, while above baseline capacity would be made available through sales of interruptible capacity.[35] Counterflow products, on the other hand, would be made

34 The Service Envelope Agreement (SEA) provisions in the NGL stipulate that the SEA must state the capacity of the DTS. It may be possible to do this by reference to the Access Agreement without needing to change the NGL provisions

35 Firm capacity would be sold from baseline capacity ahead of the gas day, because this would maximise the value of the capacity to both market participants (who would be able to use the firm rights to plan and manage risk) and the DTS service provider (who would have greater certainty about the recovery of its investment in the DTS). Interruptible capacity, on the other hand, would be sold from above baseline capacity and only made available on a day-ahead or within day basis once all the firm capacity is sold to enable as much capacity to be released and to maximise the utilisation of the system on those days. It may be possible to sell some of the above baseline capacity on a firm basis because on the day before the gas day the system operator would have a better understanding of the expected use of the DTS. This would, however, add a further layer of complexity to the market. Market participants would instead be able to judge for themselves

available on an interruptible basis, irrespective of whether it is sold from the baseline or above baseline capacity. Further detail on firm, interruptible and counterflow capacity is provided in Box 4.3.

Box 4.3 Firm, interruptible and counterflow capacity concepts

Firm capacity would entitle the holder of entry (exit) capacity to inject (withdraw) gas up to the maximum daily quantity (MDQ) and/or maximum hourly quantity (MHQ) specified in the contract on a 'firm' basis. This form of capacity right would be accorded the highest priority in terms of scheduling and would be the last service to be curtailed. If firm capacity cannot be provided then, subject to some limitations (e.g. force majeure events), the holders of these rights would be compensated.

Interruptible capacity, as its name suggests, would entitle the holder to inject (withdraw) gas up to the MDQ or MHQ, but the system operator would retain the right to interrupt the service. This form of capacity right would be accorded a lower priority than firm capacity in terms of scheduling and would be curtailed ahead of firm capacity.

Counterflow capacity would be equivalent to a backhaul service on a contract carriage pipeline and involves the 'virtual transportation' of gas in the opposite direction to the primary flow of gas. The term 'virtual transportation' is used in this context, because this service does not involve the physical transportation of gas, but instead results in transporting a lower net flow of gas in the primary direction.

For example, if some market participants were collectively withdrawing 1.5 TJ of gas from Culcairn on a gas day and other market participants collectively wished to inject 1 TJ of gas at Culcairn, then the market participants wishing to inject gas could purchase counterflow capacity to enable them to do so. The system operator would then net the flows of gas into and out of Culcairn, and only withdraw 0.5 TJ of gas from Culcairn.

Because counterflow involves 'virtual transportation', the amount of counterflow capacity which can be honoured can exceed the physical capacity of a system to transport gas in the counterflow direction, providing there is sufficient flow in the primary direction such that the net flows are within the physical capacity of the system. For example, an interconnection point which can inject 1 TJ but only withdraw 0.5 TJ would nevertheless be able to support up to 1 TJ of counterflow withdrawals, depending on the amount of gas physically injected.

As the volume of counterflow capacity must be lower than, or equal to, the volume of gas to be transported in the opposite direction, it can only be offered on an interruptible basis.

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whether capacity is likely to be interrupted through the publication of information on nominations on the Bulletin Board.

Given the potential for sales of above-baseline capacity by the system operator to adversely affect the DTS Service Provider's ability to recover its revenue requirement, interruptible products would only be offered on a day-ahead or within-day basis once all the firm baseline capacity has been sold. The one exception to this rule would be counterflow capacity, which would not be capable of being sold on a firm basis. Because the release of this form of interruptible capacity under longer-term contracts is unlikely to have any effect on the DTS Service Provider's recovery of revenue, this form of capacity would be available for all contract tenors.

Some examples of the form the firm and interruptible entry and exit rights could take is provided in Box 4.4, which provides an overview of the entry and exit products that have been developed in Europe.

Box 4.4 Entry and exit products in Great Britain and Europe

National Grid[36]

In Great Britain, the national transmission system (NTS) is operated on an entry-exit basis, with entry and exit capacity sold on both a firm and interruptible basis under standardised capacity products.

Entry capacity in the NTS is made available through a mix of:

- longer-term products, which include a firm quarterly product (available for up to 15 years in advance) and a firm monthly product (available for up to 18 months in advance); and
- shorter-term products, which include firm month-ahead, day-ahead and within-day products and an interruptible day-ahead product.

Exit capacity in the NTS is also made available through a mix of:

- longer-term products, which include firm enduring annual capacity products (available into perpetuity) and firm annual capacity (available for up to three years in advance); and
- shorter-term products, which include daily firm capacity and daily off-peak interruptible capacity.

Entry and exit capacity is sold on a kWh per day basis,[37] which provides for a flat flow rate over the gas day. The capacity products also include renomination rights.

36 Based on information on National Grid's website http://www2.nationalgrid.com/Britain/

37 According to the EU *Network Code on Capacity Allocation Mechanisms*, p. 12, "the capacity offered should be expressed in energy units per units of time, being kWh/h or kWh/d". In Australia the equivalent unit commonly used is GJ/h or GJ/day.

Cross border interconnection capacity products in Europe[38]

Cross border interconnection capacity in Europe is operated on an entry-exit basis, with entry and exit capacity sold on either a firm or interruptible basis under:

- longer-term standard capacity products, which include firm and interruptible annual products (available for up to 15 years in advance) and quarterly products (available for up to one year in advance); and
- shorter-term standard capacity products, which include firm and interruptible month-ahead, day-ahead and within-day products.

Interconnection capacity may either be expressed on a kWh per hour or kWh per day basis, with the latter option providing for a flat flow rate over the gas day.

Renomination rights are also available under some products.

In contrast to National Grid's system, interruptible capacity on cross border interconnection pipelines can be purchased for any tenor.

4.3.1 Standardised or bespoke products

One question that the change to the entry-exit system raises is whether bespoke or standardised entry, exit and counterflow products should be developed. While in principle these product dimensions could be tailored to meet the needs of individual market participants, bespoke products would be less fungible and therefore more difficult to trade. Given the adverse effects this could have on liquidity in the Southern Hub, the efficient utilisation of the DTS and the ability of parties to manage their transportation costs and risks, the Commission recommends that:

- standardised entry, exit and counterflow capacity products be developed, in consultation with market participants; and
- to the extent it is relevant, that the standardised products mirror the commodity products to be traded through the Southern Hub.[39]

In developing these standardised products, consideration would need to be given to standardising:

- the service related provisions, which include:

38 Based on information contained in EU Commission Regulation No. 984/2013.

39 For example, if a decision was made to develop a month-ahead, day-ahead, weekly and within-day commodity products for the Southern Hub then equivalent products should be developed for entry and exit capacity, along with some longer duration products.

- — the type of capacity right that is to be sold (i.e. entry, exit or counterflow capacity) and the priority (firm or interruptible) to be accorded to the capacity right in terms of scheduling and curtailment;
- — the entry, exit and counterflow points (or zones, if applicable) at which the capacity right relates;
- — the metric used to measure the amount of capacity the buyer can nominate for use on the gas day, which could be measured on a daily (MDQ) or hourly (MHQ) basis;
- — the renomination rights that would be available to the buyer;
- — the contract tenor (e.g. quarterly, monthly, weekly, daily and/or within-day); and

- the operational terms and conditions,[40] prudential provisions and other contract provisions that govern the relationship between parties (including any liabilities payable by the system operator if the firm service is curtailed).[41]

Consideration should also be given to whether it is feasible to aggregate any of the entry, exit or counterflow points into zones to facilitate capacity trading within the zone. If this is feasible, then consideration should also be given to whether it is technically possible to trade capacity across any of the zones and, if so, whether an 'exchange rate', similar to what AEMO currently calculates for AMDQ, would be required to convert capacity in one location to capacity at another location.

At this stage we would expect it to be possible to develop entry and exit zones around Iona and Longford. However, whether or not it would be feasible to develop zones around some of the direct connect exit points (e.g. on the Longford to Melbourne pipeline) to enable the direct connect transmission customers on this pipeline to trade capacity amongst themselves still needs to be determined.

Having market participants involved in determining the appropriate level of standardisation and how to achieve greater entry, exit and counterflow point flexibility is important because they would be the ones that would be using and trading the products. The Commission has nevertheless given some consideration to the form that the products could take and developed a number of required, preferred and suggested recommendations. These recommendations are summarised in Table 4.1, while Table 4.2 sets out what the entry, exit and counterflow products could look like if these recommendations were implemented.

40 Operational terms and conditions include: the start of gas day and nomination cut-off times, gas specification and quality; nomination, scheduling, curtailment and allocation procedures; and provisions relating to transfers, assignments and novations of capacity and capacity trading.

41 The other contract provisions include, for example, warranties, representations, possession and responsibility, title, control, liability and indemnities, default, termination, force majeure, notices, confidentiality and dispute resolution provisions.

Table 4.1 Recommended outcomes for the development of standardised products

Required	
Product type	Entry, exit and counterflow products should be developed.
Firmness of services	Firm and interruptible products should be developed, with firm capacity available for a range of contract tenors and interruptible entry and exit capacity available on a day-ahead and within-day basis only. Interruptible counterflow capacity should be available for all contract tenors.
Preferred	
Renomination rights	Renomination rights would ideally be included in the standardised product to enable market participants to manage intra-day changes. Limits on this right are, however, likely to be required to prevent market participants using this right to hoard capacity and limit its release through the auction for contracted but un-nominated capacity (see section 4.4.3).
Operational, prudential and other contract provisions	To the extent relevant, the operational, prudential and other contract provisions should be based on the standardised provisions that the GMRG has been accorded responsibility for developing for contract carriage pipelines.
Suggested	
Contract tenor	Given the seasonal nature of demand in Victoria and the types of products that are expected to be developed in the Southern Hub, there is likely to be value in developing the following products for firm entry and exit capacity and interruptible counterflow capacity: • longer-term products: quarterly products for up 10 or 15 years (i.e. 40-60 quarters) and monthly products for the next year (i.e. 12 months); and • shorter-term products: month-ahead, weekly, day-ahead and within-day products. The quarterly and monthly products would enable market participants to secure capacity on a longer-term basis, while the month-ahead, weekly, day-ahead and within-day products would enable market participants to manage their shorter-term capacity requirements. The different contract tenors would also enable market participants to tailor their capacity holdings through the year (e.g. by purchasing more capacity in winter), which would allow other market participants to purchase it at other times of the year.
Capacity metric	If there is sufficient demand for an hourly product, and if it feasible to do so given the wider market design, then capacity should be defined on an MHQ basis. Otherwise, it should be defined on an MDQ basis with either a flat hourly flow or a minimal amount of hourly flexibility (e.g. a 1.1 hourly load factor) and consideration given to whether additional hourly flexibility can be provided to those that require it (e.g. gas fired generators).

Table 4.2 Potential standardised products

Type of product	Entry	Exit	Counterflow
Firmness of service	Firm and interruptible		Interruptible
Points	Production, storage and interconnection entry points	Direct connect, storage and interconnection exit points. Exit capacity would also be available at distribution exit points but, as noted in section 4.4, market participants would not need to procure this capacity in advance	Interconnection points
Capacity metric	MDQ or MHQ		
Renomination rights	✓		
Contract tenor	Firm products: • quarterly (up to 10-15 years) • monthly (next year) • month-ahead • weekly • day-ahead • within-day Interruptible products: • day-ahead • within-day		Interruptible products: • quarterly (up to 10-15 years) • monthly (next year) • month-ahead • weekly • day-ahead • within-day

4.4 Capacity release and allocation mechanisms

Under the proposed entry-exit system entry, exit and counterflow products would be made available to the market on a transparent and non-discriminatory basis through the release of:

- existing baseline capacity, which would be made available at regular intervals under both short and longer-term timeframes; and

- above baseline capacity, which would be made available on a day-ahead or within-day basis once all the baseline capacity at a point has been sold, to enable as much capacity to be released to the market and to maximise the utilisation of the system.

Market participants would also be able to enter into secondary capacity trades with other parties that have spare capacity. They may further be able to secure capacity at contractually congested points through a day-ahead auction of contracted but un-nominated capacity.

Further detail on how these alternative forms of capacity would be released to the market is provided below.

4.4.1 Allocation of existing baseline capacity

Baseline entry and exit capacity would, as noted above, be made available on a firm basis under short and longer term contracts, while counterflow capacity would be made available on an interruptible basis.

If the demand for these products was always expected to be lower than the baseline capacity, then the capacity allocation task would be relatively straightforward. There would, however, be times when capacity is scarce and must be allocated between market participants. A mechanism is therefore required to enable baseline capacity to be released and allocated amongst market participants in times of scarcity through a transparent and non-discriminatory manner.

There are a range of mechanisms that can be used for this purpose including:

- auctioning capacity;
- allocating capacity in an unconstrained manner and then pro-rating capacity amongst market participants if a constraint arises (e.g. by scaling all requests for capacity down in proportion to the requested capacity);
- directly allocating capacity to market participants based on:
  - their historic usage or rights (grandfathering); or
  - on a first-come-first-served basis; and
  - dynamically allocating capacity to market participants based on end-use demand.

Further detail on these mechanisms and their respective strengths and weaknesses is provided in Box 4.5.

As the discussion in this box highlights, a well-designed auction mechanism, when coupled with anti-hoarding measures (see section 4.4.3), should result in the most efficient allocation of capacity at those points where participants can adjust their demand in response to price, because it uses price to allocate capacity to those that value it most highly.

An auction may not, however, be the most appropriate mechanism to use when market participants have limited ability to adjust their demand in response to wholesale price outcomes and where the nature of demand is such that it would not be appropriate to ration demand unless there was a significant curtailment event. An alternative mechanism is therefore required at these points.

In the DTS, the only points that substantially exhibit this characteristic are distribution exit points, with retailers at these points having limited real-time control over the use of gas by residential and small commercial customers.[42] Of the three remaining options, the dynamic allocation mechanism appears the most well suited to the task of allocating capacity at these points, because barring any significant force majeure event, it is unlikely that capacity at these points would need to be rationed if the capacity is built to meet, for example, a 1 day in 20 years planning standard. The use of the dynamic allocation mechanism would also prevent any hoarding of capacity at these points and allow all retailers (new and existing) to access capacity on the same basis.[43]

The Commission therefore recommends that baseline capacity be allocated through the following mechanisms:

- auctions at entry points, and interconnection, storage and direct connect (e.g. commercial and industrial customer sites and gas powered generation) exit points; and
- a dynamic allocation mechanism at distribution exit points.

The remainder of this section provides an overview of these two capacity release and allocation mechanisms, the role the AER would play in approving the prices of the capacity released through these mechanisms and how AMDQ and AMDQ cc could be transitioned to the new system of entry-exit rights.

Box 4.5 Capacity allocation mechanisms

Auction

An auction mechanism uses price to allocate capacity to those that value it most highly and therefore requires parties to be able to adjust their demand in response to price. A well-designed auction mechanism would promote competition between bidders and those who place a relatively high value on the capacity being auctioned would generally be willing to bid highest for it. Capacity would therefore be allocated efficiently, if value is correlated to bids.

42 Retailers could influence demand by using time of use tariffs or demand response mechanisms. However, demand response mechanisms are currently rare for residential and small gas customers, and time of use tariffs do not dynamically reflect spot market prices for gas.

43 A dynamic allocation process is not possible at all points in the DTS, because it is not possible to offer everyone all the capacity they want if there are constraints in the system.

Specific market conditions and design issues can, however, distort auction outcomes and affect the efficient allocation. For example, if a small number of smaller market participants and one large participant were seeking capacity at an exit point, there could be a risk that the larger participant may be able to exploit its dominant position to block the smaller participants from accessing the baseline capacity. In these circumstances, anti-hoarding mechanisms are likely to be required (see section 4.4.3).

Unconstrained capacity release and use of a pro-rata mechanism

An alternative to an auction is to allow all market participants to be allocated capacity at a set price and to use a pro-rata mechanism to allocate capacity in periods of scarcity (e.g. scaling all capacity requests down in proportion to the volume of requested capacity). In effect, this mechanism guarantees all parties can access a minimum amount of capacity, which may be of some benefit if there is a risk some participants may use auctions to block smaller parties from accessing capacity.

While the pro-rata mechanism is a relatively simple mechanism, it is unlikely to result in capacity being allocated to those that value it most highly because it does not use price to allocate capacity. The application of such a mechanism may also encourage parties to over-book capacity so they can guarantee access to the required level of capacity in periods of scarcity. There is also a risk that a market participant’s capacity would be reduced to such a level it is of little commercial value.

Grandfathering and first-come-first-served mechanisms

Grandfathering capacity involves allocating capacity on the basis of historic usage or rights, while the first-come-first-served mechanism allocates capacity in the order it is requested. Like the pro-rata mechanism, these mechanisms are relatively simple to implement, but would not necessarily result in an efficient allocation of capacity because they do not use price to allocate capacity. These mechanisms may also enable incumbents to hoard capacity, which would act as a barrier to entry for new parties.

Dynamic allocation linked to end-use customers

Where market participants do not have any direct control over their gas use, capacity may be allocated in an automated and dynamic manner. This is often the case for retailers who cannot control how much gas their end-use customers use. In these circumstances capacity may be automatically allocated at exit points to the distribution network to retailers based on their downstream market share.

While a dynamic allocation mechanism does not use price to allocate capacity between parties, it may still result in capacity being allocated to those that value it most highly through the process of retail competition.

Auction of capacity at entry points and non-distribution exit points

Market participants wanting to obtain entry capacity, counterflow capacity and/or exit capacity at interconnection, storage and direct connect points would, under the proposed model, be required to purchase the capacity through an auction(s). There are a number of different formats that the auction could take, with the choice between these depending on, amongst other things:

- the nature of the products to be auctioned and the demand for these products;
- the number of bidders and the extent of competition between bidders; and
- the objectives of the auction.

Some of the more common formats that could be used are set out in the table below, while Box 4.6 provides an overview of the auction formats used in Europe.

Table 4.3 Auction formats

Auction formats		Description
Auction format	Sealed bid auction	In a sealed bid auction, all bidders submit sealed bids at the same time.
	Ascending price	Under an ascending price auction, the price is progressively raised over multiple rounds until the first price increment is reached where demand falls to the level that matches supply.
	Descending price	Under a descending price auction, the price is progressively lowered over multiple rounds until the first price decrement is reached where demand falls to the level that matches supply.
	Clock auction (ascending or descending price)	Under this type of auction the ‘clock price’ ticks up (or down) by pre-defined amounts over multiple rounds until demand is less than or equal to supply. Winning bidders pay the same uniform price established in the final round.
	Combinatorial or conditional auction	Combinatorial and/or conditional auctions allow bidders to place bids on combinations of products. An optimisation algorithm is then used to identify the highest value combination of bids. A number of variants of multiple-round auctions with combinatorial bidding exist, including the combinatorial clock auction.
Pricing rules	First price (pay your bid)	Winning bidders pay the amount they bid, so the unit price varies across users.
	Second price	Winning bidders pay the minimum amount they would have needed to bid in order to win the auction.
	Uniform price	All winning bidders pay the price of the lowest successful bid (or in some cases the highest losing bid).

Box 4.6 Auction designs in Europe

National Grid

Entry capacity and short-term exit capacity in the NTS is currently sold by National Grid through periodic auctions conducted throughout the year (see table below).[44]

<table>
<tr><th>Product</th><th>Frequency</th><th>Auction Design</th><th>Reserve Price</th><th>Capacity Available</th></tr>
<tr><td colspan="5">Entry Products</td></tr>
<tr><td>Quarterly (up to 15 years)</td><td>Annual</td><td>Integrated multiple rounds, uniform price.</td><td rowspan="3">Long run marginal cost</td><td>Unsold capacity (up to 90% of baseline) plus incremental capacity</td></tr>
<tr><td>Annual Monthly (up to 18 months)</td><td>Annual</td><td>Sequential sealed bid first price 4 x 25% tranches sold sequentially</td><td>10% baseline + unsold quarterly entry capacity</td></tr>
<tr><td>Month ahead</td><td>Month ahead</td><td rowspan="4">Single round sealed bid first price[45]</td><td rowspan="4">Unsold capacity from prior auctions + surrendered capacity</td></tr>
<tr><td>Day-ahead</td><td>Day ahead</td><td>33.3% discount to quarterly product</td></tr>
<tr><td>Within-day</td><td>Hourly on the gas day</td><td rowspan="2">Zero</td></tr>
<tr><td>Daily interruptible</td><td>Day ahead</td></tr>
<tr><td colspan="5">Exit Products</td></tr>
<tr><td>Day-ahead off-peak[46]</td><td>Day ahead</td><td rowspan="2">Single round sealed bid first price</td><td>Zero</td><td>Capacity surrendered through use it or lose it scheme, unutilised maximum network exit point off-take rate and discretionary release</td></tr>
<tr><td>Within-day</td><td>Hourly on the gas day</td><td>Annual price for firm products</td><td>Unsold exit capacity.</td></tr>
</table>

44 National Grid, *Statement of Gas Transmission Transportation Charges*, April 2016.

45 In the sealed bid auctions, capacity is allocated in descending price order until it is all allocated.

46 Off-peak capacity is made available by National Grid where it can be demonstrated that there is firm capacity not being utilised. National Grid can curtail off-peak capacity without having to pay compensation.

The key points to note from this table are that:

- three different auction formats are used to release entry and exit capacity;
- 10 per cent of baseline capacity must be reserved for shorter-term auctions; and
- the reserve prices for shorter-term products are currently set at a discount to long-term products, although Ofgem has expressed some concerns about this given the excess capacity in the NTS and has recommended National Grid work with industry to reduce the discounts.[47]

It is also worth noting in this context that because National Grid is subject to a revenue cap any over-recoveries of revenue generated through the auctions must be returned to users through the buy-back mechanism or a commodity charge rebate, while under recoveries must be recovered through a commodity charge.

Cross border interconnection capacity in Europe

EU Commission Regulation No. 984/2013 requires cross border interconnection point capacity to be allocated in the manner set out in the table below.

<table>
<tr><th>Product</th><th>Frequency</th><th>Auction Design</th><th>Capacity Made Available</th></tr>
<tr><td>Yearly (up to 15 years)</td><td>Annual</td><td rowspan="3">Ascending clock (uniform price)</td><td>Unsold capacity (up to 80% of baseline) plus incremental capacity</td></tr>
<tr><td>Quarterly (up to 1 year)</td><td>Annual</td><td>10% baseline + unsold quarterly entry capacity</td></tr>
<tr><td>Month ahead</td><td>Monthly</td><td rowspan="3">Unsold capacity from earlier auctions</td></tr>
<tr><td>Day ahead</td><td>Daily</td><td rowspan="2">Single round sealed bid (uniform price)</td></tr>
<tr><td>Within day</td><td>Hourly</td></tr>
</table>

As this table highlights, the EU Regulation requires interconnection capacity to be auctioned using:

- An ascending clock uniform price auction for yearly, quarterly and monthly products.[48] Under this auction format, bidders are required to

47 Ofgem, *Gas Transmission Charging Review: our policy position on future entry charging arrangements*, 12 December 2014.

48 The decision to employ the ascending clock uniform price auction in the EU was informed by advice from Frontier Economics, who noted that the main benefit of the ascending clock auction is that bidders receive feedback at the end of each round on the level of aggregate demand, which facilitates price discovery and improves the efficiency with which capacity is allocated. Frontier also noted that the uniform price rule can encourage efficient allocation and facilitate participation

place volume bids against escalating price steps in consecutive bidding rounds until demand is less than or equal to capacity. The starting price in the auction is the reserve price, P0.

- If demand exceeds capacity offered, then the price in the next round would increase by a large price step and would continue to increase by this amount in subsequent rounds until demand falls below the capacity on offer.
- Once demand falls below this level, the last price step is unwound and the price increased by small price steps until demand is less than or equal to capacity.

- A single round sealed bid uniform price auction for other shorter term products.

The other point to note from this table is that the EU Regulation requires 20 per cent of the baseline capacity at each point to be set aside, of which:

- 10 per cent is reserved for short-term sales (i.e. products for the next year) to mitigate the risk of congestion and provide some flexibility; and
- 10 per cent is reserved for annual yearly auctions conducted from the fifth year to mitigate the risk that 80 per cent of the capacity would be sold for 15 years.

The regulation also provides for National Regulatory Authorities to determine:

- auction reserve prices and any applicable multipliers or discounts for contracts with different tenors; and
- how any over or under recovery from the auction would be treated (e.g. returned to market participants in the form of lower tariffs, or to carry out works to reduce congestion).

As Box 4.6 highlights, there are some marked differences between the auction formats used by National Grid and those used for interconnection capacity in Europe (i.e. sealed bid single round, pay as bid auctions and integrated auctions or ascending clock uniform price auctions and sealed bid single round, uniform price auctions). There are, however, also some points in common, with both methodologies:

- using less sophisticated auction formats for shorter-term products (e.g. day-ahead and within day) to enable the auction to be concluded more rapidly;
- reserving a fixed proportion of baseline capacity for shorter-term auctions, to ensure that market participants have some flexibility to manage their portfolios in the short-term and to enable new entrants to access capacity; and
- using the regulated tariffs as the auction reserve price.

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by less experienced market participants. See Frontier Economics, *Auction design for capacity allocation in gas transmission networks*, March 2012, p. 41.

Turning now to the question of what auction format(s) should be used in the DTS. As noted previously, the choice between the various auction formats would depend on:

- **The nature of the product(s) to be auctioned** – If standardised entry, exit and counterflow products are developed, then the products to be auctioned would be relatively homogenous (see section 4.3).
- **The nature of demand** – Market participants in the DWGM currently consist of a mix of small and large commercial and industrial customers, retailers, LNG proponents and gas powered generators. The demand for capacity by these market participants is expected to be relatively heterogeneous, with individual capacity requirements, the ability to adjust demand and the value attributed to capacity varying across market participants. It may also be conditional in some cases on obtaining access to capacity at another entry or exit point (e.g. for those market participants just wanting to transport gas out of Victoria).
- **The number of bidders and the extent of competition between bidders** - Based on current injection/withdrawal patterns there could be a reasonable number of bidders at the main entry and exit points, but few bidders at direct connect exit points and some entry and interconnection points.
- **The objectives of the auction –** In this case the objectives would be to:
  - allocate capacity in an efficient, transparent and non-discriminatory manner;
  - promote the efficient use of the DTS and provide clear investment signals;
  - provide the DTS service provider with a reasonable opportunity to recover at least the efficient cost of providing services by setting the reserve price(s) equal to the reference tariffs, which must be approved by the AER;
  - allow market participants to manage their portfolios over time and newer entrants to obtain capacity; and
  - particularly in the case of shorter-term products be simple, low cost and quick to conduct.

Given these observations and objectives, the Commission would suggest that:

- the auction of longer-term products (e.g. quarterly and monthly products) take the form of an ascending clock uniform price auction, if it is feasible to do so, or if this is not possible a sealed bid uniform price auction;
- the auction of shorter-term products (e.g. month ahead, day ahead or within day products) take the form of a single round sealed bid uniform price auction; and
- a fixed proportion of the baseline capacity be reserved for shorter-term auctions (e.g. monthly, month ahead, day ahead or within day products).

The Commission also recommends that the AER, performing its economic regulatory functions, be accorded responsibility for:

- approving the reserve prices to be used in the auctions; and
- determining how any over or under recovery of revenue or prices be treated.

The auction design related recommendations are only suggestions at this stage because before a final decision is made on this issue, market participants would need to be consulted and the feasibility of particular auction designs would need to be assessed. The Commission therefore recommends that the GMRG be accorded responsibility for taking this forward and, as part of its assessment process, consider:

- the feasibility of using an ascending clock auction for longer-term products and whether there is likely to be sufficient demand to adopt a combinatorial ascending clock auction (i.e. to accommodate market participants whose demand is conditional on getting access at multiple points);
- whether the uniform pricing rule is the most appropriate rule to employ;
- the frequency with which the auctions should be conducted, particularly given the concerns some stakeholders have raised about the need to align gas supply contracts with gas transportation arrangements;
- whether some restrictions on who can hold capacity at direct connect exit points are required to prevent third-parties from trying to acquire this capacity in an auction for strategic purposes (e.g. to prevent users at these sites accessing capacity or restricting their choice of retailers);[49] and
- the proportion of baseline capacity that should be reserved for shorter-term auctions.

As part of this process, there would also be value in considering whether capacity at direct connect exit points should, as an interim step, be directly allocated to users at these points for a defined period of time before transitioning to the auction process. While the Commission's preference is for capacity at these locations to be auctioned, it understands that users at these sites may require some time to adjust to the changes given the scale of the proposed changes. There would be value therefore in considering whether the auction process should be introduced incrementally, with auctions of entry, interconnection and storage exit points to occur when the market commences and direct exit points at a later point.

Finally, it is worth noting that some questions have been raised about the value of auctioning capacity at direct connect sites[50] if there is only one party bidding at a site.

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49 While this concern may be addressed to some extent by the auction of contracted but un-nominated capacity, some large industrial customers may be unable to rely on this type of capacity.

50 See for example, AEMO, Submission to March Discussion Paper, 1 April 2016, p. 6 and APA, Submission to March Discussion Paper, March 2016, p. 14.

It is firstly worth noting that there would be more than one party bidding if exit points are aggregated into zones as suggested in section 4.3.1.[51] In any event, the auction process would provide a mechanism for the booking of capacity at the reference tariff (in the absence of competition). The Commission is therefore of the view that barring any transitional period, capacity at these sites should be auctioned in the same manner as other exit capacity is auctioned.

Dynamic allocation of capacity at distribution exit points

In contrast to the other entry and exit points in the DTS, market participants at distribution exit points would not be required to pre-purchase exit capacity. This capacity would instead be allocated on a dynamic basis by AEMO to individual market participants based on the volume of gas their customers consumed. This is akin to how AMDQ for Tariff V customers (all residential and small-to-medium sized commercial and industrial customers) is currently allocated in the DTS and is appropriate given the nature of demand at these points.[52]

From a retail competition perspective, the use of this type of allocation mechanism would enable all retailers (new entrants and incumbents) to access the distribution exit points. It also means that new entrant retailers would not have to commit to purchasing exit capacity when demand is uncertain and would prevent more established retailers from hoarding capacity at the distribution exit points.

In a similar manner to the current arrangements, the AER would be responsible for approving the reference tariffs for these products.

The form that these charges could take is considered further below.

Pricing of baseline capacity and form of regulation

The price at which baseline capacity is sold under the entry-exit system would, as noted above, be subject to regulatory oversight, with the AER retaining responsibility for approving the reference tariffs for entry, exit and counterflow capacity products (which would act as the reserve price for auctions) on an *ex ante* basis.

In determining the reference tariffs for entry, exit and counterflow products, the AER would need to consider a range of issues, including:

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51 It should further be noted that above-baseline capacity might be auctioned across wider zones than baseline capacity (i.e. to be meaningful, it may be necessary to define baseline capacity on a relatively granular locational basis, whereas it may be possible to auction any available above-baseline capacity on a wider, potentially even system-wide, basis).

52 The rationale for allocating the original AMDQ to customers rather than market participants, retailers or shippers was to not create a barrier to retail competition. For example, if AMDQ were held by retailers, there was a concern that those retailers who won customers from rival retail businesses would then be forced into a position of either trying to negotiate with that rival retailer to sell them AMDQ, or take on additional risk.

- how the costs of providing services in the DTS should be divided between entry and exit capacity;[53]
- whether unique tariffs should be developed for each entry and exit point, or if tariff zones should be developed, which would align with any zones that are used to aggregate entry or exit points (see section 4.3);
- the tariff structure to be used for firm entry and exit products and interruptible counterflow products (i.e. a capacity charge, a throughput charge or a combination of the two), which could differ across the products;[54]
- how the price of shorter-term products should be set relative to the price of longer-term products;
- whether any seasonal factors should be applied to the tariffs to reflect the difference in the cost of using the DTS at different times of the year;[55]
- how the price of counterflow products should be set relative to the price of firm entry and exit products at the same location; and
- whether a different tariff structure should be employed for gas fired generators, which are increasingly being used in a peaking capacity and may not be in a position to pay a fixed capacity charge all year round, but may be able to pay a higher charge when they are run (see Box 4.7).

To enable the AER to consider some of these issues, amendments may need to be made to the provisions in Part 9 of the NGR dealing with reference tariffs. Currently the NGR only requires reference tariffs for transmission services to reflect the cost reflectivity principles in rule 95 of the NGR. While some of these issues could feasibly be captured by the cost reflectivity principles, others may not. Further guidance may therefore be required in the rules.

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53 The AER is required to consider a similar issue under the market carriage model, with costs allocated between injection and withdrawal tariffs.

54 For example, it may be appropriate to adopt a throughput charge for the interruptible counterflow product so that market participants only pay for this service when it is provided, which is equivalent to how interruptible and as available services are treated on contract carriage pipelines. A similar tariff structure may also be appropriate for distribution exit points given that market participants would not have a fixed allocation of capacity at these points, rather their capacity would be allocated dynamically based on end-customer usage.

55 National Grid's shorter-term products have historically been sold at a discount to the longer-term products. We understand, however, that steps are now being taken to reduce these discounts because excess capacity in the NTS has meant that market participants have placed greater reliance on the cheaper short-term products, which has meant it has been increasingly difficult for National Grid to recover its revenue requirement. In Europe, on the other hand, draft pricing principles developed by ACER for transmission pipelines suggest that products with a shorter duration than one year should be proportionate to the yearly tariff on average over the gas year.

Box 4.7 Pricing flexibility for gas fired generators

In Europe gas fired generation is increasingly being used to provide back-up for renewable generation and in a peaking capacity. To accommodate this change in the operating environment, the European electricity industry association (Eurelectric) published a report in April 2016, which advocated greater flexibility in exit capacity products and pricing.[56] Some of the measures Eurelectric suggested include:[57]

- requiring pipeline operators to offer annual, monthly, daily and within-day exit products and making within-day capacity available in each hour of the gas day;
- offering gas fired generators the option of moving away from a capacity based tariff structure for exit capacity to more of a usage based tariff; and
- offering lower priced annual exit products to gas fired generators for pre-defined utilisation rates and if actual utilisation rates exceed these levels, apply a pre-defined surcharge or requiring capacity to booked at a more expensive short-term rate.

One pipeline operator in Europe that has responded to the change is Fluxys in Belgium, which has recently introduced a two-part tariff structure (fix/flex rate) for gas fired generators and industrial customers. Under this tariff structure, gas fired generators are required to pay a fixed capacity charge ('Fix') for the booked capacity, which covers the generator's peak requirements and a usage charge ('Flex') for the actual running hours.[58]

A more fundamental question that still needs to be considered is whether the price payable for capacity purchased through an auction[59]under longer-term contracts[60] should be:

- fixed at the time the capacity is purchased and locked in for the duration of the contract (subject to the operation of a price escalation mechanism); or
- based on the reference tariff (plus any premium above the reference tariff that may be paid through the auction), which could change over the life of longer-term contracts ('floating tariff').

56 Eurelectric, *Gas flexible exit capacity products*, April 2016.

57 ibid, p. 3.

58 Fluxys, *Transmission Programme*, 19 May 2016.

59 This is not relevant to distribution exit points because market participants would not be contracting for capacity. The price at these points would therefore be expected to be based on the reference tariff in place at the time the gas is transported with all market participants paying the same price.

60 This is not relevant to shorter-term products because the reference tariff is unlikely to change over the term of that product.

The first of these approaches is akin to what occurs on contract carriage pipelines, while the second approach is more akin to what currently occurs in the DTS. National Grid currently uses fixed tariffs, although the floating tariff approach was recommended by Ofgem in late 2014 following a review of National Grid's entry charging arrangements,[61]and is also used widely through Europe.[62]

There are pros and cons associated with both of these options. For example, fixing the price for the duration of the contract would provide market participants with greater certainty about what their commitments are over the life of the contract. This option could, however, result in significant variation between the prices payable by market participants depending on when they enter into contracts. If a large proportion of the pipeline's capacity was sold under long-term contracts and costs were expected to increase in the future, this option could also affect the DTS service provider's ability to recover the efficient cost of providing the service and/or result in higher tariffs for market participants that purchase capacity at this time. On contract carriage pipelines this risk can be managed to some extent by the pipeline operator limiting the term over which the capacity is sold. This would not, however, be an option under the entry-exit system, which is why the floating tariff option may be more appropriate.

The main downside of the floating tariff is that market participants would not necessarily know what they are committing to when they bid for longer-term capacity products. This may be less of a concern to market participants if they know the reference tariffs would be subject to regulatory oversight by the AER.

Given the pros and cons associated with these two options, the Commission is interested in hearing further from stakeholders on this issue before it publishes its final report.

On a separate, but related issue, the Commission has given some consideration to whether the movement to the entry-exit system and the use of auctions would necessitate a movement to a revenue cap form of regulation for the DTS. While this form of regulatory control is used in a number of countries in Europe, there are a number of other countries in Europe that use a price cap form of control.[63] There does not therefore appear to be a need to mandate the use of a revenue cap form of regulation. The decision as to what form of regulatory control should be applied to the DTS would instead be left to the AER and determined in the same way it currently is through the Access Arrangement review process.[64]

Rule 97 of the NGR provides the AER with flexibility in relation to the form of regulatory control. It would be open therefore to the AER to decide that during the

61 Ofgem, *Gas Transmission Charging Review: our policy position on future entry charging arrangements*, 12 December 2014,

62 ACER, *Opinion of the Agency for the Cooperation of Energy Regulators No 02/2015 on the Network Code on Harmonised Transmission Tariff Structures for Gas*, 26 March 2015, p. 9.

63 For example, a revenue cap form of regulation is used in France, Germany and the Netherlands, while a price cap is used in Slovakia and Slovenia. See DNV KEMA, Energy & Sustainability, *Country factsheets - Entry-Exit regimes in gas*, July 2013.

64 This decision is required to be made under rule 97 of the NGR.

transition from the market carriage model to the entry-exit system, a revenue cap form of regulation should be applied if there is some uncertainty surrounding demand.

It is worth noting in this context that the choice between the revenue cap, price cap or hybrid price-revenue cap[65] would have implications for the way in which any under or over recoveries of revenue or prices are treated. For example:

- If the revenue cap form of regulation is used and the auction results in the DTS service provider recovering more than its revenue requirement, this would be returned to market participants in the form of lower reference tariffs.
- If the price cap form of regulation is used, then:
  - the DTS service provider would be able to retain any additional revenue arising as a result of outturn demand for capacity rights differing from forecast demand (i.e. because under a price cap form of regulation the DTS service provider bears demand risk); and
  - if the price received through the auction is greater than the reference tariff, the additional revenue derived from this price differential could either:[66]
    - be returned to market participants in the form of lower reference tariffs; or
    - be used to offset AEMO's congestion management costs and market participation fees, which would also benefit market participants.

Transitioning AMDQ and AMDQ cc

Under the current DWGM, market participants may hold Authorised Maximum Daily Quantity (AMDQ) and AMDQ credit certificates (AMDQ cc).[67]These instruments provide their holders with:

- financial and physical rights, which provides holders with higher priority in the scheduling process if there is a tie in injection bids and also provides some protection against congestion uplift, but not other uplift charges, such as common or surprise uplift; and

65 A hybrid price-revenue cap contains elements of both price and revenue cap mechanisms. The precise combination of elements can vary, but it usually involves the use of a price cap (or average revenue cap) that can be adjusted for any under or over recovery of revenue above a certain threshold due to demand variations. The DTS is currently operating under a hybrid price-revenue cap, with the revenue cap element protecting APA from weather related demand risks.

66 The first of these options would be available to the AER under the current regulatory framework, but if the second option was to be employed, then changes to the NGR may be required.

67 AMDQ is a right created by the NGR, while AMDQ cc is a contractual right. Tariff D AMDQ is held by the end-user, while Tariff V AMDQ and AMDQ cc is held by the market participant responsible for transporting the gas.

- limited curtailment protection rights, which provides holders with some protection against curtailment in the event of an emergency with AMDQ holders having higher priority than customers with no AMDQ.

The movement to the Southern Hub trading model and the entry-exit system would alter (or remove) most of the risks that AMDQ and AMDQ cc currently allow market participants to manage. In many ways, these instruments would be replaced by entry and exit rights, which would offer superior access to transmission capacity. It would not be necessary or even feasible to retain AMDQ and AMDQ cc alongside entry and exit rights. This consequently raises the issue of the treatment of AMDQ and AMDQ cc rights previously allocated to market participants for periods following the commencement of the new arrangements.

In short, the Commission's preference is for AMDQ to be treated in the following manner:

- **Distribution exit points – Tariff V AMDQ**, which is dynamically allocated to retailers based on customer numbers, would essentially be replaced by the dynamic allocation of firm capacity at distribution exit points. **Tariff D AMDQ** at distribution exit points would also be replaced by the dynamic allocation process;

- **Non-distribution exit points – Tariff D AMDQ** holders at these points would, as a transitional measure only, be given the option to acquire firm capacity rights up to their current AMDQ holding for as far into the future as capacity is made available. This capacity would be directly allocated to AMDQ holders at the reference tariff, which means that they would not have to compete at the auction for capacity.[68] For Tariff D AMDQ holders that are supplied by a retailer, the new arrangements would allow the firm rights to be assigned to the retailer for the duration of their retail contract. At such time as the option was allowed to lapse, however, the holder would have no further priority rights.

As to **AMDQ cc**, the Commission understands that the need to transition rights is likely to be less of an issue because these are time limited products. To the extent there are any AMDQ cc on foot when the transition occurs, the Commission would suggest employing a similar approach to that proposed for Tariff D AMDQ holders, with the exception being that AMDQ cc holders would only be able to acquire the right for the remaining term of their AMDQ cc.

To give effect to these transitional arrangements, changes would need to be made to the NGR and possibly to the NGL.

68 It is worth noting in this context that AMDQ and AMDQ cc holders currently pay the reference tariff to access transportation capacity on the DTS.

4.4.2 Above baseline capacity

In order to promote the efficient utilisation of the DTS, the entry-exit system would include a mechanism to allow for the release of additional, shorter term capacity above the baseline level.

The Commission recommends that AEMO be accorded responsibility for the release of this capacity and that it be released through a day-ahead and/or within day auction on an interruptible basis. AEMO is best placed to achieve an efficient allocation of above baseline capacity, as it is also the party responsible for system operation and congestion management. However, the ability to use financial incentives to encourage efficient decisions would be limited by AEMO's status as a not-for-profit entity. The revenues AEMO receives from the sale of above baseline capacity could be used to offset any otherwise unallocated congestion management costs and/or could offset participant fees.

Importantly, this capacity would only be available at entry and exit points where baseline capacity has been sold, so it does not undermine the DTS service provider's ability to recover revenue from the sale of baseline capacity.

In the event the sale of above baseline capacity leads to constraints on the day (that is, more capacity being nominated for use by market participants than can be delivered), the interruptible nature of the above baseline capacity would provide AEMO with the ability to curtail those rights in order to manage the congestion.

In a similar manner to the auction of short-term baseline capacity products, the Commission suggests that the sale of day-ahead or within-day above baseline capacity be auctioned using a single round sealed bid auction with a zero reserve price.

4.4.3 Measures to encourage the release of secondary capacity

Market participants would be able to trade capacity on a secondary basis with without the need for any form of approval from the DTS service provider or the system operator. However, with the allocation of baseline capacity occurring well in advance of the gas day, there is a risk that market participants might not trade unused or unwanted capacity to others who might be able to use it and value it more, which would affect the efficiency with which the DTS is used. This may happen simply because there are insufficient incentives available to the holder to make the capacity available, although there could be a risk of deliberate hoarding.

The Commission therefore recommends two measures to encourage the release of secondary capacity:

- a short-term use-it-or-lose-it (UIOLI) mechanism for contracted but un-nominated baseline capacity at points with contractual congestion, which would be released to the market through a day-ahead auction after the nomination cut-off time; and

- the development of an electronic exchange that would enable market participants to trade secondary capacity on an anonymous basis.

Auction for contracted but un-nominated capacity

The Commission recommends that a day-ahead auction for contracted but un-nominated baseline capacity be used at points where there is contractual congestion (because all baseline capacity has been sold), with the auction to occur shortly after the nomination cut-off time. The aim of this mechanism is to provide an opportunity for market participants to access contracted but un-nominated capacity on a competitively priced basis.

Furthermore, the presence of the auction may result in more capacity being traded prior to the nomination cut-off time into the possession of the market participant which values it the most. This is because of the improved incentives for market participants to sell capacity and the measures to reduce transaction costs and facilitate frictionless secondary capacity sales between market participants (described further on "Secondary capacity trading" later in this section).

In addition, the Commission's preference is for capacity sold through this auction to be sold in firm and interruptible components, with the interruptible component only released when the entire firm component is sold. The original owner of the firm capacity would not be compensated (otherwise there is no real incentive for market participants to trade before nomination cut-off time) but would retain the right to increase existing nominations by an amount up to the interruptible component.[69] In setting the firm and interruptible components, the market design must:

- discourage owners over-nominating to hoard capacity;
- allow the original owner to access some of the capacity as a renomination increase right; and
- minimise disruption to purchasers of the interruptible component.

The Commission recommends that the reserve price for this type of auction to be set at zero, with the successful bidders either providing or paying for compressor fuel in a manner consistent with all other flows. This is consistent with the recommendations made in the East Coast Review stage 2 final report. The rationale is that it is best to set the reserve price at the short-run marginal cost (SRMC) because this is the cost at which using the capacity is of greater value than not using it. NERA's report[70] explains that in this case, the SRMC closely approximates to the cost of incremental gas

69 We recognise that demand for gas in the DTS is usually a function of the weather, which means demand can vary significantly within the gas day, and that some level of flexibility is also required in order to allow market participants to bid into the National Electricity Market. In the current market design market participants have a certain degree of flexibility in renomination through the five bidding windows available in the gas day

70 See NERA Economic Consulting, *Determining a reserve price for a short term gas transmission auction*, February 2016.

used to run compressors, with no other components materially contribute to the SRMC.

Finally, the Commission's preferred outcome is for the auction to take the form of a single round sealed bid auction. Consistent with the recommendation from the east coast review, proceeds from the auction would not be returned to capacity holders. Instead, the Commission's preferred outcome is for the auction revenue to be retained by the system operator and used to offset any otherwise unallocated congestion management costs and/or could offset participant fees.

Secondary capacity trading

The Commission recommended in the East Coast Review stage 2 final report the mandatory development of a capacity trading platform that would allow market participants to anonymously post buy or sell offers for secondary capacity. This would give existing market participants the opportunity to recover costs for contracted but unutilised capacity or obtain additional capacity, and also provide new and smaller organisations with the opportunity to purchase firm capacity on fully contracted assets for set periods of time, allowing capacity to be allocated to parties that value it most.

To facilitate an effective secondary market for all products, the Commission recommends that a harmonised platform and system be developed to allow capacity transfers to be made quickly and with immediate effect.

Despite wanting to encourage as much trade as possible to occur through the capacity trading platform to enhance liquidity, the Commission recognises that there may still be a role for bilateral trades outside the platform, and that forcing all trades to occur through the platform may discourage some participants from trading. The Commission's preference is for any trades conducted outside the capacity trading platform to be advertised ahead of time on the capacity trading platform listing service so that other market participants have an opportunity to compete for this trade.

Box 4.8 Secondary trading procedures available in Europe

In Europe the platform used for the sale of primary capacity rights of interconnection points, PRISMA, has since early 2014 started to be used to offer secondary capacity trading. Through PRISMA a market participant can use the platform in three different ways:

1. A market participant can either request or offer secondary capacity through an open call-for-order (CFO), which any market participant registered on the platform can respond to. The initiator of the CFO can then freely decide which counterparty he chooses to do business with; or

2. A market participant can enter a first-come-first-served (FCFS) entry on the platform, offering or requesting capacity at a fixed price; or

3. Two market participants can agree on a deal over-the-counter (OTC) and then register the transaction on the platform. In contrast to the anonymous CFO and FCFS mechanisms, the two parties of an OTC deal are already

known to each other and negotiate the price and the conditions of the trade offline.

Use of operational transfers in secondary trades and the day-ahead auction of contracted but un-nominated capacity

The Commission recommends that trades executed through the capacity trading platform and the auction should be given effect through an operational transfer:

- From a buyer's perspective, the operational transfer would provide anonymity in terms of nominations and its use of the pipeline, which is likely to be of some importance if the buyer has purchased capacity from a competitor;

- From a primary capacity holder's perspective, the operational transfer would alleviate it of the costs that it would otherwise incur in administering the trade and monitoring the buyer's compliance with various obligations, which should encourage more primary capacity holders to sell any spare capacity they have.

Under an operational transfer, the buyer would make nominations directly to the system operator and compliance with operational and other contractual obligations would be a matter for the buyer and system operator. The administrative and monitoring costs should therefore be low for the primary capacity holder under this type of trade.

Information on secondary capacity trading and day-ahead auction of contracted but un-nominated capacity

The Commission recommends the publication of information on all secondary trades of pipeline capacity and the results of the day-ahead auction of contracted but un-nominated capacity. The information to be published would be the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties, and should occur at or shortly after the time the transaction is entered into.[71] This would provide greater transparency by:

- aiding the price discovery process for secondary capacity trades and the auction and by doing so reduces the search costs and expedites the transaction process;

- providing for the efficient allocation and use of capacity because market participants would be able to readily assess the market value of capacity and make informed decisions; and

- enabling market participants to engage in more effective negotiations and providing them with the confidence that access is being provided on a non-discriminatory basis.

71 Please refer to Recommendation 8 at AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 Final Report, May 2016.

4.4.4 Case studies

The following simplified examples illustrate how market participants would be able to acquire entry and exit capacity rights under the release mechanisms outlined above.

Example 1 - Large industrial customer

In this example, a large industrial customer has a gas supply agreement at Longford and would like to enter into a long-term transportation contract (i.e. 5 years). In this case, the industrial customer would have the option to acquire 5 years' worth of firm entry rights at Longford and firm exit rights at its site through an annual auction of quarterly capacity.

Once the firm entry and exit rights are purchased, there would be no further need for the large industrial customer to participate in the capacity auction process. All this customer would have to do is nominate its gas flows on a daily basis and remain in balance in relation to the system. In many ways, this is akin to the contracting arrangements on contract carriage pipelines, with the only difference being that the rights would be acquired through a transparent and non-discriminatory auction, rather than being negotiated bilaterally.

Example 2 - New entrant retailer

In this example, a new entrant retailer decides to start retailing in Melbourne and to use gas purchased from the hub while it builds up its customer base. In this example, the new entrant retailer would not require entry capacity. Nor would it need to compete in an auction for exit capacity because firm exit capacity rights would be automatically allocated to the retailer based on their end-users demand in the distribution system.

Example 3 - Gas fired generator

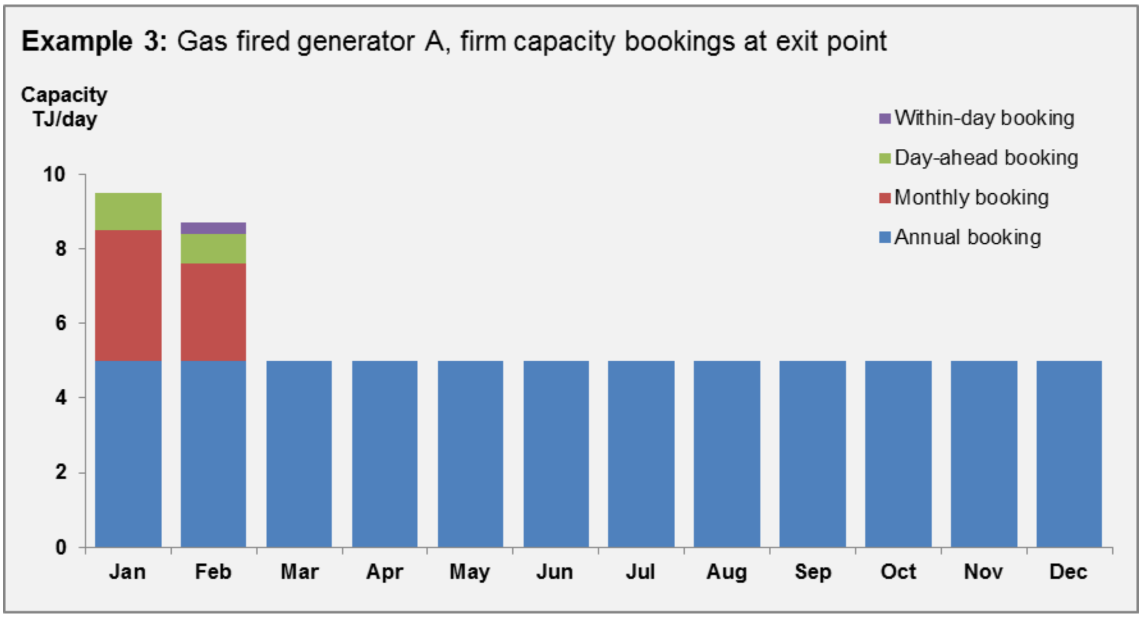
In this example, a gas fired generator has purchased a fixed amount of 5 TJ/day of firm exit capacity rights at generation plant A through the annual auction of quarterly or monthly capacity.

The gas fired generator then decides to purchase some additional exit capacity for January and February, in order to build a seasonal profile. The table and graph below illustrates how this market participant (MP) would have the flexibility to book capacity by acquiring different capacity products.

Table 4.4 Example 3

Exit point (Gas fired generator A)	Entry point
1. If firm unsold baseline capacity available, purchase a firm baseline capacity monthly product for January and February through the annual or month ahead auctions; or 2. If (1) not available, purchase firm day-ahead capacity through the auction of contracted but un-nominated baseline after a specified nomination cut-off time; or 3. If option (2) is not available, purchase *interruptible* day-ahead capacity through either: (a) the day-ahead auction of contracted but un-nominated *baseline* after nomination cut-off time; or (b) the system operator's day-ahead auction of *above baseline* capacity. It is worth noting that at any time the MP can enter into a bilateral trade with another MP (over the counter or through exchange platform) for exit capacity rights for the months of January and February. However, in this case the ability to enter into a bilateral trade would depend on whether the capacity can be traded across exit points.	• The example assumes that the MP has sufficient entry capacity. In particular, entry capacity would be expected to be plentiful in the summer, so it is likely that this MP would have surplus entry capacity it could use. • As an alternative to getting additional entry capacity for January and February, the MP could instead purchase the additional gas at the hub (and so there would be no need to purchase entry rights). • Otherwise, the gas fired generator can use the same options described on the left column to increase its holding of entry capacity (again, noting, that there would be expected to be a surplus of entry capacity at that time of year).

Figure 4.2 Capacity bookings



4.4.5 Capacity sales and trading platform

The Commission recommends that sales of all primary capacity (i.e. baseline / above baseline capacity) should occur through the same platform.

There is also a case for secondary trading of capacity to be conducted through the same platform used for allocation of primary capacity, so that market participants would have a single platform to interact with when trading capacity, minimising transaction costs and complexity. Similarly, this auction/capacity trading platform could be integrated with the commodity trading exchange, so that market participants would be able to obtain gas and transportation services in one centralised location.

There are, however, other options. In particular, conducting secondary trading of capacity through the same platform as the commodity trading exchange while developing a bespoke system for sales of primary capacity might be more consistent with existing systems and regulatory frameworks.[72]

4.5 Investment in new baseline capacity

Under the proposed entry-exit system there would be times when the demand for existing baseline capacity would exceed supply and need to be allocated between parties in the manner described in section 4.4.1. There would also be times when it would be efficient to expand the baseline capacity to meet future demand. A process is therefore required to determine when it is efficient to ration demand versus when it is efficient to expand the baseline capacity.

Through researching similar circumstances in international markets, there appear to be three market-based and market-wide mechanisms that can be used for this purpose:

- open seasons, which allow parties interested in obtaining either existing or incremental capacity to request capacity during a defined window;
- integrated auctions, which involve the auction of both existing capacity and varying levels of incremental capacity; and
- hybrid open season-integrated auctions, which use open seasons to determine whether there is sufficient demand for incremental capacity to warrant carrying out an integrated auction.

Further detail on these three mechanisms is provided in Box 4.9.

Bilateral negotiations between the DTS service provider and market participants are likely to be less effective than the three market-based and market-wide mechanisms identified above for system-wide expansions because they may not canvass all of the

72 The definition of *gas trading exchange* in the NGL is "a facility through which persons may elect to buy and sell natural gas or related goods or services, including pipeline capacity".

potential users of the additional capacity.[73] The Commission's preference is therefore to use one of the three market-based and market-wide mechanisms identified above to signal the need for investment in new baseline capacity in the DTS, where it is feasible to do so.

Box 4.9 Open seasons, integrated auctions and hybrid options

Open seasons

The term 'open seasons' refers to distinct periods of time when parties can request capacity for future periods. Open seasons serve to confirm the collective interest of market participants in making binding commitments to purchase capacity and can relate to incremental capacity only, or a combination of existing unsold capacity and incremental capacity. Open seasons may include both a 'non-binding' and a 'binding' phase. The non-binding phase precedes the binding phase and provides a preliminary gauge on the collective demand for future capacity use by parties.

In a recent review carried out by the Agency for the Cooperation of Energy Regulators (ACER), a number of concerns were raised with the way open seasons have been conducted in Europe. The main concerns were that they tend to provide little transparency about the value of the investment, allocation of risk, how tariffs are derived, the investment tests employed and how capacity is allocated.[74]

Integrated auctions

The term 'integrated auction' refers to an auction that can be used to signal the need for incremental capacity and allocate both existing and incremental capacity.

To carry out an integrated auction, a schedule of increasing price steps must be developed against which parties can indicate their willingness to pay for capacity in the form of a quantity bid for each price. Each price step must be paired with a potential incremental quantity of capacity and would reflect the cost to deliver this capacity. National Grid develops 20 price steps each of which is associated with a 2.5 per cent increase in capacity (equivalent to a 50 per cent capacity increase) and is based on the long run marginal cost.

Once the price steps are established the auction can be conducted. If this results in:

- demand being less than or equal to existing baseline capacity, then the existing capacity would be allocated to the bidding parties at the existing reserve price;

73 Furthermore, under the proposed regulatory and institutional arrangements, AEMO would be responsible for the allocation of existing capacity.

74 Frontier, *Impact Assessment of Policy Options on Incremental Capacity for EU Gas Transmission*, February 2013, pp. 36-37.

- demand exceeding the existing baseline capacity, then if the investment test[75] is:
  - satisfied and a decision is made to expand capacity, the bidding parties would pay the price step associated with the relevant capacity expansion; or
  - not satisfied, existing capacity would be allocated at the price where demand is less than or equal to the existing baseline capacity.[76]

The main benefits of integrated auctions are that they are non-discriminatory and provide a market based mechanism to allocate existing and incremental capacity. They can, however, be costly to carry out and the value in carrying out regular auctions is questionable if there is little indication of the need for additional capacity.

Hybrid open season-integrated auctions

The hybrid open season-integrated auction overcomes some of the perceived shortcomings of the integrated auction by requiring a non-binding open season to be conducted before a decision is made to proceed with the integrated auction and the design and costing phases can start. If the open season reveals that there is sufficient interest amongst market participants to expand the capacity of the pipeline, then the integrated auction would proceed. If, on the other hand, there is insufficient interest then the integrated auction would not be carried out and existing capacity sold through the standard auction process.

Use of mechanisms in other entry-exit systems

The application of these mechanisms has differed in other entry-exit systems, with pipeline operators in continental Europe traditionally using open seasons while National Grid has used integrated auctions. Recent reviews in both of these jurisdictions have, however, resulted in some changes to these approaches. For example:

- ACER has recently recommended that future investment in incremental interconnection capacity in the EU be signalled and allocated through the hybrid open season-integrated auction.[77] The European Commission is yet to endorse this recommendation, but if it is approved it would take effect in July 2017.

75 In Great Britain, the investment test requires the present value of revenue from the bids for incremental entry capacity to exceed a 50 per cent threshold for up to 32 quarters from release. The investment test in rule 79(2)(b) of the NGR, on the other hand, requires the present value of the incremental revenue from forecast demand to exceeds the present value of the investment cost.

76 If the auction cleared at price step 2 or above, it may be possible to consider smaller expansions.

77 ACER, *ACER Recommendation on the amendment to the Network Code on Capacity Allocation Mechanisms in gas transmission systems*, October 2015.

- In 2015 National Grid introduced a new mechanism to reserve incremental capacity. This new mechanism, which is referred to as the Planning and Advanced Reservation of Capacity Agreement (PARCA),[78] allows market participants to reserve incremental capacity through direct negotiations with National Grid and pay for the capacity once planning permissions have been obtained and capacity allocated. National Grid is required to inform the market when a PARCA is requested and give others an opportunity to request capacity through an open season process. This change was, in part, driven by a concern that under an integrated auction market participants have to make a financial commitment to pay for incremental capacity but are subject to increasingly long and uncertain planning processes in Great Britain.

The only points in the DTS where it would not be feasible to employ this type of mechanism are the distribution connected exit points where capacity would be dynamically allocated to market participants based on the volume of gas consumed by their end-customers (see section 4.4.1). The nature of demand at these points is such that it is unlikely to be possible to get long-term commitment, and therefore any useful investment signals, from retailers. An alternative approach is therefore required at these points in the DTS.

The Commission understands that investment at distribution connected exit points is currently signalled through a bilateral planning process (involving the DTS service provider and the distribution businesses), and that as part of this process consideration is given to forecast demand, planning standards and other technical requirements.

The Commission recommends that capacity expansions at distributed connected exit points continue to be signalled through this planning process, with any investment proposal approved by the AER as part of the Access Arrangement review process.

In relation to the other entry and exit points in the DTS, the Commission recommends that a market-based and market-wide process be used. Of the three options, the Commission's preference is for the hybrid open season-integrated auction to be employed, if it is feasible to do so. If this is not feasible, then the stand-alone open season should be used and overseen by the AER.

The benefits that the hybrid open season-integrated auction offer over the stand-alone open season and integrated auctions are that:

- The open season element can be used to identify whether there is likely to be a need to expand capacity before any costs are incurred investigating the expansion options and developing the price steps for varying levels of expansions. The open season can also be used to identify where the capacity expansions are required and the likely level of demand, which would inform the design phase if the integrated auction is to be carried out.

78 National Grid, *Planning and Advanced Reservation of Capacity Agreement (PARCA) Overview*, October 2013.

- The integrated auction element can be used to allocate both existing and incremental capacity in a non-discriminatory and transparent manner if the proposed expansion is found to satisfy the new facilities investment test in the NGR.

The way in which the hybrid open season-integrated auction could work in the DTS is described below. Before moving on though, it is worth noting that this process is not only expected to provide an indication of whether shallow expansions at the entry and exit points are required. It would also provide an indication of whether deep investments through the system are required to enable the entry and exit capacity to be provided (i.e. the capacity expansion will need to support flows through the network to the relevant entry/exit point).

4.5.1 Proposed hybrid open season - integrated auction

Under the proposed hybrid open season-integrated auction, a non-binding open season would be conducted at *least* every two years and if this process identifies the need for an expansion of the DTS, then:

- the DTS service provider would be required to:
  - investigate the options for expanding capacity (the design phase); and
  - submit a proposal to the AER setting out the details of the expansion options and proposed price steps for the entry and/or exit capacity that would be subject to the integrated auction (the pricing approval phase).
- the AER would be responsible for approving the price steps used in the auction; and
- AEMO would be responsible for conducting the integrated auction.

The term 'at least' has been italicised in the paragraph above because if there are indications from the market that additional capacity is required sooner, then the open season could be conducted earlier.

Non-binding open season process

The open season would ideally be conducted shortly after the release of AEMO's Victorian Gas Planning Report, so that market participants can be as informed as possible about forecast demand and supply conditions in the DTS. The NGR currently require AEMO to publish this review on a biennial basis, no later than 31 March.

Participation in the open season would be open to existing and prospective users of the DTS. Because the scope and cost of any expansion would not be known before the open season is conducted, participants in the open season would not be required to make binding offers through this process. They would instead be required to submit an expression of interest that indicates their likely willingness to commit to purchasing additional capacity at the relevant entry and exit points. While this stage would be non-binding, market participants would be expected to act in good faith and provide realistic indications of their expected demand for capacity through this process.

During the open season, the DTS service provider would be able to engage with the participants that have indicated an interest in acquiring additional capacity to determine what their specific requirements are and the timing of those requirements, which would inform the design phase if the integrated auction is to be carried out. This process would also enable the DTS service provider to assess the authenticity of a participant's request.

If the open season reveals that there is sufficient demand to warrant further consideration of an expansion, then the design phase could commence.

Design phase and price step approval phase

During the design phase, the DTS service provider would be required to:

- identify the option(s) for expanding capacity to meet the demand at the relevant entry and exit points identified through the open season;[79]
- carry out any technical work that is required on these options (e.g. a front end engineering and design study) and estimate the costs associated with each option;
- develop the price steps associated with the expansion options for the relevant entry and/or exit points;
- prepare a submission for the AER, setting out the expansion options, the price steps associated with each option at the relevant entry and/or exit points and when the capacity could be made available.

The AER would then consult with interested parties and determine whether or not to approve the proposed price steps (which would become the new reference tariffs if any of the expansions proceed) having regard to the relevant NGR tests and principles.

Integrated auction

Once the price steps are approved by the AER, the integrated auction would be carried out as part of the standard annual auction of longer term capacity. At a high level, the auction process would involve the following:

- a price schedule would be circulated to registered participants; and
- market participants would then bid the quantity of capacity they want in each quarter and at each price step.

Once the auction is complete, the DTS service provider would assess the level of demand arising from the auction. If the demand is less than the existing baseline

79 These alternatives would need to be considered because at the time the open season is conducted prices would not be known, so it is possible that market participants may seek more or less capacity once they are aware of the price.

capacity level, then the auction would clear at the current reference tariff. If, however, demand exceeds the baseline capacity level, then the DTS service provider would be required to assess whether the proposed expansion is likely to satisfy the new capital expenditure criteria in rule 79 of the NGR. This rule requires capacity expansions to be such that would be incurred by a prudent service provider acting efficiently and to be justified on one of the following grounds if it is to be rolled into the regulatory asset base:[80,81]

- the overall economic value of the expenditure is positive (rule 79(2)(a)); or
- the present value of the expected incremental revenue to be generated as a result of the expenditure (which could be based on the bids received and any additional demand that is forecast to arise in the future) exceeds the present value of the capital expenditure (rule 79(2)(b)).

If the DTS service provider finds that the capital expenditure criteria are:

(a) **unlikely to be satisfied** (e.g. because there is insufficient demand to warrant the investment), then the existing baseline capacity would be allocated amongst bidders at the price step where demand is less than or equal to the existing level of baseline capacity;[82]

(b) **likely to be satisfied**, it would then be up to the DTS service provider to determine whether to:[83]

  — **proceed with the expansion**, in which case the existing and incremental capacity (when it becomes available) would be allocated to bidders at the price step associated with the expansion; or

80 Note that if the capital expenditure was not justifiable on one of these grounds, the expansion could still be carried out but it would be treated as speculative capital expenditure under rule 84 of the NGR, rather than conforming capital expenditure.

81 In the March 2016 Discussion Paper, the Commission noted the potential to employ a similar investment test to that used in Great Britain (i.e. the present value of revenue from the bids for incremental entry capacity to exceed a 50 per cent threshold for up to 32 quarters from release). The submissions received in response to this proposal suggest that this test would be inconsistent with rule 79 of the NGR and that even if this rule was changed, the DTS service provider would be unlikely to expand capacity on this basis because of the risk it would expose them to, particularly given the redundant asset provisions in the NGR. The discussion in this section therefore assumes that the investment test embodied in rule 79 of the NGR continues to operate in the same manner that it currently does.

82 One other option that would be open to the DTS service provider is to investigate smaller expansions offered through the integrated auction. This would only be relevant though if the demand exceeded the first price step.

83 There is no explicit requirement in the NGR for pipeline operators to expand capacity if the new capital expenditure criteria are met, but if the access dispute provisions are triggered a pipeline operator may be required by rule 118(2) to expand capacity, subject to the caveat that the extension and expansion requirements of the applicable access arrangement provide for the relevant funding, it is technically and economically feasible and consistent with the safe and reliable operation of the pipeline. If this was to occur and it later turned out the capacity was not required, then the AER would need to carefully consider whether the redundant asset provisions should be applied to this expansion.

– **not proceed with the expansion**, in which case the existing baseline capacity would be allocated amongst bidders at the price step where demand is less than or equal to the existing level of baseline capacity.

Further insight into how the integrated auction would work in practice can be found in Box 4.10, which contains some simplified examples.

Box 4.10 Integrated auction example

The table below provides some examples of how the integrated auction works. In both of these examples, the baseline capacity is 1,300 TJ/day and five alternative capacity expansions are offered, each of which has a unique price step.

Integrated auction examples

Available Capacity Supply (TJ/day)	Price Step	Price ($/GJ)	Auction Bids Demand (TJ/day)	
			Example 1	Example 2
1,550	P5	$0.45	1,175	1,200
1,500	P4	$0.42	1,200	1,250
1,450	P3	$0.40	1,225	1,275
1,400	P2	$0.38	1,250	1,325
1,350	P1	$0.36	1,295	1,340
1,300 (existing capacity)	P0	$0.34	1,295	1,350

- In the first example, demand is 1,295 TJ/day, which is lower than the existing level of baseline capacity (1,300 TJ/day), so the existing capacity would be allocated to the bidding parties at P0 ($0.34), leaving 5 TJ/day of spare capacity.
- In the second example, demand is 40 TJ/day higher than the existing baseline capacity level (1,340 TJ/day v 1,300 TJ/day). Before a decision is made to expand, consideration would need be given to whether the new capital expenditure criteria are likely to be satisfied:
  – if they are likely to be satisfied and the DTS service provider decides to carry out the expansion, then all bidding parties would pay $0.36/GJ.
  – if they are unlikely to be satisfied, then the existing capacity would be allocated at the price where demand is less than or equal to the existing baseline capacity of 1,300 TJ/day, which in this case is $0.34/GJ.

If the timing of the hybrid open season-integrated auction process aligns with the Access Arrangement review process and the DTS service provider decided to expand the capacity of the DTS, then the AER would be able to consider the proposed expansion through that review process. If, however, the hybrid open season-integrated auction process occurs during the Access Arrangement period and the DTS service provider wanted some comfort that the AER would allow the proposed expenditure to be rolled into the regulated asset base, it could either:

- make an application under rule 80 of the NGR to the AER for an advance determination that the proposed expenditure will meet the new capital expenditure criteria, which if made would be binding on the AER; or
- include a trigger event provision in its Access Arrangement, which would allow the Access Arrangement (or certain parts of the Access Arrangement) to be amended if the AER finds that the proposed expenditure meet the new capital expenditure criteria.[84]

The main difference between these options is that under the first option no changes would be made to the Access Arrangement (e.g. to reflect the expenditure, higher demand or new reference tariffs) until the next review date while under the second option the Access Arrangement would be amended in the Access Arrangement period.

In terms of the AER's assessment of whether the expenditure is likely to be justified under rule 79(2)(a) or 79(2)(b), the outcome of the auction would enable the AER to make a more informed decision about whether there is likely to be sufficient demand to warrant the expansion because it would:

- provide a clear indication of the willingness of market participants to commit to underwriting the expansion; and
- provide a better basis for assessing any demand forecasts that must be considered as part of the assessment.

In relation to the latter of these points, it is worth noting that the integrated auction may not result in market participants committing to 100 per cent of the expanded capacity, particularly if the expansion asset has a relatively long life (e.g. 30-80 years). In this case, market participants may only be willing to purchase capacity for the first 10-15 years of the asset life. The AER's assessment of whether rules 79(2)(a) or (b) are likely to be satisfied in this case would therefore need to take into account both the commitments made through the integrated auction process and any additional demand that is forecast to arise over the life of the asset.

When compared with the assessment approach currently employed in the DTS, which is wholly reliant on demand forecasts, it is clear that the results of the hybrid open season-integrated auction will provide the AER with a better basis on which to

84 This re-opening provision could operate in a similar manner to the contingent project provisions in the National Electricity Rules.

determine whether the new capital expenditure criteria are likely to be satisfied even in circumstances where market participants provide less than 100 per cent commitment.

Overall process

It is difficult to know at this stage how long the whole process could take, but based on international experience it could take up 18 months to complete if the open season indicates that the integrated auction should be carried out.[85] If there is insufficient demand during the open season, then the process could take as little as a month.

It would be important throughout this process to be as transparent as possible about the outcomes of the various phases. The Commission would therefore expect the results of the open season and the integrated auction to be published, along with the DTS service provider’s pricing proposal and its assessment of whether the capital expenditure is likely to satisfy the new capital expenditure criteria.

Observations

To give effect to the hybrid open season-integrated auction outlined above, a number of changes would need to be made to the NGR and potentially to the NGL to, amongst other things, require:

- the open season to be conducted at least once every two years and to progress to an integrated auction if there is sufficient demand to do so;
- the AER to determine whether or not to approve the price steps proposed by the DTS service provider before the integrated auction is carried out, which would be a separate process from the Access Arrangement review process; and
- the results of the open season and integrated auction to be published.

While this process may appear relatively complex, the Commission would prefer for it to be transparently set out in the regulatory frameworks. Although allowing the DTS service provider full discretion to negotiate and determine capacity expansions may appear simpler, this would either risk a complex but opaque process or a process that leads to less efficient outcomes. The Commission’s preference is for the process to be incorporated into the NGR so market participants have confidence that it would be carried out in a transparent and non-discriminatory manner and would efficiently co-ordinate all market participants’ interests.

Of the three market-based and market-wide mechanisms in use in other jurisdictions, the hybrid open season-integrated auction is more complex than the stand-alone open

85 This estimate assumes that the open season takes one month, the design phase takes seven months, the AER approval phase takes seven months and the integrated auction and assessment phase takes three months.

season option[86] but it has other benefits that more than offset this complexity (i.e. the integrated auction element uses a market based mechanism to efficiently allocate new capacity). The hybrid open season-integrated auction is also superior to a stand-alone integrated auction option, because it allows the costs of carrying out the integrated auction to be avoided if there is insufficient demand for additional capacity. The Commission's preference is therefore for the hybrid open season-integrated auction to be employed.

4.6 Implications for the economic regulatory framework

To give effect to the recommendations set out in this chapter, significant changes would need to be made to the DWGM Rules in Part 19 of the NGR. Some minor refinements to Parts 8-12 of the NGR may also be required. To the extent that any changes to the NGL are required, they are likely to be minimal, given the Commission is recommending that most of the institutional arrangements continue to operate as they currently are (see Chapter 6).[87]

Before setting out the changes that are likely to be required to the economic regulatory framework in the NGR, it is worth noting that the move to the entry-exit system would not alter the rationale for regulating the DTS. Nor would it change:

- the overarching objective of economic regulation, which is to promote the promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas; or
- the revenue and pricing principles, which amongst other things, state that the DTS service provider should be provided with:
  - a reasonable opportunity to recover at least the efficient costs of providing reference services and complying with regulatory obligations; and
  - effective incentives to seek out the least-cost way of providing services on the DTS, promote the efficient use of the DTS and carry out efficient investment in the DTS.

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86 It is worth noting that many of the steps required by this process would also be required if a stand-alone binding open season was used. For example, if a stand-alone open season was carried out the DTS service provider would also need to engage with prospective users to determine what their capacity requirements are and if there is sufficient demand for incremental capacity they would also need to: investigate the capacity expansion options; estimate the prices that would apply to the capacity expansion and determine what the level of demand is at these prices; and assess whether the expansion is likely to satisfy the new capital expenditure criteria and, if so, allocate the expanded capacity. The only additional work that the DTS service provider would need to do under the hybrid option is develop price steps for a number of capacity options and have these approved by the AER. While this is not a trivial exercise, there are steps that can be taken to try and streamline this process. For example, the rules could specify the methodology to be used, or the AER could be required to publish a guideline setting out the methodology to be used and how it would assess proposals.

87 The most likely cause of NGL changes would be revisions to institutional functions.

The movement to the entry-exit system would nevertheless necessitate some changes to the economic regulatory framework. A summary of the changes that could be required if all the recommendations set out in this chapter are implemented is provided in Table 4.5. As this table reveals, most of the changes would be required to give effect to the recommendations that:

- the AER be accorded responsibility for approving the baseline capacity;
- baseline capacity be released to the market in the manner described in section 4.4.1;
- an auction of contracted but un-nominated capacity be carried out on contractually congested points of the DTS; and
- a market-based mechanism, such as the hybrid open season-integrated auction, be used to signal the need for further investment in the DTS and to allocate the expanded capacity.

Table 4.5 Summary of potential changes to the NGR and the NGL

<table>
<tr><th>Topic</th><th colspan="2">Rationale for changes</th></tr>
<tr><td rowspan="2">Baseline capacity</td><td>Proposal</td><td>Under the proposed model:
• the AER would be responsible for approving the baseline capacity as part of the Access Arrangement review process; and
• the non-price terms and conditions in the DTS service provider's Access Arrangement would specify its liability for not making firm capacity available (subject to the standard contractual limitations, such as force majeure events or planned maintenance where sufficient notice has been provided and any limitations arising from the fact the DTS service provider is not responsible for operating the system).</td></tr>
<tr><td>Changes</td><td>To give effect to these recommendations, new provisions would need to be included in the NGR to:
• accord the AER responsibility for approving the baseline capacity and set out:
— the process to be followed by the AER, the DTS service provider and system operator when determining baseline capacity;
— any principles the AER is required to consider when making its determination; and
— how the baseline capacity would be adjusted between reviews to account for expansions or contractions in capacity.
• require the Access Arrangement to specify the baseline capacity and the DTS service provider's liability for not making firm capacity available.</td></tr>
<tr><td>Release of existing baseline capacity</td><td>Proposal</td><td>Under the proposed model:
• the DTS service provider would continue to provide a single service to the system operator, the Tariffed Transmission Service, which for the purposes of Parts 8-12 of the NGR would be the Reference Service;</td></tr>
</table>

Topic	Rationale for changes	
		• auctions would be used to release entry, counterflow and most exit capacity and a portion of capacity reserved for shorter-term auctions; • a dynamic allocation mechanism would be used to allocate capacity at distribution connection points; • the AER would be responsible for approving on an *ex ante* basis the reference tariffs for all entry, exit and counterflow services provided using baseline capacity, which in the case of auctioned capacity would become the reserve price; • if the price at which the auction clears exceeds the reference tariff, the price differential would either be: — returned to market participants in subsequent years in the form of lower reference tariffs; or — used to offset AEMO's congestion management costs and/or market participant fees; and • if at the time the entry-exit system is introduced there is some uncertainty about demand, then the AER can consider whether a revenue cap form of regulation should be employed having recourse to the existing principles in the NGR.
	Changes	To give effect to these recommendations, changes to the NGR may be required to: • require baseline capacity to be sold using the release mechanisms set out above and a portion of the baseline capacity that would otherwise be auctioned to be reserved for contracts with a duration of one year or less; • specify the form that capacity auctions would take, the frequency with which the auction would occur, the process to be followed and how any additional revenue generated by the DTS service provider through the auctions of baseline capacity should be treated; and • specify any additional principles the AER is to have regard to when approving the reference tariffs for entry, exit and counterflow capacity.

Topic	Rationale for changes	
Auction of contracted but un-nominated capacity	Proposal	Under the proposed model, an auction of contracted but un-nominated capacity with a zero reserve price would be carried out on a daily basis shortly after the nomination cut-off time, if capacity at a particular entry or exit point is contractually congested. The proceeds from these sales would be retained by the system operator and used to offset the costs incurred in providing balancing services.
	Changes	To give effect to this recommendation, new provisions would need to be included in the NGR to set out the circumstances in which this auction would need to be conducted and to direct where the proceeds from the auction would go.
Investment in new baseline capacity	Proposal	Under the proposed model, investment in new baseline capacity would ideally be signalled in the following ways: • at distribution exit points the need to expand capacity would be signalled in the same manner it currently is; and • at all other entry and exit points, the need to expand capacity would, where feasible, be signalled through a hybrid open season-integrated auction.
	Changes	To give effect to the latter part of this recommendation, new provisions would need to be included in the NGR to set out the process to be followed and roles to be played by the DTS service provider and the AER under the hybrid open season-integrated auction. New provisions may also be required to set out how the price steps in the auction should be calculated, or to allow the AER to determine this through a guideline.

While the changes identified in Table 4.5 would not alter the way in which the DTS service provider's revenue requirement is calculated, it would result in changes to the ways in which:

- the DTS service provider recovers its revenue requirement;
- the reference tariffs in the DTS are determined;
- the non-price terms and conditions of access to the DTS are defined; and
- new investment opportunities in the DTS are signalled and evaluated.

It would also result in the AER becoming responsible for:

- approving the baseline capacity for the DTS as part of the Access Arrangement review process; and
- approving the price steps[88] that would be used in an integrated auction, if the open season reveals there is sufficient demand to warrant carrying out the auction.

Finally, it is worth noting that the changes to Parts 8-12 of the NGR are expected to be relatively minor because the provisions in this section of the NGR are sufficiently flexible to accommodate the economic regulation of a number of different pipeline types and carriage models. Part 19 of the NGR (the current DWGM rules), on the other hand, would need to be completely redrafted to accommodate the recommendations set out in this chapter and those contained in chapters 2 and 3.

88 If an expansion occurs, then the relevant price step would become the new reference tariff, which is why it must be approved by the AER.

Table 4.6 Summary of required, preferred and suggested features of the Commission's recommendations

	Required design features	Preferred design features	Suggested design features
Recommendation 3: The Southern Hub would have explicit and tradeable capacity rights for entry to and exit from the DTS.			
Capacity calculation			
Baseline capacity	• Baseline capacity would be calculated through a transparent process with the DTS service provider proposing the level of baseline capacity and the AER approving such level after consultation with industry participants. • Baseline capacity would be calculated with the aid of load flow modelling software, taking into account forecast demand and planning standard.		• Seasonal baseline capacity would be developed in order to maximise the release of firm capacity during the year.
Above baseline capacity	• Above baseline capacity would be determined by AEMO on a short-term basis, based on the expected pattern of flows and operational constraints on the network each gas day. • Above baseline capacity would be calculated in a similar manner to the baseline capacity, with the aid of load flow modelling software.		

	Required design features	Preferred design features	Suggested design features
		Capacity products	
Standardised capacity products	• Entry, exit and counterflow products should be developed. • Firm and interruptible products should be developed, with firm capacity available for a range of contract tenors and interruptible entry and exit capacity only available on a day-ahead and within-day basis. Interruptible counterflow capacity should be available for all contract tenors. • Standardisation would occur in consultation with industry and provide for standardised entry / exit / counterflow points (or zones if appropriate), contract lengths, capacity metrics (GJ/d or GJ/h) and other conditions. • To the extent relevant, the standardised products should mirror the commodity products to be sold through the exchange.	• Renomination rights should be included in the standardised product to enable market participants to manage intra-day changes, but limits are likely to be required to facilitate the release of contracted but un-nominated capacity. • Operational, prudential and other contract provisions should, where relevant, be based on the standardised provisions that the GMRG has been accorded responsibility for developing for contract carriage pipelines.	• Contract lengths would include: — longer-term products: quarterly products for up 10 or 15 years (i.e. 40-60 quarters) and monthly products for the next year (i.e. 12 months); and — shorter-term products: month-ahead, weekly, day-ahead and within-day products. • If there is sufficient demand for an hourly product, and if feasible, capacity should be defined on an MHQ basis, otherwise it should be defined on an MDQ basis with either a flat hourly flow or a minimal amount of hourly flexibility (e.g. a 1.1 hourly load factor) and consideration given to whether additional hourly flexibility can be provided to those that require it.
		Capacity release and allocation mechanisms	
Existing baseline capacity	• There would be auctions to release existing baseline capacity at entry points, and interconnection, storage and direct connect exit points.		• The auction of longer-term products should take the form of an ascending clock uniform price auction, if it is feasible to do so. If this is not feasible a

	Required design features	Preferred design features	Suggested design features
	• Existing baseline capacity at distribution exit points would be dynamic allocated. • The AER would be responsible for approving reference tariffs (which would form the basis for the reserve prices used in the auctions) and determining how any over or under recovery of revenue or prices be treated.		sealed bid uniform price auction should be considered. • The auction of shorter-term products should take the form of a single round sealed bid uniform price auction. • A fixed proportion of the baseline capacity should be reserved for shorter-term auctions (e.g. monthly, month ahead, day ahead or within day products).
Transitioning AMDQ and AMDQ cc		**AMDQ** • Tariff V AMDQ and Tariff D AMDQ holders at distribution exit points would be automatically allocated firm capacity through the dynamic allocation process. • Tariff D AMDQ holders at non-distribution exit points would have the option to acquire an allocation of firm capacity rights up to their current AMDQ holding for as far into the future as capacity is made available. Those Tariff D customers that are supplied by a retailer would be able to assign the firm rights to the retailer for the duration of their retail contract. **AMDQ cc** • A similar approach to that proposed for	

	Required design features	Preferred design features	Suggested design features
		Tariff D AMDQ holders at non-distribution exit points would be applied but capacity could only be obtained for the remaining term of their AMDQ cc contract.	
Above baseline capacity	• Above baseline capacity would be allocated through a day-ahead auction, with capacity rights to be offered on an interruptible basis. • The capacity would be released by system operator at entry and exit points where baseline capacity has been fully sold. • Revenue from the auction would accrue to AEMO to offset unallocated congestion costs and participant fees.		• The auction would be a single round sealed bid auction with a zero reserve price.
Measures to encourage the release of secondary capacity			
Auction for contracted by un-nominated baseline capacity	• There would be a daily, day-ahead auction for contracted but un-nominated capacity at points with contractual congestion. • Auction happens shortly after a specified nomination cut-off time. • The auction would have a reserve price of zero.	• The auction would sell capacity in firm and interruptible components, with the interruptible component only released when the firm component is sold. The original owner would retain the right to increase nominations where its capacity has not been sold on an firm basis. • The auction would be a single round auction with a first price rule, where bidders pay the value of their winning bid, to reduce complexity.	

	Required design features	Preferred design features	Suggested design features
Secondary capacity trading	• An electronic exchange would be created that would enable market participants to trade secondary capacity on an anonymous basis. • Trades carried out through the capacity trading platform would be given effect through an operational transfer. • Information on all secondary trades, including the price of the trade plus any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties would be published.		• Trades conducted outside the capacity trading platform to be advertised ahead of time on the capacity trading platform listing service.
	Investment in new baseline capacity		
New baseline capacity	• Investment in new baseline capacity for entry and exit points (other than distribution connected exit points) would be signalled by market participants' commitment buy entry or exit rights. • Investment to support flows to distribution connection exit points would be determined through the same approach that is currently used.	• Hybrid open season / integrated auction would be used to signal market participants' commitment buy entry or exit rights provided by a capacity expansion. This would be conducted at least every two years.	

5 Settlement and credit risk management

The operation of commodity trading, capacity auctioning and trading, and balancing at the Southern Hub will result in financial transactions that must be settled. All trading activity will result in matched payments and charges, so it is important that the credit risk management approach ensures the buyer is always able to pay the seller.

The Southern Hub will feature a consistent settlement and prudential management approach by the exchange and system operators. This is likely to be aligned with the approaches in place at the Northern Hub (Wallumbilla gas supply hub) and the Short Term Trading Market (STTM).

Key designs features of the settlement and prudential approach include:

- **Centralised settlement:** The relevant operator will calculate the settlements amounts and issue settlement statements for each billing period, collect payments from those market participants owing money for the billing period, and make payments to those owed money for the billing period.
- **Centralised credit risk management:** Market participants will post collateral with the relevant operator to cover their potential settlement exposure.
- **Ongoing prudential assessments:** The relevant operator will estimate each market participant's exposure regularly, and monitor it against trading limits. Exceeding the trading limits will trigger escalating credit management processes.
- **Real time prudential assessments for exchange based trading**: Before a trade is finalised, the exchange operator will validate that cumulative trade since the last assessment will not result in a market participant exceeding their trading limit. In the event that the limit is exceeded, the participant will need to increase its collateral before the trade can proceed.

These features are described in more detail below.

5.1 Role of the operators

The system operator would manage system operation and capacity allocation. System management includes operating the transmission pipeline, managing the residual balancing (see section 3.3) and maintaining system security (see section 3.5). Capacity management includes auctioning firm, interruptible, and contracted but un-nominated capacity (see section 4.4), keeping records of capacity rights owned by market participants, charging for capacity overruns and charging the DTS Service Provider for capacity that is not available in accordance with the provisions of the SEA.

The exchange operator would manage the trading platform used for commodity trading (including residual balancing actions and system security actions by the system operator). Cash flows associated with commodity sales would match revenues from purchases. As discussed in section 4.4.5, it is possible that the exchange may also be used for secondary capacity trading and the arrangements discussed in this chapter allow for that possibility.

Both operator roles would charge fees to cover internal operating costs.

5.2 Centralised settlement

The exchange operator or system operator will determine the settlement amounts for each billing period that are payable by the market participant to the operator, or are payable by the operator to market participants.

The system operator will have the following settlement amounts:

- residual balancing action amounts;
- reconciliation amounts;
- system security action amounts;
- capacity auction premia;
- capacity overrun charges;
- capacity unavailability charges;
- neutrality fund amounts;
- ad hoc settlement amounts; and
- operator fees and charges.

The exchange operator will have the following settlement amounts:

- commodity trading settlement amounts;
- potentially, capacity trading settlement amounts; and
- operator fees and charges.

5.2.1 Residual balancing action amounts

The system operator will need to recover the net costs of residual balancing actions. These costs would be positive for the purchase of additional gas through the exchange and negative (i.e. revenue) where the system operator has sold gas.

The net costs allocated to market participants (see section 3.3.4) during the billing period will be aggregated to either a residual balancing action charge (where a market participant is charged by the system operator) or a residual balancing action payment (where a market participant is paid by the system operator), depending whether the participant was a 'causer' during a period when the system was short or long.

If an average cost charging methodology is used, market participant charges/payments will exactly balance the system operator's net costs.

5.2.2 Reconciliation amounts

Reconciliation amounts would arise from differences between actual entry and exit flows and the NRT allocated exit flows used to determine a market participant's POS. These would be settled at the neutral gas price for the day (see section 3.2.7). Reconciliation amounts for all gas days in a billing period would be aggregated to either a reconciliation payment (where a market participant is paid by the system operator) or a reconciliation charge (where a market participant is charged by the system operator).

5.2.3 System security action amounts

The system operator will need to recover the net costs of system security actions. These costs would be positive for the purchase of locational gas through the exchange and negative (i.e. revenue) where the system operator has sold gas on a locational basis. Buying back capacity rights would also represent a cost to the system operator.

These net costs would be recovered through a number of charges, as described in the following four sections. The first three of these charges are associated with issuance of additional capacity, the over-usage of capacity and the under-provision of capacity by the DTS service provider (i.e. factors that could contribute to the need to buyback capacity or otherwise resolve a capacity constraint).

As noted in section 3.5, there is currently no charge in the 'target' model equivalent to surprise uplift in the current DWGM design, although the Commission considers that further work should be undertaken in this area. In the event that an equivalent charge was subsequently adopted, this would also be used to fund the net costs of system security actions.

5.2.4 Capacity auction premia

The system operator would be responsible for auctioning capacity (firm, interruptible, and contracted but un-nominated capacity). It would retain the proceeds from the auctions of short-term, interruptible capacity, which would have a zero reserve price. It might similarly retain any premia received above the reserve price for long term capacity (see section 4.4.1), where the reserve price would be the reference tariff (with the reference tariff being paid to the DTS service provider by market participants through the Transmission Payment Deed).

5.2.5 Capacity overrun charges

A market participant would incur a capacity overrun charge if its flows at an entry or exit point exceeded its available capacity at that point. The Commission recommends that the GMRG consider whether market participants should be prohibited from nominating in excess of capacity rights (see section 3.2.5).

5.2.6 Capacity unavailability charges

If the capacity of the declared transmission system was less than the firm capacity as a consequence of the DTS service provider not meeting the service envelope agreement, the DTS service provider would incur a capacity unavailability charge (see section 4.2.3).

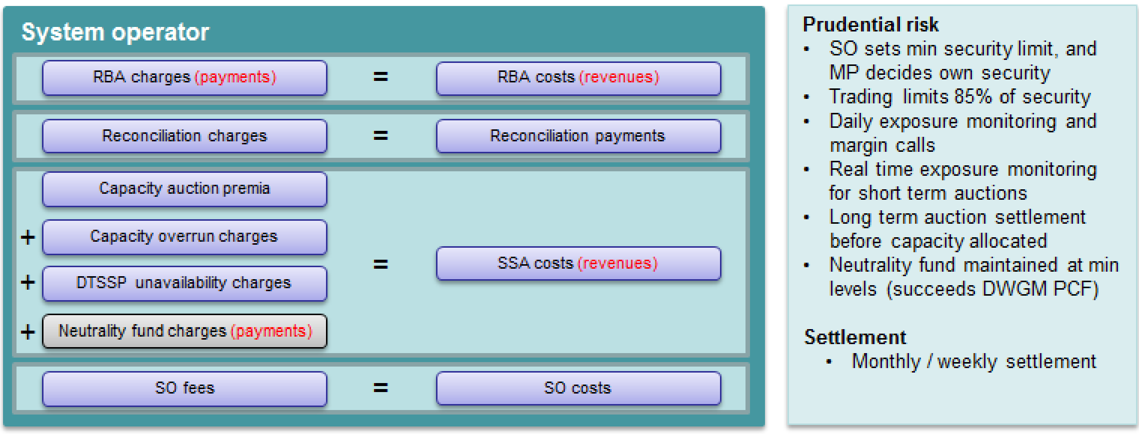
5.2.7 Neutrality fund amounts

The capacity auction premia (from section 5.2.4) retained by the system operator together with receipts from capacity overrun charges (section 5.2.5) and from capacity unavailability charges (section 5.2.6) will not precisely match the net costs of system security actions (section 5.2.3) to be recovered. The Commission hence recommends that the GMRG examine the establishment of a neutrality fund to balance these items.

The neutrality fund would be maintained at minimum levels[89] and surplus or shortfalls could be charged to or recovered from market participants on a socialised basis (such as exit flows). Consideration should be given to the period over which the level of the charge/credit would be fixed:

- a short period (e.g. one day) would minimise the size of the fund necessary/the potential costs to the system operator of borrowing funds but could be difficult for market participants to forecast/manage; whereas
- a longer period (say six months) would provide more certainty to participants but may be more costly in terms of establishing the fund/borrowing costs.

Figure 5.1 Ring fenced, cost neutral System Operator role



89 The fund may include the residue of the DWGM participant compensation fund as at transition.

5.2.8 Operator fees and charges

The market and system operators would need to recover their costs on an appropriate, cost reflective basis. The current arrangements for the recovery of exchange fees and DWGM participant fees are likely to represent an appropriate starting point for determining how these costs would be recovered.

5.2.9 Trading settlement amounts

Trading settlement amounts cover the charges to buyers of commodity (or capacity) products on an exchange, and the payment to sellers of the product, and are calculated by multiplying the transaction quantity by the transaction price.

Further refinements to trading settlement amounts could include a reallocation service to reflect any off-market financial arrangements.

All payments and charges over the billing period would be netted to either a trading settlement amount payment or a trading settlement amount charge for the billing period.

5.2.10 Settlement timing

The DWGM operates on a billing period of one month, with settlement statements issued after the end of the month as preliminary (for information purposes), final (for payment of settlement amounts) and revision (for payment of revised settlement amounts). Payment of final settlement amounts takes place two business days after the final settlement statements are issued, and revised settlement amounts are payable with the next final settlement statement to be issued. The DWGM settlement timings are aligned with the preliminary and final settlement statement timings in the short term trading market (STTM), but the revision settlement is issued later in the STTM to align with the longer meter reading cycles outside Victoria.

The choice of settlement period affects the amount of security that must be posted. The longer the settlement period, the larger the settlement amounts may be, and the larger the security must be. Because the National Electricity Market (NEM) is a gross market with much larger settlement amounts (all generators are paid, and all market participants are charged), it is appropriate to have a short one week billing period.

In the Southern Hub, market participants would be able to meet their demand from their own supply portfolio, and the settlement amounts may remain relatively small. As liquidity grows, and as more gas is traded between market participants at the virtual hub, settlement amounts will grow, and a shorter billing period may be indicated.

The Commission suggests that settlement timing for the Southern Hub is aligned with that of the DWGM, and that the GMRG considers how to allow for shorter billing periods to be introduced in the future.

5.3 Centralised credit risk management

Settlement amounts are revenue neutral (the payments to market participants equal the charges on market participants).[90] Accordingly, the Southern Hub must ensure that all market participants owing money are in a position to pay the operator, or the operator will not be able to make payments to those market participants who are owed money.

5.3.1 Credit risk approach in existing markets

The DWGM (and other gas markets) have centralised risk management where market participants must provide security to at least cover their fees plus their expected exposure (which depends on their market activity). Market participants have a trading limit set at a percentage of their security (85% in the DWGM and STTM, 100% in the Gas Supply Hub) to cover activity in the interval between incurring the exposure and completion of monitoring activities.

A market participant's exposure at any time includes settlement amounts in the current month, settlement amounts in previous months that have not yet been settled, and revised settlement amounts for previous months that have not yet been settled. Provided a market participant's total exposure is less than their trading limit, no action need to be taken (although warning notices may be issued).

If a margin call is issued to a market participant in the DWGM or STTM, it has limited time to either make a cash prepayment or to increase its security. A failure to do so results in its security being called on, and suspension from the market until it has have made full payment.

If the security is unable to cover the extent of a market participant's exposure, in the DWGM or STTM, payments to all market participants receiving payments are reduced to cover the shortfall.

Where a market participant's exposure exceeds trading limits in the Gas Supply Hub, it is unable to enter new orders, facing a trading halt and a margin call.

5.3.2 Minimum security limits

Minimum security limits for market participants could be set by the operator using statistical analysis of past results. This gives a limit that may be appropriate for the market participant provided their past behaviour is similar to their future market behaviour. Alternatively, the limit could be set by market participants taking their planned market activity into account, and knowing that they face frequent warnings and margin calls if the limit is too low.

The Southern Hub will feature exchange based trading, so it is important that there is real time assessment of participants' ability to settle the trade. This would give an added incentive for market participants to ensure that they have sufficient security to

90 Operator fees excepted.

trade at the Southern Hub. There is also an incentive to balance the cost of providing security with the costs of managing frequent margin calls.

The Commission suggests that the operator sets a minimum level of security to cover expected fees, and that market participants are responsible for setting their own security limit above the minimum level. The GMRG should consider the percentage of the security that is available as a trading limit.

5.3.3 Prudential assessments

In all gas markets operated by AEMO, prudential exposure of each market participant is assessed at least on a daily basis using the most recently available data. This can mean delays in conducting prudential assessments (particularly in the DWGM as initial metering data is not available for three business days). This delay affects the percentage of security available as a trading limit – the longer the delay, the lower the percentage.

In the DWGM and STTM it is not practicable to conduct prudential assessments as market participants submit bid and offers – there is no certainty as to which bids will be scheduled. The Gas Supply Hub trading platform checks a market participant’s order submissions for the potential of their exposure to exceed their trading limit if the order is transacted, and would prevent the trade from proceeding.

The Commission suggests that the prudential exposure of market participants at the Southern Hub should be assessed at least daily, potentially with real time validation of trades and capacity purchases before transactions are confirmed.

The daily assessment would identify a market participant's exposure at the time of the assessment, and would trigger a margin call if the participant had exceeded its operating trading limit. A real time assessment of trades and capacity purchases would cover any changes in exposure since the daily assessment, including imbalance charges, plus the exposure impact of the trade/purchase being checked in real time. As it may be undesirable to limit a participant's ability to trade under margin call (as this might risk it incurring greater imbalance costs), it may be preferable to continue to allow exchange trading to a higher exchange trading limit than the operating trading limit, but below the security provided.

6 Institutional roles

The implementation of the Southern Hub model would be unlikely to cause significant changes to the statutory functions of AEMO, APA and the AER as set out in the National Gas Law. Nevertheless, it would cause a number of modifications to the roles of these parties and market participants under the National Gas Rules.

This chapter provides an overview of the current allocation of roles between these institutions and market participants in the DWGM, and describes the changes to these roles that would arise as a consequence of the introduction of the Southern Hub model. The chapter also provides the Commission's assessment of the appropriate institutions to undertake these roles.

6.1 Current institutional arrangements in Victoria

As described in chapter 2 of the Draft Final Report[91], the DWGM can be considered to integrate three functions into one:

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

Consequently, AEMO, which operates and administers the DWGM has a number of roles:

- it administers the trading of gas through the DWGM's bidding and settlement process;
- it balances the system by buying or selling gas in order to manage linepack variations with the intention of meeting an end of day linepack target;
- it allocates capacity on the basis of DWGM outcomes, through market carriage arrangements; and
- it acts as system operator, scheduling gas through the DWGM. As such, it is responsible for the control, operation, safety, security and reliability of the DTS.

APA owns, builds and maintains the DTS and makes it available to AEMO to enable it to fulfil the roles listed above. The terms on which APA makes the DTS available to AEMO are set out in the Service Envelope Agreement (SEA),[92]which also defines the

91 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Final Report, October 2016.

92 Section 91BE of the National Gas Law requires the service provider for a DTS to have in place an agreement with AEMO for the control, operation, safety, security and reliability of the DTS.

transportation capacity of the DTS[93] and APA's and AEMO's obligations in relation to the delivery of the agreed capacity.[94]

Under the Service Envelope Agreement, APA provides a single pipeline service, the Tariffed Transmission Service, which is the Reference Service for the purposes of the economic regulatory provisions in Parts 8-12 of the National Gas Rules. This service is provided to AEMO, which is the only 'user' of the pipeline for the purposes of the National Gas Law. Market participants in the DWGM can access the Reference Service if they are a registered participant, and obtain access through the daily DWGM bidding process. The only direct relationship between APA and a market participant is through a Transmission Payment Deed, which requires the market participant to pay transportation charges directly to the pipeline operator.

The DTS is a covered pipeline, subject to economic regulation by the AER under Parts 8-12 of the National Gas Rules. APA is required to submit an Access Arrangement proposal to the AER, which is then responsible for approving the pipeline operator's revenue requirement, capital expenditure, reference tariffs and non-price terms and conditions of access for the Access Arrangement period.

6.2 Institutional arrangements in the Southern Hub

The Southern Hub represents a substantial change to the current DWGM arrangements. However, while some institutional roles would be modified as a result of the implementation of the Southern Hub, there are no completely new roles that are created.

Table 6.1 gives an overview of the allocation of institutional roles, to the extent the roles would be modified in the Southern Hub model.

93 In respect of capacity, AEMO and APA are required to maintain an agreed common system model that is used, among other things, to determine the system's capacity. This is important for a number of reasons including: determining the impact of planned and unplanned pipeline or plant outages on system capacity; determining the additional pipeline capacity created by pipeline expansions/augmentations for the allocation of AMDQ cc by APA; and providing information to the market and regulators on potential future pipeline constraints for future investment and approval of regulated investment.

94 In respect of each party's obligations, the Service Envelope Agreement requires APA to provide AEMO not only the agreed transmission system capacity, but also a range of supporting services. It further requires AEMO to observe good practice in operating the system and not operate facilities in a manner that will materially adversely affect APA's ability to comply with its obligations under the Service Envelope Agreement.

Table 6.1 Overview of institutional roles in the Southern Hub model

Role	AEMO	APA	AER	Market participants
Exchange operator	✓			
Notification of trades				✓
System operator, including: • residual balancing; • determining above baseline capacity amount; and • allocating existing capacity.	✓			
Primary balancing				✓
Nominations				✓
DTS service provider		✓		
Baseline capacity amount: • Proposing baseline capacity amount • Approving baseline capacity amount		 ✓ 	 ✓	
Approving reserve price for baseline capacity and reference tariff for distribution connected exit points			✓	
New capacity: • Conducting open season for new capacity • Conducting detailed planning studies for new capacity • Approving price steps for possible capacity expansions • Conducting integrated auction • Proposing capacity expansions informed by auction results • Approving capacity expansions informed by auction results	 ✓ 	 ✓ ✓ ✓ 	 ✓ ✓	

As a guiding principle, where a change in the allocation of roles between institutions is not necessary to implement the Southern Hub model, the Commission has sought to allocate roles consistent with the current arrangements and retain the existing legal and regulatory architecture. The likely benefits of this approach are that it may:

- be easier and quicker to design and enact (through changes to the National Gas Rules National Gas Law) the implementation of the Southern Hub;
- reduce the risk of any unintended consequences arising from making multiple complex changes; and
- allow the roles to be carried out more successfully, particularly immediately after the introduction of the Southern Hub model, because the roles (albeit modified) would be allocated to institutions with existing experience.

In light of this guiding principle, the recommended allocation of roles in the Southern Hub is described below, with any additional rationale provided where appropriate.

6.2.1 Roles relating to commodity trading

Commodity trading would be administered by AEMO as the *exchange operator*. While the nature of trading would be considerably different in the Southern Hub compared to now, as with the current DWGM, AEMO (as the exchange operator) would be responsible for matching bids with offers, and facilitating the settlement process.

Other organisations might alternatively be able to undertake the exchange operator role, such as the ASX. However, this would be inconsistent with existing institutional arrangements. Furthermore, there may be benefits from AEMO operating the Southern Hub exchange because it is the organisation that will operate the Northern Hub exchange - potentially reducing transaction costs and complexity for market participants and supporting the introduction of common back-end system, registrations processes, prudential requirements and other features, as discussed in section 2.2.3.

As market participants would not be required to undertake all of their trades on the exchange (e.g. they could enter into bilateral trades at the Southern Hub), they would be required to inform the system operator upon entering into such trades, so that the system operator could calculate market participants' imbalance positions for the purpose of allocating residual balancing action costs.

6.2.2 Roles relating to balancing and system security

Consistent with the current arrangements, AEMO would retain its role as *system operator*, responsible for safely and reliably delivering nominations made by market participants across the DTS.

Under the Southern Hub model, market participants would have a far more substantial role in balancing the DTS, bestowed through financial incentives to keep in individual balance (at those specific times when system security is threatened). AEMO (as the system operator) would facilitate market participants' balancing actions, for example specifying and informing market participants of the residual balancing bands, the system balancing signal, their individual positions, and residual balancing action undertaken.

AEMO (as the system operator), would have a residual balancer role, buying and selling gas on the exchange only when required to keep the system as a whole in reasonable balance if market participants did not collectively do so. AEMO would also be responsible for administering settlement of any residual balancing action taken.

In addition to its residual balancer role, AEMO (as the system operator) would be responsible for system security more generally (i.e. not specifically related to system wide linepack issues). It would execute this role through a number of actions, for example buying or selling gas at specific locations, or buying back capacity rights, to address local system security issues. AEMO (as the system operator) would also be able to invoke emergency management procedures and direct market participants in order to maintain system security. Market participants would be required to follow directions given to them by AEMO as system operator.

Market participants would be required to nominate their injections and withdrawals to AEMO (as the system operator), so that it could manage flows on the system and calculate market participants' imbalance positions. Market participants' nominations would be validated against their capacity holdings by AEMO (as the system operator).

6.2.3 Roles related to pipeline capacity

Ownership and construction of DTS

Institutional arrangements regarding owning, building and maintaining the DTS would be unaffected by the introduction of the Southern Hub model. APA would continue to fill these roles as *DTS service provider*. APA (as the DTS service provider) would continue to make the DTS available to AEMO (as the system operator) to operate in accordance with the Service Envelope Agreement. APA (as the DTS service provider) would provide the Tariffed Transmission Service to AEMO (as the system operator), which would remain the only user of the DTS for the purposes of the National Gas Law.

Calculating the amount of existing capacity to be released

Unlike the current arrangements where the capacity of the DTS is agreed between AEMO and APA under the terms of the Service Envelope Agreement, the level of capacity which APA (as the DTS service provider) would be obligated to make available to AEMO (as the system operator) would be determined as part of a process whereby APA would propose, and the AER would approve the level of baseline capacity to make available at each entry and exit point (or zone) on the DTS.

Absent of this process, the DTS service provider may choose to release less capacity than is efficient (in order to reduce its costs to make baseline capacity available, and reduce its liabilities for failing to do so), depending on its financial incentives. In addition, the level of baseline capacity should be set through a process that is transparent and in which stakeholders have the opportunity to participate.

The Commission considers that approving the baseline level of capacity is consistent with the AER's economic regulatory function under the National Gas Law. The AER is the most appropriate body to carry it out given the linkages to the Access Arrangement review (see section 4.2). It is also worth noting that economic regulators in other countries where the entry-exit system has been implemented are also responsible for approving the baseline capacity levels.

AEMO (as the system operator) would be responsible for identifying whether, and calculating how much, additional capacity above the baseline is available at entry and exit points on a short-term basis. As system operator, AEMO would have the best knowledge of about daily gas flows, capacity, linepack and other relevant factors in order to make this calculation. In the event the sale of additional capacity leads to constraints on the day (that is, more capacity being nominated for use by market participants than can be delivered), the interruptible nature of the capacity would provide AEMO with the ability to curtail those rights in order to manage the congestion.[95]

Allocating existing capacity

As the system operator, AEMO would retain responsibility for releasing to market participants the capacity that has been made available to it by APA (as the DTS service provider). However, instead of dynamically allocating capacity through the market carriage arrangements, it would instead be allocated through auctions administered by AEMO for baseline, above baseline and contracted but un-nominated capacity.[96]

The AER would be responsible for approving the reserve price for baseline capacity released through the auction and the reference tariff for distribution connected exit points (or zones).[97]

Payments by market participants for baseline capacity would continue to be made directly to APA (as the DTS service provider). This would continue to be the only direct relationship between market participants and APA (as the DTS service provider).

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95 In EU gas markets, the entities that build and allocate capacity, manage congestion and undertake balancing, tend to be integrated, for-profit private or state-owned organisations. Many operate under an incentive regime aimed at co-optimising capacity release and system operation. In Victoria, the ability to achieve a similar outcome is restricted by AEMO's not-for-profit status, which prevents the use of financial incentives, and the separation of APA as the pipeline owner and AEMO as the system operator.

96 Other than for distribution connected exit capacity, which would be automatically allocated.

In the Southern Hub model, capacity would also be able to be reallocated between market participants, facilitated by a secondary capacity trading exchange. As with the commodity exchange, this role could be performed by a variety of institutions, such as the ASX. However, there may be benefits from having the secondary capacity exchange run by the same organisation that is releasing primary capacity and operating the commodity exchange (i.e. AEMO as the system operator and the exchange operator, respectively). Implementation costs may be lower, and market participants would be able to obtain their commodity and capacity (through a variety of primary and secondary capacity markets) from the same organisation, facilitating the coordination of capacity and commodity trading. The Gas Market Reform Group should consider further the appropriate institution to operate the secondary capacity trading platform, including the scope for a competitive process to allocate this function.

New capacity

The hybrid open season approach for assessing new capacity expansions is described in section 4.5. The rationale for the institutional arrangements for that process are as follows:

- APA (as DTS service provider) would engage market participants as part of the open season process to ascertain their likely willingness to underwrite potential capacity expansions. APA would be best placed to undertake this work as it would have the best understanding of potential expansions and related costs. It is also consistent with its current role of gathering information to inform any proposed capital expenditure as part of its Access Arrangement. Preferably, this stage would be conducted shortly after the release of AEMO's Victorian Gas Planning Report, so that APA and market participants would be as informed as possible.

- If the open season process revealed to APA that there was likely to be demand for a capacity expansion(s), it would then undertake detailed planning of a range of potential capacity expansions and their associated costs. On this basis, it would develop the price steps associated with the expansion options for the relevant entry and/or exit points, and propose these to the AER. Again, APA (as DTS service provider) has the best information to undertake this work.

- The AER would consult with interested parties and determine whether or not to approve the proposed price steps (which would become the new reference tariffs if any of the expansions proceed) having regard to the relevant tests and principles in the National Gas Rules. This is consistent with the AER's current economic regulatory function.

- AEMO (as system operator) would conduct the integrated auction, based on the additional capacity that would be available at each price step, as approved by the AER. It is appropriate for AEMO (as system operator) to undertake this function

97 Above baseline capacity and capacity released through the auction of contracted but un-nominated capacity would have a reserve price of zero and so would not need to be calculated by the AER.

because the integrated auction would also be used to allocate some existing baseline capacity not already sold (a task allocated to AEMO (as system operator) for reasons discussed above).

- The remainder of the process would then be consistent with existing arrangements, other than that APA (as DTS service provider) and the AER would have the results of the integrated auction to inform their proposals for, and approvals of, prudent capital expenditure.

Abbreviations

ACCC	Australia Competition and Consumer Commission
ACER	Agency for the Cooperation of Energy Regulators
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
APA	APA GasNet
ASX	Australian Securities Exchange
CFO	call-for-order
COAG	Council of Australian Governments
Commission	See AEMC
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EU	European Union
FCFS	first-come-first-served
GMRG	Gas Market Reform Group
GSA	gas supply agreement
GSH	Gas Supply Hub
LNG	liquified natural gas
MDQ	maximum daily quantity
MHQ	maximum hourly quantity

MP	market participant
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NRT	near real time
NTS	National Transmission System
Ofgem	Office of Gas and Electricity Markets
OTC	over-the-counter
PARCA	Planning and Advanced Reservation of Capacity Agreement
POS	position
QNI	Queensland – New South Wales Interconnector
RBA	residual balancing action
RBB	residual balancing bands
SBS	System Balancing Signal
SCO	Senior Committee of Officials
SEA	Service Envelope Agreement
SEA Gas	South East Australia Gas Pipeline
SRMC	short-run marginal cost
STTM	Short Term Trading Market
UAFG	unaccounted for gas
UIOLI	use-it-or-lose-it