Gas Market Scoping Study

A report for the AEMC

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K LOWE
CONSULTING

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The study and our findings are subject to various assumptions and limitations referred to within the report. It draws heavily on information and views provided by stakeholders in meetings conducted during May and June 2013. Though supplied in good faith and reflecting the knowledge, expertise and experience of the consultants involved, we caution that this study has been conducted in a relatively short time period, allowing for limited independent analysis of the issues raised. Some issues, notably emergency management, have been addressed only at a very high level. Significant further work would be required before drawing clear conclusions.

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Glossary

ACQ	Annual Contract Quantity
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity and AMDQ credit certificates
BB	Bulletin Board
CBP	Cheepie to Barcaldine Pipeline (Qld)
CGP	Carpentaria Gas Pipeline (Qld)
CRP	Central Ranges Pipeline (NSW)
CWP	Central West Pipeline (NSW)
DSDBI	Victorian Department of State Development, Business and Innovation
DTS	Declared Transmission System (Vic)
CSM	Coal Seam Methane
DWGM	Victorian Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline (NSW/ACT)
ETS	Emissions Trading Scheme
GJ	Gigajoule (1,000,000,000 joules)
GMLG	Gas Market Leaders Group
GSOO	Gas Statement of Opportunities
MAPS	Moomba to Adelaide Pipeline (SA)
MCE	Ministerial Council on Energy
MDQ	Maximum Daily Quantity
MHQ	Maximum Hourly Quantity
MOS	Market Operator Service
MP	Market Participant
MSP	Moomba to Sydney Pipeline (NSW/ACT)
Mtpa	million tonnes per annum
NEM	National Electricity Market
NGERAC	National Gas Emergency Response Advisory Committee
NGL	National Gas Law
NGR	National Gas Rules
PJ	Petajoule (1,000,000 Gigajoules)
QSN Link	Queensland South Australia New South Wales Link (Qld)
RBP	Roma to Brisbane Pipeline (Qld)
SCER	Standing Council on Energy and Resources
SME	Small to medium commercial and industrial customers
STTM	Short Term Trading Market
SWP	South West Pipeline (Vic)
SWQP	South West Queensland Pipeline (Qld)
TGP	Tasmanian Gas Pipeline (Tas)
TJ	Terajoule (1,000 Gigajoules)

Executive Summary

As part of the Strategic Priorities for Energy Market Development 2013 Review, the Australian Energy Market Commission (AEMC) announced that it would be undertaking a gas market scoping study in the first half of 2013,[1] the purpose of which would be to:

- review, at a high level, the regulatory and market arrangements applying to the supply of gas from the time it enters a transmission pipeline to the time it is delivered to end-users;
- engage with stakeholders to get a better understanding of how well they think the current arrangements are working and their perspectives on any improvements that could be made, which would better promote the National Gas Objective (NGO);
- identify areas of potential improvement in the current regulatory and market arrangements that could promote efficiency in the long term interests of consumers and that may benefit from more detailed market development work; and
- better understand the strategic framework and direction of the gas market to inform its consideration of how individual rule changes contribute to that direction.

While it is clear that a study of this nature will not address the more fundamental supply-side issues currently affecting the eastern Australian gas market, the AEMC is of the view that the regulatory and market arrangements still have an important role to play in promoting the efficient allocation of gas and efficient investment in, operation and use of, all aspects of the gas supply chain. The AEMC therefore considers it worthwhile during this period of structural change, to stand back and take stock of the current arrangements and consider the extent to which they are promoting the NGO and are likely to continue to do so in the future.

To assist with its consideration of these issues, the AEMC has asked K Lowe Consulting (KLC) to prepare a report that:

Part A. provides a comprehensive overview of the state of the eastern Australian gas market and the regulatory and market arrangements applying to the supply of gas from the time it enters a gas transmission pipeline to the time it is delivered to end-users; and

Part B. identifies whether there are any areas of the existing market and regulatory arrangements that may benefit from future market development work, prioritises their importance and identifies who is best placed to take it forward (ie, the Standing Council on Energy Resources (SCER), the AEMC, the Australian Energy Market Operator (AEMO), industry or individual market participants).

The AEMC has also asked Farrier Swier Consulting to peer review Part B.

The key recommendations arising from the study are summarised in Table E.1.

[1] AEMC 2013, Strategic Priorities for Energy Market Development 2013 Discussion Paper, p. 41.

Table E.1: Summary of recommendations

<table>
<tr><th>Recommendation</th><th>Responsibility</th><th>Timing</th></tr>
<tr><td colspan="3">High Priority</td></tr>
<tr><td colspan="3">Strategic direction for future gas market development in eastern Australia</td></tr>
<tr><td>Undertake a strategic review that considers both:
▪ the direction that the eastern Australia gas market should take over the next 10-15 years, if it is to make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports: the efficient allocation of gas and transportation capacity in the short, medium and longer-term; the efficient trade and movement of gas between jurisdictions; efficient and timely investment in upstream production and transportation capacity; the efficient allocation of risks; and the development of financial markets that can be used by participants to hedge risks. As part of this assessment, consider would ideally be given to whether the existing facilitated markets (ie, the DWGM and STTM) are meeting their stated objectives in the most efficient manner and, if not, how this could be addressed; and
▪ the principles that should guide the development and design of facilitated markets in the future.
A review of this nature is consistent with both SCER's gas market policy principle of 'promoting market development' and its policy objective of increasing the role of market to: ensure the most efficient allocation of gas resources and infrastructure; and increase market flexibility.</td><td>SCER to sponsor review.
AEMC to carry out review.</td><td>2013-14</td></tr>
<tr><td colspan="3">Detailed review of the design of the STTM and certain elements of the DWGM</td></tr>
<tr><td>Undertake a detailed review of the design of the STTM and particular design elements of the DWGM and determine whether improvements can be made to the existing design that would better promote the NGO.</td><td>AEMC and SCER to jointly draft terms of reference.
SCER to determine whether the AEMC and/or AEMO should carry out the review once scope of work defined.</td><td>2013-14</td></tr>
<tr><td colspan="3">Medium Priority</td></tr>
<tr><td colspan="3">Time taken for STTM and DWGM rule changes</td></tr>
<tr><td>Investigate ways of reducing the time taken to develop and implement STTM and DWGM rule changes and streamline the consultation process.</td><td>AEMO and AEMC.</td><td>2nd half 2013</td></tr>
<tr><td colspan="3">Improved investment under the Victorian market carriage model</td></tr>
<tr><td>The two review options (which are not mutually exclusive) that could be taken to promote improved investment outcomes in the Victorian Declared Transmission System (DTS) are:
Option 1: Undertake a holistic review of the regulatory investment process and application of this process in Victoria; and/or
Option 2: Undertake a preliminary internal review on the prospects for introducing tradable transmission rights and proceed to a more detailed public review if tradable transmission rights are considered likely to provide improved investment signals in the DTS.
Of the two options, we would at this stage recommend commencing work on Option 1 and the internal review under Option 2, but only proceeding to the detailed public review under Option 2 if the internal review reveals it is likely to be beneficial to implement tradable transmission rights.</td><td>SCER to sponsor the review.
AEMC to carry out review.</td><td>2014-15</td></tr>
</table>

Recommendation	Responsibility	Timing
Capacity trading under the contract carriage model		
Consideration to be given to how to reduce search, transaction and co-ordination costs associated with spot or very short term capacity trades (ie, capacity trades for periods less than one month) to facilitate this form of capacity trading by shippers. For longer term trades (eg, monthly, seasonal or longer term transactions), it would appear that shippers and pipeline owners have the appropriate incentive and ability to sell unutilised contracted capacity and that transaction and co-ordination costs are unlikely to act as an impediment to such trade. There does not therefore appear to be any failure in this segment of the market that would require the introduction of a regulatory measure to encourage a greater level of this type of trading.	Industry led.	2013-14
Low Priority		
Greater interaction with the NEM		
Assessment of whether greater consistency between market parameters in the NEM and imbalance markets to be carried out as part of the STTM and DWGM design review.	AEMC and/or AEMO depending on allocation of responsibility for review.	2013-14
If there is a significant change in climate change polices and/or conditions in the NEM that supports gas fired generation, then a more detailed review could be undertaken to get a better understanding of the interactions between the two markets and to ensure existing arrangements are fit for purpose.	SCER to sponsor review. AEMC to carry out review.	n/a
Retail markets		
Be cognisant of the potential for higher wholesale gas prices to prompt jurisdictions to implement a cap on retail prices that is lower than the efficient cost of supply. If there is any indication this may occur, liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition.	AEMC.	2015-2018
Information		
Consider whether any additional operators should be designated Bulletin Board facility operators. Consider whether improvements can be made to the quality and accessibility of existing STTM, DWGM and Bulletin Board data.	AEMO	2nd half 2013 or 2014
Other		
DWGM rule change proponents		
Refer stakeholder comments on the effect of the restriction set out in section 295(3)(a) of the NGL on DWGM related rule changes to the Victorian Department of State Development, Business and Innovation (DSDBI) and allow it to consider whether there is still a rationale for having this restriction and, if so, whether any improvements could be made to the current process.	AEMC to refer to Victorian DSDBI.	2nd half 2013
Emergency Arrangements		
Refer stakeholder comments on emergency arrangements and our high level observations about the need: to improve the transparency and accessibility of these arrangements; formalise the obligations industry have to provide information in emergencies; review jurisdictional curtailment tables; and consider whether such tables should be publicly available to SCER and the Commonwealth Department of Resources, Energy and Tourism (DRET), as chair of the National Gas Emergency Response Advisory Committee (NGERAC).	AEMC to refer to SCER and DRET.	2nd half 2013

Further detail on scoping study's findings, the context in which the study is being undertaken, the assessment framework used in the study and the issues raised by stakeholders during the consultation process, is provided below.

Context in which the scoping study is being undertaken

The scoping study is being carried out at a time when the eastern Australian gas market is undergoing a number of fundamental demand- and supply-side changes, the most significant of which are being driven by the development of LNG facilities in Queensland.

The influence the LNG developments are having on the market is not surprising given both the scale of the projects under construction (25.3 mtpa or~1,550 PJ pa)[2] and the relatively short period of time over which the projects are to become operational (late 2014-2015). With production in eastern Australia having to treble over the next three to five years to satisfy both domestic and LNG export demand, and some LNG proponents having to supplement their own production with supply from other sources, conditions in the market are understandably quite tight at the moment with only a limited number of producers in a position to sell gas under medium to longer term contracts. The effect of these tight conditions on prices is already being felt, with prices under a number of new contracts being reportedly either linked to an international oil price benchmark or at level consistent with LNG netback[3] prices.[4]

Looking forward, conditions are expected to continue to tighten when the LNG facilities come on line and start ramping up to full capacity (2015-2018), because the period over which this is to occur, coincides with the expiry of a large number of domestic gas supply contracts.[5] The market is therefore likely to be placed under additional pressure over the next three to five years as domestic customers compete with each other, and potentially LNG proponents, to secure supply from a much smaller set of producers.

Whether or not there will be sufficient gas available to domestic customers during this period is another question. Although there are sufficient reserves in eastern Australia to supply the domestic market for some years to come, the critical question currently facing the market is whether domestic oriented production will be able to expand rapidly enough to address the supply shortfall that is expected to arise once the LNG projects start exporting and domestic contracts expire (2015 onward).

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2 This estimate includes a 10% fuel allowance.

3 The term 'LNG netback price' is used to describe the equivalent price a producer could receive at a particular location if it was to export gas to an LNG customer, once the costs of transportation, shipping and liquefaction costs are taken into account.

4 See for example, Infratil Ltd, Lumo Energy signs gas sales agreement, 14 May 2013 and The Australian, Origin Energy secures record gas price, 21 December 2012.

5 See for example, Queensland Department of Energy and Water Supply, 2012 Gas Market Review, p.23, AGL, Macquarie Australia Conference, 2 May 2013, slide 14, SKM, Gas Market Modelling for the Queensland 2011 Gas Market Review, 29 July 2011, p.93 and BREE, Gas Market Report, July 2012.

While it is possible that production from existing sources in eastern Australia could increase,[6] the gap that will be left as a result of the LNG developments is such that new sources of supply will need to come on line in this period. A number of new sources of supply have been proposed, including the Kipper field in the Gippsland Basin, the Gunnedah Basin, the Gloucester Basin, the Ironbark field in the Bowen/Surat Basin, unconventional sources in the Cooper Basin, and the South Nicholson and Isa Super Basins in Northern Territory and north-west Queensland. It is unclear at this stage though whether all of the proposed projects will proceed and if they do, whether they will be used to supply the domestic or export market.

The other key uncertainty is whether projects that pass the final investment decision stage will be able to be brought on rapidly enough to fill the gap in the domestic market that is expected to emerge from 2015. Given that a number of the projects are still in the exploration stage and will require the development of new production facilities and/or new transmission pipelines, it appears unlikely that gas from these sources will be available to the market by 2015.[7] It is not therefore surprising that conditions in the market are expected to become even tighter from 2015,[8] or that some market commentators, such as EnergyQuest, are projecting a supply shortfall to emerge around this time.[9]

Another important point to bear in mind with these potential new sources of supply is that bringing them on line will require a significant investment in upstream facilities and, in some cases, new transmission pipelines. The development of these new sources of supply is therefore likely to be underwritten by long term foundation contracts. Medium to longer term contracts (ie, contracts with a term of three or more years) are therefore likely to remain the predominant form of contracting for some time to come in the eastern Australian gas market. While on this topic, it is worth noting that in a number of the discussions held with stakeholders, reference was made to the relevance of international markets, such as the Henry Hub in the US and European markets. The one common observation made by stakeholders is that these markets have taken a considerable amount of time to evolve and it is therefore unlikely that the eastern Australian gas market will move rapidly away from medium to longer term contracts to spot and futures trading.

A further source of uncertainty currently affecting the market and, in particular, gas fired generators, is whether a carbon emissions scheme will continue to exist after the federal election and, if so, what path carbon permit prices will take. In addition to this uncertainty, gas fired generators are having to grapple with the adverse effects of subdued growth in the demand for electricity in the National Electricity Market (NEM), the continued expansion of renewable energy sources, the cessation of the Queensland Government's Gas Scheme and higher gas prices.

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6 For example, if the Gippsland Basin Joint Venture was able to reduce its commitment to meet peak demand in winter (ie, by entering into contracts with lower load factors), it could increase output over the remainder of the year.

7 Note that this observation is consistent with the potential start dates identified by project proponents – see Table 4.2.

8 See for example, BREE, Gas Market Report, July 2012, p.45 and Queensland Department of Energy and Water Supply, 2012 Queensland Gas Market Review, pxi.

9 EnergyQuest, EnergyQuarterly, May 2013, p25. See also AFR, Dim future for gas supply, 27 May 2013.

As the preceding discussion highlights, the eastern Australian gas market is currently undergoing a number of fundamental changes. The precise effect that these changes will have on the market is at this point unclear, given the uncertainties currently surrounding when new sources of supply will be brought on line and the future for climate change policies. However, there is a general perception in the market that the following will occur:

- Conditions in the market will continue to tighten in the short to medium term as the LNG projects ramp up (late 2014-2018) and a large number of domestic gas supply contracts expire, with the effects of this tightness being felt most acutely in Queensland.
- New sources of supply will be required to fill the void left by the LNG developments, but in the interim more gas from Victoria is likely to be supplied into NSW, the ACT, South Australia and, potentially Queensland.
- Gas prices across eastern Australia will converge toward the LNG netback level (with prices either linked to an international oil price benchmark or set at an equivalent level) as existing contracts roll off and new contracts are entered into. The development of new sources of supply is unlikely to result in gas prices falling back to historic levels of $3-$4/GJ,[10] because these sources are expected to incur higher production costs than existing sources of supply. [11]
- The demand for gas by generators will fall in the short to medium term and no new gas fired generation investment will be required for some time unless conditions in the NEM change materially, or there is a change in climate change policy settings.

Viewed in this way, it is apparent that the changes currently underway could have a significant effect on the movement and/or trade of gas in eastern Australia over the short to medium term and, in doing so, test the robustness of the current regulatory and market arrangements applying to the supply of gas from the time it enters a transmission pipeline to when it is delivered to end-users (see Box E.1). These changes therefore provide important context for the study.

[10] AER, State of the Energy Market, 2012, p.94.

[11] Santos has also indicated that the development of shale gas is only likely to proceed if ex-plant gas prices in eastern Australia rise from their current levels of $3-$4/GJ to about $6/GJ. *See* The Australian, Gas price rise prompts Santos to revamp Cooper Basin, 23 May 2011.

Box E.1: How the changes underway *may* test the current arrangements

Based on our review of the changes underway, it would appear the changes *may* in the short to medium term:[1]

- test the degree of interoperability between the Victorian market carriage and contract carriage models, given the potential for more gas to be exported from Victoria into the remainder of south eastern Australia;
- have a material effect on the utilisation of some pipelines, which could:
  - result in the capacity of those pipelines experiencing a substantial reduction in utilisation becoming partially redundant; or
  - require significant investment on pipelines experiencing higher utilisation.

  These effects could be transitory or permanent and so to the extent the effects are felt by regulated pipelines, regulators would need to carefully consider how to use particular rules in the National Gas Rules (NGR), such as the new facilities investment and redundant asset provisions;
- result in a greater degree of volatility in the Adelaide Short Term Trading Market (STTM) and, to a lesser extent the Victorian Declared Wholesale Gas Market (DWGM), given the amount of new renewable generation forecast in these locations and the increased reliance that may be placed on gas fired generation to act as back-up generation;
- adversely affect retail competition if policy makers respond to higher gas prices by imposing a cap on retail prices that doesn't allow efficient costs to be recovered; and/or
- test the emergency arrangements in the future, given the potential for:
  - south eastern Australia to become more reliant on gas from Victoria until new sources of supply are brought on line and therefore more exposed to any emergencies that may originate in this state (ie, because there is less diversity of supply); and
  - emergencies affecting the supply of gas from the Cooper or Bowen/Surat basins to require gas to be apportioned between export and domestic customers.

1. The term 'may' is used because it is not possible to determine precisely how all of these changes will affect the market.

At the same time that the gas market scoping study is being carried out, a number of other reviews are being undertaken, such as:

- the Department of Resources, Energy and Tourism (DRET) and Bureau of Resources and Energy Economics (BREE) review of eastern Australia's demand-supply situation;[12]
- the Peter Reith Victorian Gas Task Force, which was formed by the Victorian Government in early 2013 to examine gas supply and pricing issues; and
- the NSW Legislative Assembly's inquiry into downstream gas supply and availability in NSW, which commenced in April 2013 and is currently in the consultation phase.

Work is also being carried out by the Australian Energy Market Operator (AEMO) on the development of the Wallumbilla gas supply hub and the Standing Council on Energy and Resources (SCER) on gas transmission pipeline capacity trading. The scoping study may therefore be viewed as complementing the work being carried out by each of these parties.

Assessment framework employed in the scoping study

The purpose of the scoping study is, as noted previously, to:

- undertake a high level review of the regulatory and market arrangements applying from the time gas enters a transmission pipeline until it is delivered to end-users; and
- identify whether there are any specific areas of the existing market and regulatory arrangements that may benefit from further investigation or market development work.

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12 Minister for Resources, Energy and Tourism, Media Release – Lifting the lid on Australia's gas markets, 27 May 2013.

Importantly, the task at this stage is *not* to identify solutions to identified issues. Rather, the task at this stage is to identify whether there are any issues with the current arrangements, assess their materiality and identify who may be best placed to take them forward. This study has therefore focused on the first three steps of the following assessment framework:

Step 1: Carry out a high level review of the current regulatory and market arrangements and consider whether there are any particular areas of these arrangements that may benefit from further investigation and/or market development work having regard to the NGO and the principles set out in SCER's Gas Market Development Plan, which are to: [13]

- promote market development; and
- ensure that supply responds flexibly to market conditions.

Step 2: Assess the materiality of the issues identified in step 1.

Step 3: For those issues that are considered material, identify options for how the issues could be progressed and who may be best placed to take them forward (ie, SCER, the AEMC, AEMO, industry or individual market participants). Also consider the priority that should be accorded to the issue.

Step 4: Carry out a detailed review of the issues identified in step 3, determine whether there is a case for action (eg, there is a market failure or deficiencies in the existing legislative/regulatory framework) and, if so, identify the set of feasible solutions (regulatory, self-regulatory, co-regulatory and non-regulatory), having regard to the NGO, the characteristics of the market, input from stakeholders and whether the solutions are targeted and proportionate to the issue they are intended to address.

Step 5: Carry out a transparent cost benefit assessment and implement the feasible solution if the benefits are judged to outweigh the costs and it is consistent with the NGO.

Stakeholder engagement

Stakeholder engagement has been a key element of the scoping study and has been conducted through a stakeholder workshop, which was held on 31 May 2013, a series of one-on-one meetings with over 20 stakeholders and a written submission process.[14] Table E.2 provides an overview of the issues raised by stakeholders on each of these issues. We should caution that in the time available it has not been possible to validate or otherwise test all of the claims made by stakeholders. The information contained in this table is therefore based on what stakeholders have reported and should be treated accordingly.

13 SCER, Gas Market Development Plan, December 2012.

14 Written submissions were received from Alinta Energy, AEMO, APA, Australian Pipeline Industry Association, Energy Action, the Energy Users Association of Australia, GDF Suez and Origin Energy.

Table E.2: Summary of stakeholder comments

Topic		Comments
Gas market development		Gas market development over the last 2-3 years has been ad-hoc and without a clear strategic direction. To the extent further reforms are required (ie, because there is a clear market failure), a more strategic, transparent and measured approach should be employed and industry should be closely consulted. Stakeholders would prefer a greater degree of institutional separation between the roles of market developer and market operator when future market developments are being assessed. International gas markets, such as the Henry Hub in the US and European markets, have all taken time to evolve and so it is unlikely that the Australian market would move rapidly away from medium-long term contracts to spot and futures trading.
Victorian market carriage model		In general stakeholders recognise that this model has a number of positive attributes but concerns have been raised about the timeliness and efficiency of investment in the DTS and the difficulties some have experienced in the past exporting gas via the DTS.
Contract carriage model		There is a general perception that investment in contract carriage pipelines has been timely and efficient. Stakeholders were also of the opinion that there is no need for regulatory intervention to encourage capacity trading or sales of 'as available services'. Some stakeholders have suggested though that search costs could be reduced if shippers' contact details were available in a central location and information on the availability of spare capacity was more readily accessible. Shippers on the RBP have stated it can be difficult to trade capacity on the pipeline because of the technical characteristics of the pipeline (ie, multiple injection/withdrawal points) and the manner in which services are sold (ie, between specific injection and withdrawal points).
Regulation of gas pipelines		In general, stakeholders think the NGL and NGR are working effectively and have sufficient flexibility to deal with changing conditions. Concerns have been raised though by a small number of stakeholders about: ▪ the potential for different forms of regulation applying to transmission pipelines to create uncertainty and inefficiencies for those seeking to transport gas between jurisdictions; ▪ the form of regulation to be applied to distribution pipelines, with some contending these pipelines should be regulated in the same manner as electricity networks and others noting this is not appropriate given the different conditions in which they operate; and ▪ the effect that certain provisions in the NGR (ie, the advance determination on capital expenditure provisions, the speculative capital expenditure provisions and the redundant asset provisions) may be having on investment.
DWGM and STTM	STTM	The views on the STTM were mixed, with some stakeholders questioning its value while others claimed it provides an effective mechanism for trading imbalances. Those questioning its value, claim it has imposed substantial costs on participants and pipeline owners, given rise to significant risks that can't be hedged and may be distorting locational decisions and/or deterring entry. Although some stakeholders were quite critical of the STTM, there does not appear to be a strong desire to abandon the markets, at least not in Sydney or Adelaide. Rather, they would prefer to address the deficiencies in the current market design and have therefore suggested a range of improvements, such as: developing a single end of day gas price that can be used as the basis for developing financial hedging products; reviewing the current Market Operator Service (MOS); harmonising the start of gas day in the DWGM and STTM and, potentially, the market price caps and prudential requirements; addressing the limitations currently prevailing in the Brisbane STTM; and developing an implementation plan for the introduction of intra-day trading, if appropriate.

Topic		Comments
	DWGM	There is general perception amongst stakeholders that the DWGM is working relatively well, although some have claimed it is getting more complex to operate in. Concerns have also been raised about the inability to hedge against all risks in the DWGM, given the range of uplift charges, which are not reflected in the gas price.
	Rule changes	Stakeholders were critical of the time it can take for DWGM and STTM related rule changes to come into effect and have suggested steps be taken to eliminate any unnecessary duplication of consultation between the processes run by AEMO and the AEMC. A number of stakeholders were also critical of the restriction on who can propose DWGM related rule changes.
Greater interaction with the NEM		A number of stakeholders questioned the need for any greater convergence between gas and electricity markets, while those with gas fired generation interests noted that further integration and consistency may be required in the future. Those noting the potential for further integration and consistency to occur in the future, were of the view though that there is no urgency to deal with this given current electricity market conditions. The two potential areas of the current arrangements that stakeholders noted could be harmonised are the market price caps prevailing in the NEM, the STTM and DWGM and the prudential requirements across the gas markets.
Retail markets		Some retailers have claimed that further efficiencies could be achieved if there was a greater degree of standardisation of: ▪ the manner in which retailers interface with gas distribution pipelines; and ▪ the terms and conditions of access specified in distribution pipelines' access arrangements. A small number of retailers also expressed some concerns about the potential for a significant increase in wholesale gas prices brought about by the LNG developments, to prompt policy makers to try to shield customers from higher prices by imposing a cap on retail gas prices that doesn't allow retailers to recover their efficient costs.
Information		Concerns were raised by a number of stakeholders about: ▪ the level of information currently available on the Bulletin Board; ▪ the fact that some facilities are not designated Bulletin Board facilities; and ▪ the quality and accessibility of the existing STTM, DWGM and Bulletin Board data. One stakeholder also noted that information on the costs of transporting gas between various locations in south eastern Australia and Gladstone should be more readily available so that there is a common reference point for the transportation cost component of the LNG netback price at different supply sources. While a range of improvements have been suggested, some stakeholders stated that the provision of such information is not without cost.
Inter-jurisdictional emergency arrangements		Most stakeholders are of the view that the arrangements are working effectively and that AEMO and industry have the right level of involvement through the National Gas Emergency Response Advisory Committee (NGERAC). However, some stakeholders have noted the need for greater transparency around the curtailment principles employed by jurisdictions in an emergency and a more comprehensive set of information than is currently available on the Bulletin Board to be made available during emergencies so they can be effectively managed.

Scoping study findings

As the comments in Table E.2 highlight, there are a number of perceived deficiencies with the current regulatory and market arrangements and the manner in which policy and market development has occurred over the last two to three years. Based on our own high level review of these arrangements, we would agree that:

- market development over the last two to three years appears to have been occurring in a relatively fragmented manner and without a clear strategy for how the market can make the transition from its current, relatively immature state, to a more mature, well-functioning market (comprising commodity, transportation and financial markets); and
- certain elements of the current arrangements may be adversely affecting the productive, allocative and/or dynamic efficiency of the provision of natural gas services and therefore warrant closer attention. The specific areas of the current arrangements we think should be subject to further investigation and/or market development work by SCER, the AEMC, AEMO and/or industry include:
  - the design and operation of the STTM and DWGM (high priority);
  - the DWGM and STTM rule change process (medium priority);
  - investment under the Victorian market carriage model (medium priority);
  - capacity trading on contract carriage pipelines (medium priority);
  - the potential for a greater level of consistency between the market price caps and prudential requirements in the NEM, the STTM and DWGM (low priority);
  - the potential use of retail price caps in response to higher gas prices (low priority);
  - the quality, comprehensiveness and accessibility of STTM, DWGM and Bulletin Board information (low priority); and
  - the inter-jurisdictional emergency arrangements.

Further detail on each of these issues is provided below, while Table E.1 contains a summary of our key recommendations. Before moving on though, it is worth noting that the relatively short period for completing this scoping study has only allowed a very high level review of the issues. The findings of the scoping study should therefore be viewed in this light.

Strategic review of future market development – high priority

A common theme emerging from many of our discussions with stakeholders is that gas market development in eastern Australia over the last two to three years has occurred in a relatively ad-hoc manner and without a clear strategic direction of how the market can make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports:

- the efficient allocation of gas and transportation capacity in the short, medium and long term;
- the efficient trade and movement of gas between jurisdictions;

- efficient and timely investment in upstream production and transportation capacity; and
- the efficient allocation of risks between market participants and allows participants to hedge risks.

In our view, this constitutes a real gap in the market and, if not addressed, could result in the implementation of sub-optimal market development decisions that:

- risk undermining confidence in the market; and
- may result in a reduction in the productive, allocative and/or dynamic efficiency of the eastern Australian gas market and other downstream markets, and, in so doing, adversely affect the long term interest of consumers.

Consistent with SCER's policy principle of 'promoting market development', we would therefore recommend that steps be taken to fill this gap over the next 12-18 months through a strategic review that considers both:

1. the direction that facilitated markets in eastern Australia should take over the next ten to fifteen years if the market is to make the transition to a more mature and well-functioning market that exhibits the characteristics set out above. Some of the matters we think would be relevant to consider in this context include:
   - what the market can be expected to look like if it evolves in this manner;
   - the likely optimal structure and location of facilitated markets, given the characteristics of the market and the need to attract depth and liquidity;[15,16]
   - the pre-conditions for the market to evolve in this manner, how long it is likely to take and any intermediary steps the market is likely to have to take;
   - whether the market, if left to its own devices, will evolve in this manner, or whether some form of policy intervention might be required to support the development;
   - the relevance of the experience garnered in other international markets;
   - how a well-functioning financial market can be developed; and
   - whether the existing facilitated markets (eg, the DWGM and STTM) are meeting their stated objectives in the most efficient manner and if the development of any new facilitated markets may obviate the need for any of the existing facilitated markets.

15 Some of the characteristics that will be important to consider in this context are: the small number of players in the market, the geographic dispersion of players, the difference in the nature of demand across locations, the potential for medium to long term contracts to continue to have a role in the market over the longer run and the level of liquidity in the market. One other point to bear in mind is that a one size fits all approach may not be appropriate given differences in physical and regulatory arrangements prevailing in each jurisdiction.

16 As a general observation, given the size and nature of the market, it is unlikely that the eastern Australian gas market could support more than one upstream supply hub that acts as a reference point for wholesale gas prices because, as one stakeholder pointed out, there is only a finite amount of liquidity in the market and dividing this across multiple supply hubs could undermine the efficiency of the price signal. See Origin, Submission to Gas Market Scoping Study, 14 June 2013, p.2.

2. the principles that should guide the development of facilitated markets in the future. Some of the matters we think would be relevant to consider in this context include:
   - the circumstances in which it will be appropriate to employ particular types of facilitated markets and the importance of having regard to market characteristics;
   - how a market should be designed, so as to minimise costs and risk exposure, and to provide an appropriate basis for the development of financial hedging products; and
   - the assessment framework to be used when deciding to implement a new market.

In keeping with the allocation of functions and responsibilities set out in the National Gas Law (NGL), we are of the opinion that:

- the review should be sponsored by SCER; and
- consistent with its market development function under the NGL, the AEMC should be accorded responsibility for actually carrying out the review.

In keeping with its standard practice, we would expect the AEMC to carry out such a review in close consultation with industry and other key stakeholders, such as AEMO and the AER.

Design of the DWGM and STTM – high priority

One of the more significant areas of the current arrangements that, in our opinion, warrants further work, is the design of the STTM and, to a lesser extent, the DWGM. Based on our high level review of the DWGM and STTM, it would appear that while the imbalance components of these markets are working relatively effectively, some of the ancillary components,[17] may be imposing costs on participants (and, in turn, consumers) and giving rise to risks that cannot be effectively hedged.

Some other general observations we would make about these markets are that:

- Inconsistencies between the risk management frameworks adopted in both markets and differences between other market design elements may be imposing unnecessary costs on market participants operating across the two types of markets.
- Certain elements of the two markets are complex, which in addition to imposing costs on market participants, may be deterring entry into these markets.
- There appears to be some specific design issues in the Brisbane STTM, which may be affecting the efficacy of this market.
- The continued expansion of renewable generation could result in a greater degree of volatility in the Adelaide STTM and the DWGM and expose participants to greater risk.

While we are not in a position to quantify the extent to which these issues are affecting the efficient trade of gas, or imposing unnecessary costs and risks on market participants, stakeholder feedback suggests they are having a material effect and that the effect is being felt more acutely in the STTM. There appears therefore to be a case for carrying out a more

[17] For example, the ancillary payment/uplift component of the DWGM and the MOS/deviation component of the STTM.

detailed review of the design of the STTM to determine whether it can be improved. Given it has been over nine years since a detailed review of the DWGM has been carried out,[18] there may also be value in carrying out a review of particular elements of this market, in conjunction with the review of the STTM.

Ideally such a review would follow the strategic review outlined in the preceding section, because one of the issues the strategic review will look at is the effectiveness of the existing facilitated markets. To ensure the scope of this review does not become too broad, and that the level of effort is proportionate to the underlying issues, we would suggest that SCER and the AEMC work together to prepare draft terms of reference at the completion of the strategic review. At this stage it is difficult to determine precisely what the scope of the review will be and whether the AEMC and/or AEMO should be responsible for carrying out such a review. We would therefore suggest this be considered by SCER when preparing the draft terms of reference, having regard to the functions of both organisations as set out in sections 69 and 91A of the NGL. In principle, the AEMC should be responsible for defining the high level design of these markets, while AEMO should be responsible for carrying out the detailed design and implementation work.

DWGM and STTM rule changes – medium priority

Two other issues that became clear from our review of the STTM and DWGM and the consultation process are that:

- The time taken to develop, review and implement STTM and DWGM related rule changes has been protracted and may be imposing unnecessary costs on market participants. We would therefore recommend that AEMO and the AEMC work together over the next six months to determine whether the consultation process can be streamlined, taking into account their respective consultation obligations under the NGL and NGR. To the extent provisions in the NGL or NGR are acting as an impediment to such streamlining, this issue may need to be escalated to SCER.
- The legislative restriction[19] on who can propose DWGM related rule change (ie, AEMO and the Victorian Minister only) may need to be reviewed by the Victorian Department of State Development, Business and Innovation (DSDBI) (formerly the Victorian Department of Primary Industries (DPI)), because it has been claimed that this restriction may be resulting in sub-optimal outcomes. While we are not in a position to test this claim, we do think there would be value in DSDBI considering whether the restriction it is still appropriate and, if so, whether improvements can be made to the current process.

Victorian market carriage model– medium priority

The Victorian market carriage model has a number of positive attributes, including open access, relatively low barriers to entry and exit, and also appears to promote efficient

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18 VENCorp, Victorian Gas Market Pricing and Balancing Review – Recommendations to Government, 30 June 2004, p.11.

19 Section 295(3)(a) of the NGL currently prevents anyone other than AEMO or the Victorian Minister for Energy and Resources from submitting a DWGM related rule change request to the AEMC.

utilisation of the Declared Transmission System (DTS) and dynamic efficiency in both upstream and downstream markets. Concerns have, however, been raised by stakeholders about the timeliness and efficiency of investment in the DTS and, to a lesser extent, the ability to export gas via the DTS.

Although a significant amount of investment (including export capacity related investment) has recently been approved by the AER and exports via the DTS are increasing, the issues raised by stakeholders are, in our view, still worth exploring. In short, it would appear from our review that a number of factors have contributed to the investment and export issues observed in Victoria. The root cause of most of the issues can, however, be traced back to the fact that market participants are unable to obtain exclusive firm capacity rights on the pipeline system under the existing model. Investment decisions in the DTS are therefore driven by the regulatory process, which may be less efficient and timely than relying on market driven investment incentives.

In our opinion, there are two potential review options that could be taken to promote improved investment outcomes in the DTS, which differ depending on whether the investment issues are viewed as a deficiency in the regulatory process or market design. These options are not necessarily mutually exclusive, but differ substantially in the level of effort and time required, and the chances of success. The two options are:

Option 1: Review regulatory investment processes and application – this review would involve a holistic assessment of the regulatory investment process and application of this process in Victoria by both the AER and the owner of the DTS. In our view, this review could be undertaken in a timely manner, would not be overly complex, may produce workable improvements and would still be of benefit even if the Option 2 review is carried out.

Option 2: Investigate and if feasible implement transmission rights – this work would be complex, time consuming and at this stage does not have a clear prospect for success. Before progressing down this path, we would therefore suggest the AEMC carry out an internal review on the prospects for introducing tradable transmission rights and only proceed to a more detailed public review if such rights are considered likely to provide improved investment signals in the DTS.

At this stage we would recommend commencing work on Option 1 and the internal review under Option 2, but only proceeding to the detailed review under Option 2 if the internal review reveals it is likely to be beneficial. In terms of who should be responsible for carrying out either of these reviews and what priority it should be accorded, we are of the opinion that:

- SCER should sponsor the review(s) while the AEMC should carry out the review(s); and
- that there is no great urgency for either review to be carried out given investment and exports are currently occurring. However, if a decision is made to go down either of these paths, they would ideally be carried out in the next one to two years, so any changes can be reflected in the next access arrangement, to be reviewed in 2017.

Capacity trading under the contract carriage model – medium priority

Unlike the Victorian market carriage model, investment in contract carriage transmission pipelines has reportedly been timely and efficient. We understand, however, that questions have been raised by SCER and AEMO about the efficiency with which fully contracted contract carriage pipelines are being utilised and that they are both currently exploring options to encourage a greater degree of capacity trading.

At the outset it is worth pointing out that it is difficult to determine how significant an issue this is given the lack of data on how much secondary trading occurs and how much unmet demand there is for this type of service. However, based on our review of the incentives and abilities of shippers and pipeline owners to on-sell spare contracted but unutilised capacity and the feedback received from stakeholders, it would appear that:

i. Shippers (through a capacity trade) and pipeline owners (through 'as available' contracts)[20] can sell unutilised contracted capacity and there are no significant commercial impediments to these types of transactions taking place.

ii. Apart from pipelines with multiple injection and withdrawal points (eg, the RBP), there do not appear to be any technical impediments to these types of transactions occurring.

iii. Shippers and pipeline owners should have an incentive to sell any spare capacity and, in theory, should compete against each other to sell the capacity. The latter of these points is of particular importance, because while a shipper may appear to have little incentive to sell spare capacity to a downstream competitor, the fact that a pipeline owner can sell that same capacity on an 'as available' basis, should encourage the shipper to compete to supply the service and recover some of its fixed transportation costs.

iv. 'As available' capacity trades or sales by pipeline owners are only likely to occur at the margin because the nature of most buyers' gas requirements is such that they require access to firm transportation services.

v. In terms of the transaction and co-ordination costs, it appears that a distinction can be drawn between:

  - spot or very short term trades – on a $/GJ basis the transaction and co-ordination costs associated with these trades are likely to be:

    - relatively high for formalised capacity trades because shippers are unlikely to have contracts or processes in place to readily enter into these types of transactions; and

    - lower for 'as available' transactions, because pipeline owners have established processes (eg, standard contracts) in place to minimise transaction costs.

[20] If the *contracted* capacity is not being fully utilised by the contracting shipper(s), a pipeline owner may offer the unutilised capacity to other shippers on an 'as available' basis. For transactions involving the transportation of gas more than one day ahead, the capacity can only be sold on an 'as available' basis because it is possible that the contracting shipper may decide to use its entire capacity reservation on any particular day. For spot or day ahead sales of transportation services, pipeline owners can offer a service that is more akin to a firm service than an 'as available' service because it will know what its shippers' nominations are when such transactions are entered into.

- other longer term transactions (eg, monthly, seasonal or longer term transactions) – the transaction and co-ordination costs in this case, when expressed on a $/GJ basis, will be much lower for both capacity trades between shippers and as available sales by pipeline owners, because fixed costs will be spread across a greater volume of gas.

Based on this synopsis, it would appear that a distinction can be drawn between:

- the ease with which trades of different duration can be entered into; and
- capacity trading on pipelines with multiple injection and withdrawal points versus simple point-to-point pipelines.

For longer term trades (eg, monthly, seasonal or longer term transactions), it would appear that shippers and pipeline owners have the appropriate incentive and ability to sell unutilised contracted capacity and that transaction and co-ordination costs are unlikely to act as an impediment to such trade. There does not therefore appear to be any failure in this segment of the market that would require the introduction of a regulatory measure to encourage a greater level of this type of trading.

For spot or very short term trades, shippers and pipeline owners should also have the appropriate incentive and ability to sell unutilised contracted capacity. However, it is possible that the transaction and co-ordination costs associated with formalised capacity trades may act as an impediment to these types of trades. This is unlikely to be an issue though for sales of ‘as available’ services by the pipeline owner.

While we recognise that spot and very short tern trades are only likely to occur at the margin (given both the nature of demand and current contracting practices), we can see there may be some value in trying to reduce the transaction and co-ordination costs associated with such trades, so that they can occur more readily if required (eg, during an emergency or to facilitate trade in the Wallumbilla gas supply hub). Some of the measures we think would be useful to consider in this context include:

- developing standardised contracts for use by shippers to facilitate formalised capacity trades; and
- developing a new section on the Bulletin Board (see rule 176 of the NGR) that can be used by participants wishing to trade spare capacity.

Ideally, this work would be led by industry, or they would be closely involved in the identification of the solutions, given they are the ones that will be involved in the transactions and have a good understanding of their transportation requirements and contracts.

One other point of distinction emerging from our discussions with stakeholders is that there can be technical impediments to trading capacity on pipelines with multiple injection and withdrawal points (eg, the RBP) because the capacity on one part of the pipeline may depend on what is being injected and withdrawn on another part of the pipeline.[21] Trades between

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[21] This is similar in some ways to what occurs on a meshed network like the DTS.

parties using different injection and/or withdrawal points can therefore be difficult to co-ordinate from a system operation perspective. Because this impediment stems from the physical characteristics of the pipeline, it is unlikely that the solutions being considered by SCER or AEMO will give rise to efficiency improvements from additional capacity trading on these types of pipelines.

Greater interaction with the NEM – low priority

The current outlook for gas fired generation in the NEM is such that there does not appear to be any urgency to consider whether a greater degree of interoperability, risk management and consistency between the NEM and imbalance markets is required. Having said that, we do think there would be value in either:

- a detailed review being carried out by the AEMC in the medium term (or if there is a significant change in climate change polices and/or conditions in the NEM that supports gas fired generation), to get a better understanding of the interactions between the two markets and to ensure that the existing arrangements are fit for purpose; or
- having the AEMC or AEMO consider the question of whether a greater degree of consistency between the market parameters in the NEM and the imbalance markets is appropriate, as part of the STTM and DWGM review. One point that will need to be borne in mind when considering this question, is that gas fired generators currently only account for around 30% of the gas consumed in eastern Australia.[22] Careful consideration will therefore need to be given to the costs and risks that any harmonisation measure may have on the remaining 70% of the market, with consistency only being pursued if the benefits outweigh all of the costs and risks imposed on the market.

Given stakeholders have to date only focused on the potential benefits that may arise if there is a greater level of consistency between the market price caps and prudential requirements, we would recommend pursuing the latter option in the first instance and only carrying out a detailed review if greater convergence between the gas and electricity markets becomes more likely.

Retail markets – low priority

One potential risk we have identified with the changes currently underway in the market is that as higher wholesale gas prices start to flow through to residential customers (est. 2015-2018), policy makers may try to protect residential customers by imposing a cap on retail prices that prevents retailers from recovering their efficient costs. While there has been no indication that any jurisdictions are currently considering this type of policy response, it is a risk we think the AEMC should be cognisant of and, if there is any indication this option may be pursued, the AEMC should liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition.

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22 AEMO, 2012 GSOO, Appendix A-1.

Information – low priority

During the consultation process concerns were raised about: the level of information currently available on the Bulletin Board; the fact that some facilities are not designated Bulletin Board facilities; and the quality and accessibility of STTM, DWGM and Bulletin Board data.

We understand that the first of these matters was recently considered by AEMO and that a rule change request will shortly be provided to the AEMC. In relation to the second matter, we agree that this should be reviewed by AEMO and that it should use its declaration powers under rule 153 of the NGR if necessary. On the final matter, we agree that the quality and accessibility of the STTM, DWGM and Bulletin Board data could be improved. It is unclear though how material an issue this is and what the costs are likely to be to rectify this. We would therefore suggest that AEMO consider this further and engage with its consultative forums to determine what, if any, improvements can be made.

Emergency arrangements

Each jurisdiction in Australia has its own emergency powers that can be exercised by a Minister or agency during an emergency. The Commonwealth, states and territories have also developed the National Gas Emergency Response Protocol Memorandum of Understanding (MoU),[23] the purpose which is to facilitate the efficient, effective and nationally consistent management of emergencies extending beyond a single jurisdiction.

It is beyond the scope of this study to conduct a detailed review of these emergency arrangements but, based on comments received from stakeholders, there do not appear to be any fundamental problems with the existing arrangements. Having said that, we do think there would be value, from both a reliability and security of supply perspective, in:

- Improving the transparency and accessibility of the arrangements, by either moving the arrangements into the NGL/NGR or updating the MoU and making it more accessible.
- Clearly specifying in the NGL/NGR or MoU: the role to be played by AEMO within National Gas Emergency Response Advisory Committee (NGERAC); the circumstances in which NGERAC will be convened; any immunity NGERAC and AEMO may have from liability; and the principles that should underpin the jurisdictional curtailment tables and commercial gas sharing arrangements.
- Formalising the obligations industry have to provide information to NGERAC.
- Reviewing the list of Bulletin Board facility operators to ensure it is appropriate.
- Reviewing jurisdictional curtailment tables to determine whether they are appropriate given the changes currently underway in the market and consistent with the curtailment principles that NGERAC has developed. One other issue that should be considered is whether part, or all, of the jurisdictional curtailment tables should be made publicly

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23 A copy of the MoU can be found on AEMO's website http://www.aemo.com.au/Gas/Policies-and-Procedures/Gas-Emergency-Procedures/NGERAC-Emergency-Protocol

available so that industry have a better idea about the likelihood they will be curtailed and choose how to manage the risk *before* a jurisdiction exercises its emergency powers.

Because the emergency arrangements do not currently form part of the NGR and any work in this area will require the agreement of the jurisdictions, we would recommend the AEMC refer stakeholder comments and our observations on this issue to SCER and DRET (as chair of NGERAC), who may then consider whether to take the suggested changes forward.

1. Introduction

As part of the Strategic Priorities for Energy Market Development 2013 Review, the Australian Energy Market Commission (AEMC) announced that it would be undertaking a gas market scoping study in the first half of 2013[24] and that the study would entail:

- reviewing, at a high level, the regulatory and market arrangements applying to the supply of gas from the time it enters a transmission pipeline to the time it reaches end-users;
- engaging with stakeholders to get a better understanding of how well they think the current arrangements are working and to get their perspectives on whether any improvements could be made that would promote the National Gas Objective (NGO);
- identify areas of potential improvement in the current regulatory and market arrangements that could promote efficiency in the long term interests of consumers and that may benefit from more detailed market development work; and
- better understand the strategic framework and direction of the gas market to inform its consideration of how individual rule changes contribute to that direction.

The AEMC's decision to undertake the scoping study was prompted by both:

- the recognition that structural changes currently underway in the eastern Australian gas market could affect the manner in which gas and transportation capacity is traded in the future and could also have implications for the movement of gas; and
- an understanding that while greater convergence between gas and electricity markets is unlikely to occur in the short to medium term, the gas market arrangements should be fit for purpose over the longer term, in anticipation of increased convergence in the future.

While it is recognised that a study of this nature will not address the more fundamental upstream supply issues currently affecting the eastern Australian gas market, the AEMC still considers it worthwhile taking stock of the current arrangements and considering whether:

- the current arrangements are likely to continue to support the efficient movement and trade of gas in eastern Australia, given the changes currently underway in the market;
- the contract carriage, market carriage and gas pipeline regulatory arrangements are promoting efficient investment in, operation and use of gas pipelines;
- the facilitated markets are encouraging the efficient trade of gas; and
- greater interoperability, risk management and consistency between gas and electricity markets are required.

To assist with its consideration of these issues, the AEMC has asked K Lowe Consulting (KLC) to prepare a report that:

Part A. provides a comprehensive overview of the state of the gas market; and

Part B. identifies whether there are any areas of the existing market and regulatory arrangements that may benefit from future market development work, prioritises their importance and identifies who is best placed to take it forward.

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24 AEMC 2013, Strategic Priorities for Energy Market Development 2013 Discussion Paper, p. 41.

The AEMC has also asked Farrier Swier Consulting to peer review the findings in Part B.

In relation to Part B, the AEMC has made it clear that the purpose of the scoping study is *not* to identify and evaluate solutions. Rather, the task at this stage is to identify the issues, assess their materiality and identify who may be best placed to take them forward. The AEMC has also made it clear that the primary focus of the study should be the eastern Australian gas market, but to the extent any issues are raised about the regulation of gas pipelines, consideration should also be given to the implications this may have for Western Australia and the Northern Territory.

The three matters set out above are considered, in turn, in the remainder of this report, which consists of the following parts:

- **Part A** provides an overview of the eastern Australian gas market and the regulatory and market arrangements applying to the supply of gas from the time it enters a gas transmission pipeline to the time it is delivered to end-users. These issues are explored in chapters 2-7 of this report, which have been structured as follows:
  - chapters 2-3 provide an overview of the eastern Australian gas supply chain and the demand for gas by the domestic market in eastern Australia;
  - chapter 4 outlines the changes currently occurring on both the demand- and supply-sides of the market, how those changes are expected to affect the demand-supply balance and gas prices, and the uncertainties currently afflicting the market;
  - chapter 5 describes how gas and transportation services are currently acquired;
  - chapter 6 provides an overview of the facilitated markets currently operating in Victoria, Adelaide, Brisbane and Sydney and the new Wallumbilla supply hub; and
  - chapter 7 outlines the institutional and regulatory frameworks applying to gas pipelines and the facilitated markets, and the arrangements that have been put in place to deal with gas emergencies affecting more than one jurisdiction.
- **Part B** outlines the issues raised by stakeholders during the consultation process and sets out the findings of the scoping study. These issues are considered in chapters 8-10 of this report, which have been structured as follows:
  - chapters 8-9 outlines the purpose of the study and the assessment framework that has been employed;
  - chapter 10 provides an overview of the issues raised by stakeholders; and
  - chapter 11 considers the extent to which any particular areas of the current market or regulatory arrangements may benefit from more detailed market development work.

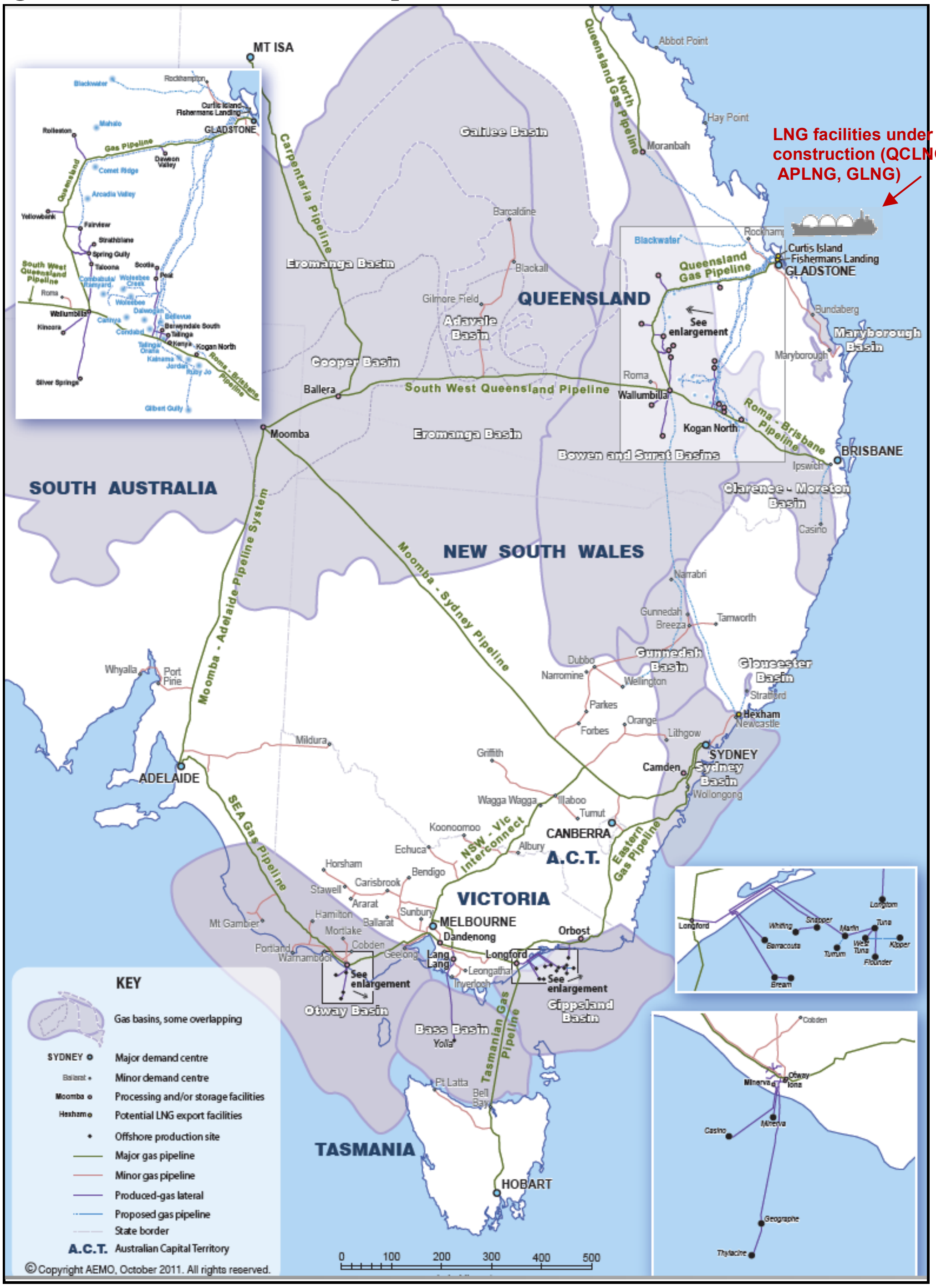
Before moving on, we would like to take the opportunity to thank stakeholders for making themselves available throughout the study and for providing their insights into the range of issues currently affecting the market and market participants. We would also like to thank Farrier Swier Consulting for the valuable insights provided through the peer review of chapters 7-11.

PART A:
Overview of Eastern Australian Gas Market & Market/Regulatory Arrangements

2. Eastern Australia Gas Supply Chain

Natural gas in eastern Australia is currently produced in a number of conventional natural gas and coal seam gas (CSG) fields in Victoria, South Australia, Queensland and New South Wales. The gas produced in these fields is then transported via high pressure transmission pipelines from the production facility to the entry point of a distribution system (the city gate), or to large users connected to the transmission pipeline. Gas entering the distribution system is then transported under low pressure to the end-user's delivery point. The map below illustrates the location of the sources of gas in eastern Australia and the transmission pipelines servicing major demand hubs.

Figure 2.1: Gas basins and transportation infrastructure in eastern Australia



Source: AEMO, 2012 Gas Statement of Opportunities. Amended to reflect the location of LNG facilities.

The remainder of this chapter provides an overview of the key elements of the gas supply chain in eastern Australia, with particular emphasis placed on:

- the current sources of supply in eastern Australia;
- the major transmission pipelines currently used to transport gas in eastern Australia;
- the distribution systems used to transport gas in each of the capital cities;
- the storage options available to buyers and producers in eastern Australia; and
- the locations where gas was produced and supplied to in 2012.

2.1 Sources of supply

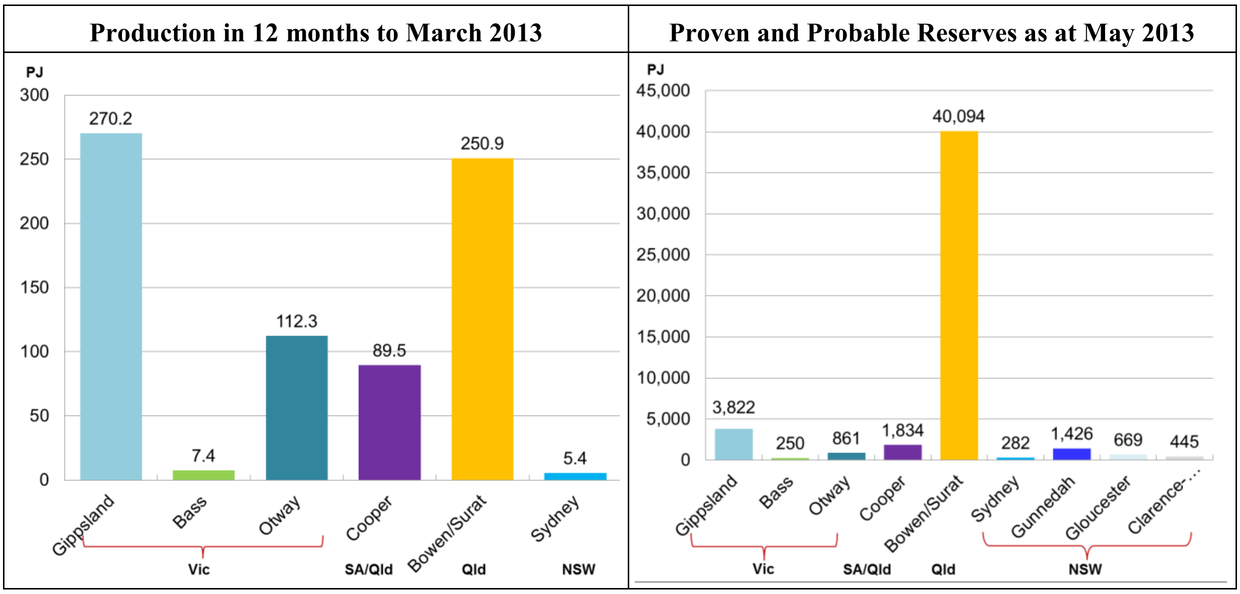
Conventional natural gas in eastern Australia is currently produced in a number of fields in the Gippsland, Otway, Bass, Cooper and Bowen/Surat basins, while CSG is produced in a number of fields in the Bowen/Surat and Sydney basins. Table 2.1 sets out EnergyQuest's most recent estimates of the gas produced, and proven and probable reserves certified in each of these basins. The relative size of each basin, in terms of production and reserves, is depicted in Figure 2.2.

Table 2.1: Production and proven and probable reserves

Basin	Field	Ownership Interests	Production 12 months to March 2013	Reserves as at May 2013
Cooper	Moomba (SA)	66.6% Santos, 20.2% Beach, 13.2% Origin	89.0	1,832
	Ballera (Qld)	60.0625% Santos, 23.2% Beach, 16.7375% Origin		
	Other		0.5	1
	Total		**89.5**	**1,834**
Gippsland	Bass Strait	50% BHP Billiton, 50% ExxonMobil	257.7	3,115
	Longtom	Nexus	12.5	85
	Kipper	35% Santos, ExxonMobil 32.5%, BHP 32.5%	0	622
	Total		**270.2**	**3,822**
Otway	Minerva	90% BHP Billiton, 10% Santos	25.6	118
	Casino, Henry, Netherby	50% Santos, 25% AWE, 25% Mitsui	35.1	275
	Geographe/ Thylacine	67.23% Origin, 27.77% Benaris, 5% CalEnergy	51.6	467
	Jacaranda Ridge	Beach Energy	0	1
	Total		**112.3**	**861**
Bass	Yolla	42.5% Origin, 46.25% AWE, 11.25% Toyota Tsusho	7.4	250
	Total		**7.4**	**250**
Bowen/Surat	APLNG operated fields (Origin, ConocoPhillips and Sinopec)		110.8	13,447
	GLNG operated fields (Santos, Petronas, Total and Kogas)		44.9	5,376
	QCLNG operated fields (BG, CNOOC and Tokyo Gas)		52.9	10,494
	Arrow operated fields (Royal Dutch Shell and PetroChina)		28.1	7,041
	WestSide operated fields		2.0	680
	PetroChina operated fields		0	512
	Other (includes AGL, Mitsui, Toyota Tsusho, Stanwell, Senex, Blue Energy and other interests held by Origin, Santos, BG and Arrow)		12.2	2,544
	Total		**250.9**	**40,094**
NSW	Sydney and Gloucester basins	AGL	5.4	951
	Gunnedah Basin	Santos 80%, Energy Australia 20%	0	1,426
	Clarence-Moreton basins	Metgasco	0	428
		Red Sky Energy	0	17
	Total		**5.4**	**2,822**
Total			**735.6**	**49,682**
LNG proponents			***236.7***	***36,358***
Other producers			***498.9***	***13,324***

Source: EnergyQuest, EnergyQuarterly, May 2013

Figure 2.2: Production and proven and probable reserves by basin

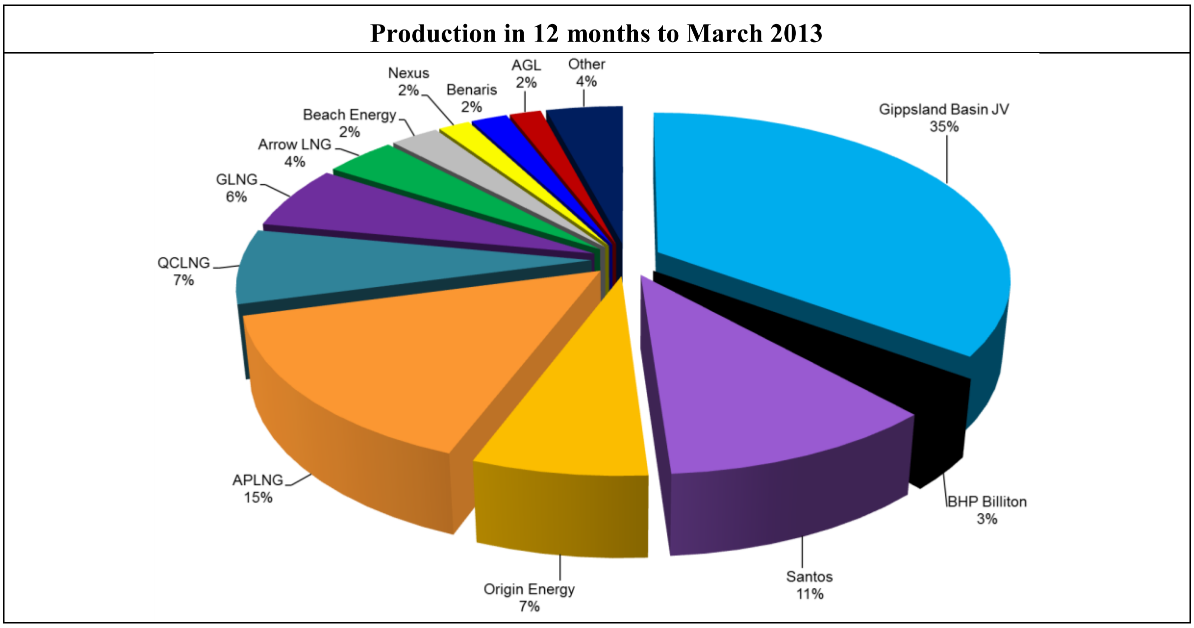


Source: EnergyQuest, EnergyQuarterly, May 2013

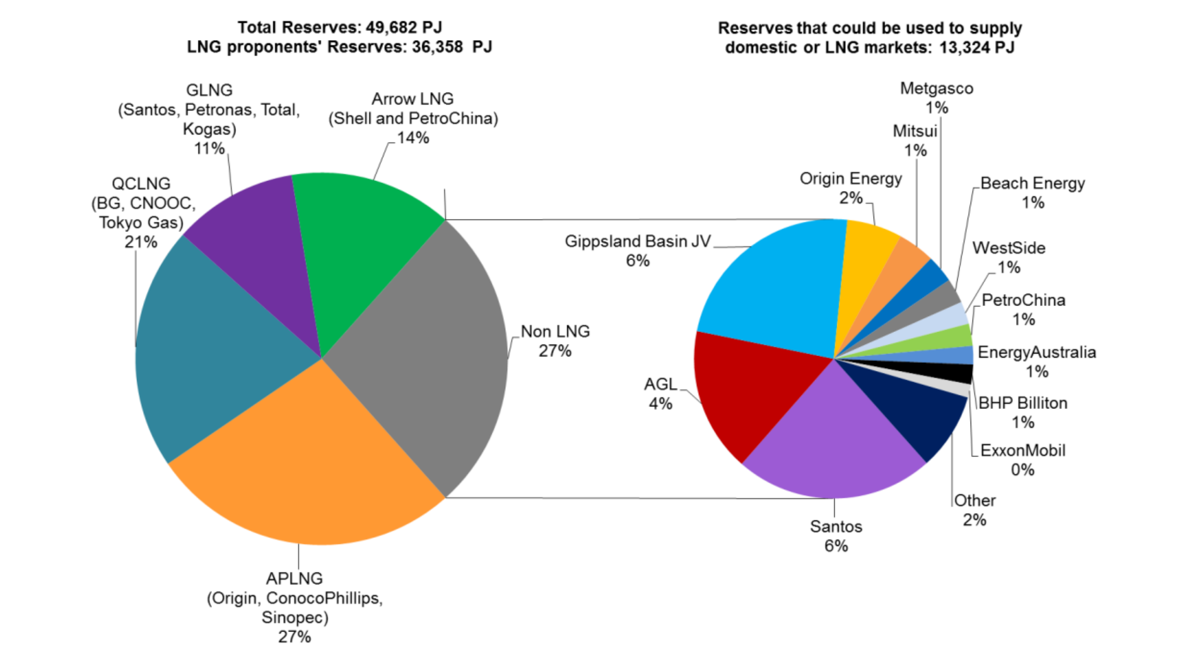
As Figure 2.2 reveals, the Gippsland and Bowen/Surat basins were the largest producers of gas in the 12 months to March 2013, jointly accounting for 71% of the gas produced in this period (Gippsland Basin: 37% and Bowen/Surat basins: 34%). The remaining 29% was produced in the Otway (15%), Cooper (12%), Bass (1%) and Sydney (1%) basins. In terms of reserves, the Bowen/Surat basin, which is where the LNG proponents are located, accounted for 81% of the proven and probable reserves certified as at May 2013, while the Gippsland Basin accounted for 8%, the Cooper Basin 4%, the Gunnedah Basin 3%, the Otway Basin 2% and the remaining basins 1%, respectively.

The share of production and proven and probable reserves accounted for by the larger producers and LNG proponents is illustrated in Figure 2.3.

Figure 2.3: Interests in production and proven and probable reserves



Proven and probable reserves as at May 2013



Source: Based on data from EnergyQuest, EnergyQuarterly, May 2013.

One important point to note from Figure 2.3 is that while it would appear that there is a reasonable degree of diversity in the upstream segment of the supply chain, control of the more significant fields in the Gippsland, Cooper and Otway basins is largely concentrated in the hands of the Gippsland Basin JV (BHP Billiton and ExxonMobil), Santos and Origin. Fields in the Bowen/Surat basins, on the other hand, are predominantly controlled by four LNG proponents, APLNG, QCLNG, GLNG and Arrow LNG. Combined, these players accounted for 85% of the gas produced in the 12 months to March 2013 and 87% of the proven and probable reserves certified as at May 2013.

Another interesting point to note from Figure 2.3 is that the three largest gas retailers, AGL, Origin and EnergyAustralia, have interests in upstream production and/or reserves. While Origin has been involved in the upstream segment for quite some time, AGL and EnergyAustralia's entry into this segment of the supply chain has been more recent, with AGL entering in 2005[25] and EnergyAustralia in 2011.[26]

One final point that is worth noting in this context is that if the LNG proponents' interests in proven and probable reserves are excluded (36,358 PJ) from the total reserves, the reserves that could be used to supply either domestic users or the LNG market would be around 13,324 PJ (which is 18 times the volume of gas consumed in eastern Australia in 2012). Of the 13,324 PJ, the Gippsland Basin JV jointly account for 23%, Santos 23%, AGL 17% and Origin 6%. Other parties that have an interest in these reserves include Mitsui, Metgasco, Beach Energy, WestSide, PetroChina, EnergyAustralia, BHP and ExxonMobil. In relation to

[25] This occurred when AGL formed a joint venture with Sydney Gas in the Sydney Basin.

[26] This occurred when EnergyAustralia formed a joint venture with Santos in the Gunnedah Basin.

the reserves accounted for by Santos, AGL, EnergyAustralia and Metgasco, it is worth noting the following:

- Over a third of Santos and AGL's reserves and all of EnergyAustralia's reserves are located in basins that are *not* currently connected by a pipeline to an end-market (ie, the Gunnedah and Gloucester basins).
- Over 10% of AGL's reserves and all of Metgasco's reserves are located in areas that are unlikely to be developed following the introduction of the NSW Government's new Strategic Regional Land Use Policy (see Box 2.1).

In total, these reserves amount to around 20% of the 13,324 PJ of certified reserves.

Box 2.1: NSW Government's Strategic Regional Land Use Policy

On 19 February 2013, the NSW Government announced that new measures would be put in place to limit CSG activity in residential areas and 'critical industry clusters'. Some of the more significant measures are set out below:

- a 2 km exclusion zone will apply to all residential areas, which will prohibit any new exploration or production activities;
- exclusion zones will also apply to any areas that are identified as being part of a critical industry cluster (eg, viticulture and equine industries);
- all exploration, assessment and production titles and activities will need to hold an Environment Protection Licence; and
- an office of CSG Regulation will be established within the Department of Trade and Investment to enforce regulations.

Source: Barry O'Farrell and Andrew Stoner, Tough New Rules for Coal Seam Gas Activity, 19 February 2013.

2.2 Transmission pipelines

Transmission pipelines enable gas to be transported under high pressure from production facilities to either the entry point of the distribution system or directly to users that are connected to the transmission pipeline. Over the last ten years there has been significant investment in this segment of the gas supply chain, with both:

- a number of new pipelines being constructed (eg, the SEA Gas Pipeline in 2004, the QSN Link in 2009 and the three LNG pipelines currently under construction); and
- the capacity of a number of others being expanded (eg, the Eastern Gas Pipeline (EGP), the Interconnect, the Moomba to Sydney Pipeline (MSP), the Roma to Brisbane Pipeline (RBP), the Queensland Gas Pipeline (QGP) and the Victorian Declared Transmission System (DTS)).

In most cases these investments have occurred in response to firm long term commitments by shippers and underwritten by either:

- long term foundation transportation contracts; or
- buyer/producer ownership interests in the pipeline.

In effect, these investments have facilitated the development of a more interconnected network in eastern Australia and, in so doing, increased the supply options available to buyers in most major demand centres.

The current degree of pipeline interconnection in eastern Australia can be seen in Figure 2.1. One point that should be borne in mind when looking at this figure, is that while the current degree of pipeline interconnection means that it is technically feasible to transport gas between a number of basins and demand centres, in practice the ability to move gas between locations will depend on:

- whether there are any capacity constraints on the relevant pipeline(s) or a lack of physical interconnection between pipelines; and
- the extent to which there is any un-contracted capacity on the relevant pipeline(s).

The choice between alternative supply sources will also depend on the costs that would be incurred in transporting the gas from the basin to the demand centre.

Further detail on the ownership, capacity and regulatory status of the major transmission pipelines currently servicing eastern Australia is provided in Table 2.2.[27] Drawing on the information in this table, the following observations can be made about this segment of the supply chain:

- Apart from the DTS, which is operating under a market carriage model, all of the other transmission pipelines in eastern Australia are operating under a contract carriage model. The difference between these two models is explained in Box 2.2 while Box 2.3 provides further detail on how the Victorian market carriage model operates.
- With the exception of the DTS, which is essentially a meshed network with multiple injection points, all of the transmission pipelines operate on a point-to-point basis and are therefore less complex to operate. Potential exceptions to this are point-to-point pipelines with multiple injection and withdrawal points, such as the RBP and the QGP.
- The ownership of gas transmission pipelines is highly concentrated, with APA having an interest in 11 of the transmission pipelines servicing eastern Australia.[28]
- There are only small number of transmission pipelines that are subject to any form of regulation, with three subject to full regulation and another three to light regulation.[29]
- The capacity of the majority of pipelines is heavily utilised on peak days, with five of the 13 pipelines listed in the table utilising over 90% of their rated capacity and another five utilising over 80% of their rated capacity on peak days in 2012. The three exceptions are the SWQP, QSN and the TGP, which were operating at around 50% of their capacity on peak days in 2012.

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27 There are a number of other transmission pipelines in eastern Australia that are not referred to in this table including the Central West Pipeline (CWP), Central Ranges Pipeline (CRP), North Queensland Gas Pipeline, Mildura Pipeline, SESA Pipeline, South East Pipeline, Riverland Pipeline, Barcaldine to Cheepie Pipeline, Dawson Valley Pipeline (DVP), Braemar Linepack Pipeline, Tipton Pipeline, Spring Gully to Wallumbilla Pipeline, Fairview to Wallumbilla Pipeline, Berwyndale to Wallumbilla Pipeline (BWP) and Fairview to QGP Pipeline.

28 In addition to the pipelines listed in Table 2.2, APA has an interest in the CWP, CRP, SESA Pipeline and BWP.

29 The three transmission pipelines that are subject to full regulation are the RBP, DVP and DTS while the three that are subject to light regulation are the MSP between Marsden and Sydney, the CGP and the CWP.

Table 2.2: Major gas transmission pipelines in eastern Australia

	Pipeline	Type of pipeline	Locations serviced	Owner	Regulatory status	Availability of firm capacity as at June 2013	Current capacity (TJ/day)	Utilisation in 2012 (% of capacity)	
								Peak daily demand	Annual throughput
Market Carriage									
Vic	Declared Transmission System (DTS)	Meshed network, with multiple injection points	Longford to Melbourne Pipeline (LMP), Western Transmission System (WTS) and South West Pipeline (SWP). Enables gas to be transported in Vic and to the entry point of the Interconnect	APA	Full regulation	Not applicable because pipeline is operated on a market carriage basis.	LMP 1,030 TJ/day	88%	49%
							SWP 353 TJ/day	~100%	27%
Contract Carriage									
NSW and ACT	Moomba to Sydney Pipeline (MSP)	Point-to-point with two injection points	Extends from Moomba to Sydney, Canberra and Culcairn (the entry point into the Interconnect)	APA	Light regulation btw Marsden and Syd. Unregulated on rest	Firm capacity fully contracted according to spare capacity register.	439 TJ/day	83%	40%
	Eastern Gas Pipeline (EGP)	Point-to-point	Longford to Sydney and Hoskinstown (entry point to Canberra)	Jemena	Unregulated	Firm capacity advertised on website.	294 TJ/day	94%	74%
	Interconnect	Point-to-point and bi-directional	Bi-directional pipeline linking the MSP with the DTS	APA	Unregulated in NSW and regulated in Vic as part of DTS	Firm capacity on NSW side fully contracted.	Northbound: 73 TJ/day Southbound: 90 TJ/day	91%	34%
SA	Moomba to Adelaide Pipeline System (MAPS)	Point-to-point	Moomba to Adelaide	Queensland Investment Corp	Unregulated	Firm capacity available.	241 TJ/day up to 418 TJ/day if mothballed compressors on line	82%	47%
	SEA Gas Pipeline	Point-to-point	Port Campbell (Vic) to Adelaide	APA (50%) and Rest (50%)	Unregulated	Existing firm capacity contracted to Origin, EnergyAustralia and GDF Suez to 2019. SEA Gas advertising availability of an interruptible service.	314 TJ/day	87%	54%
Qld	South West Queensland Pipeline (SWQP) and QSN Link	Point-to-point	Wallumbilla to Moomba. Currently operating in a westerly direction but work underway to convert SWQP to a bi-directional pipeline.	APA	Unregulated	Existing westerly capacity contracted to AGL and Origin. Conversion to a bi-directional pipeline is being underwritten by a contract with Santos	SWQP: 385-404 TJ/day	53%	26%
		Point-to-point					QSN: 250 TJ/day	58%	19%
	Roma to Brisbane Pipeline (RBP)	Point-to-point with multiple injection points	Roma to Brisbane	APA	Full regulation	4 TJ/day firm capacity	233 TJ/day	86%	69%
	Carpentaria Gas Pipeline (CGP)	Point-to-point	Ballera to Mt Isa	APA	Light regulation	3 TJ/day firm capacity	119 TJ/day	94%	84%
	Queensland Gas Pipeline (QGP)	Point-to-point with multiple injection points	Wallumbilla to Gladstone	Jemena	Unregulated	Not reported on Jemena website but unlikely given current utilisation.	145 TJ/day	~100%	88%
Tas	Tasmanian Gas Pipeline (TGP)	Point-to-point	Longford to Hobart	Tasmanian Gas Pty Ltd	Unregulated	Not reported on TGP website but likely given current low utilisation.	129 TJ/day	49%	38%

Sources: Capacity data and utilisation calculations based on information obtained from National Gas Bulletin Board. Information on availability of capacity based on: information contained in APA's spare capacity register http://www.apa.com.au/our-business/economic-regulation/nsw.aspx; Jemena's website (http://jemena.com.au/what-we-do/assets/eastern-gas-pipeline/), SEA Gas' website (http://www.seagas.com.au/access-policy.php) Epic Energy's website (http://www.epicenergy.com.au/index.php?id=32) TGP Pty Ltd's website (http://www.tasmaniagaspipeline.com.au/index.php?option=com_content&view=article&id=48&Itemid=56). All websites accessed on 14 June 2013.

Box 2.2: Contract carriage and market carriage models

Contract carriage model

Under the contract carriage model, the owner of the pipeline manages flows on the pipeline and enters into transportation contracts directly with shippers. Firm capacity contracts are the primary form of transport contract offered by the pipeline. These enable shippers to reserve capacity on a firm basis. New pipeline investment and major pipeline expansions are based on firm long term transport contracts with foundation shippers. These act to allocate pipeline investment risk from the pipeline owner to the shippers.

Market carriage model

The essential features of the market carriage model are:

- A gas scheduling process (based on demand forecasts and injection/withdrawal bids provided by Market Participants (MP)) is used by a market operator to determine the schedules for each MP, which sets out the gas to be injected by each MP at each injection point and to be withdrawn at each withdrawal point.
- The gas scheduling process is used to determine a gas market price which can be used for various purposes (such as trading of imbalances).
- MPs are able to participate in a system of rights that prioritise access to the pipeline at times of congestion and provide pricing signals to gas users. MPs cannot reserve physical point-to-point capacity on the pipeline.
- Investment decisions are made through a regulated process.

Box 2.3: Victorian market carriage model

The rationale for adopting the market carriage model in Victoria can be summarised as follows:

- *It reflects the physical characteristics exhibited by the DTS* - The DTS is essentially a meshed network, with seven injection points (consisting of a number of supply sources and storage facilities), over 120 withdrawal points and a number of pipeline segments that can also operate in a bi-directional manner, depending on demand and supply conditions (see Figure 6.1). The amount of gas that can be stored in the DTS is also quite small and cannot be relied upon to manage significant deviations between demand and contracted supply. LNG storage plays an important role in managing peak day demand. These physical characteristics of the DTS, coupled with the fact that the demand for gas in Victoria exhibits a significant degree of seasonal and daily variability (see Figure 3.1), mean that the DTS must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained. The physical characteristics exhibited by the DTS also mean that it can be very difficult to determine how to define firm capacity rights to shippers.
- *It was expected to support full retail contestability* – The market carriage model and the Declared Wholesale Gas Market (DWGM) was also seen as a way of encouraging new entry by retailers because they would not need to enter into long term gas transportation agreements and they would have equivalent access as incumbent shippers to a mechanism to trade imbalances and purchase gas at the spot price.
- *It was designed to encourage diversity of supply and upstream competition* – The transparency of pricing provided by the DWGM and the operation of the market carriage model were also expected to encourage the development of new sources of supply and upstream competition.

An important feature of the arrangements in Victoria (but arguably not an essential feature of the market carriage model) is an independent market and system operator (AEMO) that operates the pipeline separately from the pipeline owner, and which manages the receipt, transport and delivery of gas as part of the gas market. APA makes the Victorian DTS available to AEMO under a Service Envelope Agreement and makes available a single reference service comprising a Tariff Transmission Service.

The system of rights to prioritise access to the Victorian DTS, is known as Authorised MDQ and AMDQ credit certificate (jointly referred to as AMDQ in the remainder of this report). Amongst other things, AMDQ provides MPs with a hedge against congestion uplift charges up to the nominated Authorised Maximum Interval Quantity (AMIQ) but does not provide any protection against other uplift charges, such as common or surprise uplift.

2.3 Distribution systems

Distribution systems enable gas to be transported under lower pressure from the city gate to users connected to the distribution system. The distribution systems used to transport gas in each of the capital cities in eastern Australia are set out in Table 2.3.[30] As the information in this table reveals, Envestra currently owns three of the distribution systems, Jemena has an interest in two and APA has an equity interest in four, by virtue of its equity stake in Envestra and GDI (EII). Of the distribution systems set out in this table, all but one is currently subject to full regulation.

Table 2.3: Distribution systems servicing capital cities in eastern Australia

Capital city	Pipeline name	Ownership	Regulatory status
Melbourne	Envestra - Vic Distribution System	Envestra (APA 33.65%, CKI 17.8%)	Full regulation
	Multinet - Gas Distribution Network	DUET	
	SP AusNet - Gas Distribution Network	SP AusNet	
Sydney	NSW Gas Distribution Network	Jemena	
ACT	ActewAGL Gas Network	Actew Corporation and Jemena (50:50 joint venture)	
Adelaide	South Australian Distribution System	Envestra (APA 33.65%, CKI 17.8%)	
Brisbane	Allgas Energy Distribution System	GDI (EII) Pty Ltd (APA: 20%, Marubeni: 40%, RREEF: 40%)	
	Envestra Distribution System	Envestra (APA 33.65%, CKI 17.8%)	
Hobart	Tas Gas Networks	Tas Gas (Brookfield Infrastructure)	Unregulated

2.4 Storage facilities

There are a number of dedicated storage facilities located in eastern Australia that are used by buyers and producers to manage peak demand and emergencies, or to otherwise store gas (see Table 2.4). A number of transmission pipelines, such as the MSP, EGP, MAPS and SWQP/QSN, also offer storage services.[31] In addition to these facilities, some gas-fired generators have built dedicated pipeline laterals in close proximity to their plant to store gas.

Table 2.4: Dedicated storage facilities

Storage facility	Ownership	Location
Western underground storage system	EnergyAustralia	Depleted gas field Port Campbell
Moomba and Ballera underground storage facilities	Cooper Basin JV	Depleted fields in Cooper Basin
Silver Springs	AGL	Depleted gas field in the Bowen/Surat basins
Newstead underground storage facility	Origin	
Roma underground storage facility	Santos	
Dandenong LNG storage facility (used in extreme peaks or when there is an emergency outage)	APA	Melbourne
Newcastle LNG storage facility (under development)	AGL	Newcastle

Sources: Core Energy, 2012 GSOO - Gas Facilities, May 2012 and
AGL website, (http://agk.com.au/newcastle/index.php/faqs/) , accessed on 25 May 2013.

30 There are also a number of distribution systems located in regional areas of eastern Australia, including Wagga Wagga, Albury, the Central Ranges, the Central West of NSW, Dalby, Mildura, Loddon Murray and East Gippsland.

31 The term 'storage services' is used in this context to refer to both storage (or 'park') and storage and loan (or 'park and loan') services.

2.5 Direction of gas flows

Estimates developed by EnergyQuest of the gas consumed and produced in 2012 indicate the following:[32]

- Queensland produced all of the gas it consumed in 2012;
- Victoria produced all of the gas it consumed in 2012;
- New South Wales produced just 4% of the gas it consumed in 2012 and imported the remaining 96% from Victoria (56%) and South Australia/Queensland (40%);
- South Australia produced 40% of the gas it consumed in 2012 and imported the remaining 60% from Victoria; and
- Tasmania imported all of its gas from Victoria in 2012.

[32] EnergyQuest, EnergyQuarterly, February 2013, p.100.

3. Demand in Eastern Australian Domestic Market

Historically, the demand for gas in eastern Australia has been relatively stable, growing by just 1.4% pa over the last ten years.[33] All of that is about to change though, with the demand for gas in eastern Australia expected to treble over the next five years when the LNG projects currently under construction in Gladstone come on line. The effect that the LNG projects are expected to have on demand is explored in further detail in the following chapter, while the remainder of this chapter focuses on the demand for gas by the domestic market (ie, excluding LNG exports) and, in particular:

- the nature of the demand for gas by the current group of end-users in eastern Australia;
- the diversity of demand that exists across each jurisdiction in eastern Australia; and
- the outlook for demand by the domestic market.

3.1 Nature of demand

Gas in eastern Australia is currently consumed by:

- residential customers and small to medium sized industrial and commercial customers (SMEs), who tend to purchase their gas on a delivered basis from licenced retailers such as AGL, ActewAGL, Alinta, Aurora Energy, Australia Power and Gas, Dodo Power and Gas, EnergyAustralia, Lumo, [34] Origin, Red Energy,[35] Simply Energy[36] and Tas Gas Retail;
- large industrial customers operating in the mining and manufacturing (eg, aluminium, bricks, cement, fertiliser, petrochemical, paper and steel) sectors, such as Adelaide Brighton Cement, BlueScope Steel, BHP Billiton, Boyne Smelter, BP, Brickworks, Incitec, MMG, OneSteel, Orica, Queensland Magnesia, Queensland Alumina, Rio Tinto, Visy, Xstrata and Zinifex; and
- gas fired electricity generators, such as AGL, Alinta, Arrow, Braemar Power Project, CS Energy, EnergyAustralia, Ergon Energy, Delta Electricity, ERM Power, GDF Suez, Hydro Tasmania, Industry Funds Management Nominees Ltd, Origin, Pelican Point Power, QGC, Snowy Hydro, Stanwell, Synergen Power and Smithfield Power Partnership.

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33 Based on EnergyQuest's estimate of the gas consumed in eastern Australia in 2012 (722 PJ) and the Bureau of Resource Energy Economics' (BREE) estimate of the gas consumed in 2002. *See* BREE, Australian energy consumption by industry and fuel type 1974-75 to 2010-11, Table F and EnergyQuest, EnergyQuarterly, February 2013.

34 Simply Energy is the retail arm of GDF Suez.

35 Lumo is the retail arm of Infratil.

36 Red Energy is the retail arm of Snowy Hydro.

The volume of gas consumed by these groups of end-users and the pattern of their consumption during the year will depend on their end-use requirements and, in some cases, their location. For example:

- The consumption profile of residential customers that live in areas subject to a distinct seasonal influence (eg, Victoria and Canberra) is likely to be quite volatile in the winter months given the reliance placed on gas fuelled heating, whereas the consumption profile of the same group of customers living in more temperate climates (eg, Brisbane) is likely to be relatively flat because gas is predominantly used for cooking.
- Large industrial customers that have stable demand for their end products and use a relatively constant production process are likely to have a relatively flat consumption profile.
- Mining companies that are exposed to international commodity markets may have quite a lumpy consumption profile over time, as output changes in response to changing conditions in the commodity markets.
- A base-load or intermediate gas fired generator (CCGT) is likely to have a relatively flat consumption profile, while a peaking generator (OCGT) is likely to have a more volatile consumption profile.

Two other factors that will influence the nature of these end-users' demand for gas, are:

- the level of investment they need to undertake to use gas in their operations, or for retailers the length of their contractual commitments to supply gas; and
- their ability to switch to alternate fuels, which will only be relevant to some end-users.

Understanding the differences in the nature of demand that can exist across buyers and locations is critical to understanding:

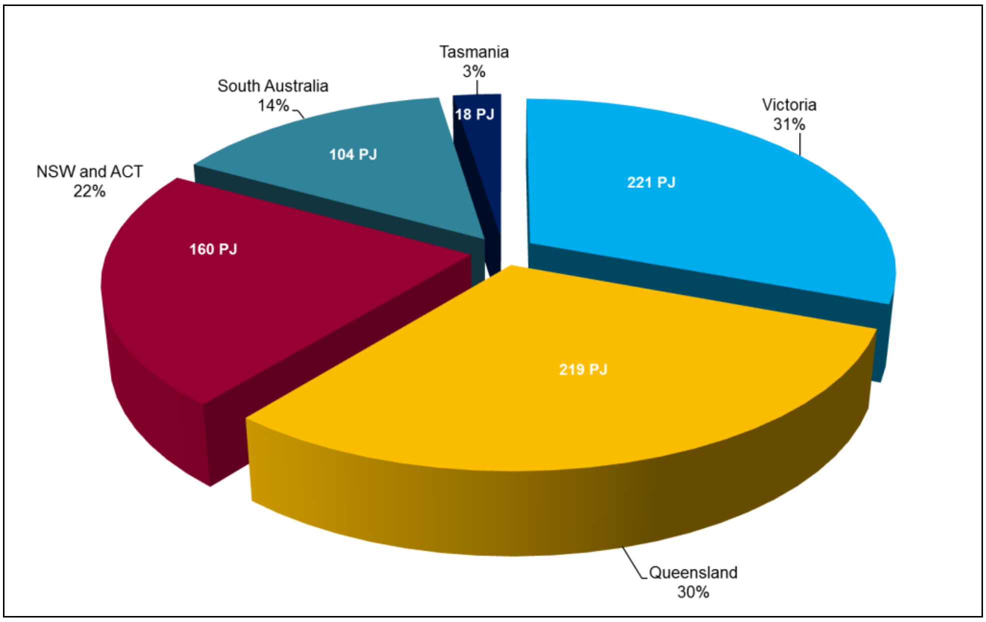
- the types of gas supply and transportation contracts that buyers are likely to enter into (eg, firm vs 'as available', short, medium or long term contracts);
- the need that some buyers may have to use volume related risk management tools, such as storage facilities, imbalance markets or flexible contract provisions; and
- the ability of parties to enter into secondary trades of gas and/or pipeline capacity.

These issues are explored in further detail in section 5.7.

3.2 Diversity of demand across the jurisdictions

The demand for gas in eastern Australia over the last ten years has increased by approximately 15% (~1.4% pa), from around 625 PJ[37] in 2002 to 722 PJ in 2012.[38] The majority of the growth experienced over this period occurred in Queensland, with demand in this state more than doubling between 2002 and 2012. In other jurisdictions, the growth in demand for gas has been less pronounced and, in the case of South Australia has been stagnant. A breakdown of the gas consumed by each jurisdiction in 2012 is provided in Figure 3.1.

Figure 3.1: Gas consumption by jurisdiction in 2012 (722 PJ)



Source: EnergyQuest, EnergyQuarterly, February 2013.

As the information in this figure reveals, Victoria and Queensland are currently the largest consumers of gas in eastern Australia, accounting for 31% and 30%, respectively of the 722 PJ consumed in 2012. Across the remaining jurisdictions, NSW and the ACT consumed 22%, South Australia 14% and Tasmania 3%.

Further insight into the sources of demand in each jurisdiction can be found in Figure 3.2, which provides an industry based breakdown of the gas consumed in 2011.

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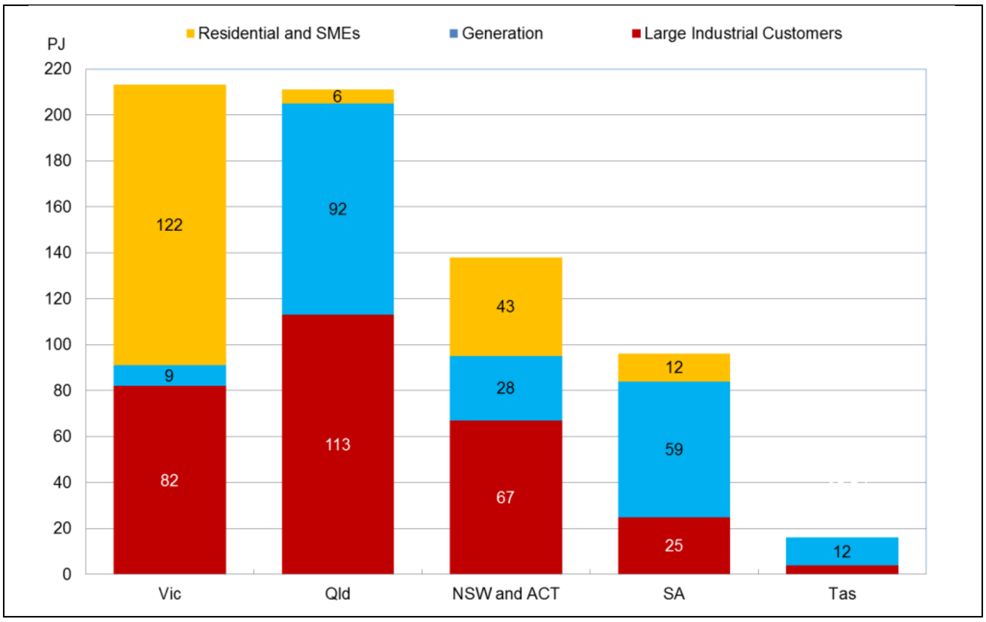
37 BREE, Australian energy consumption by industry and fuel type 1974-75 to 2010-11, Table F.

38 EnergyQuest, EnergyQuarterly, February 2013.

Figure 3.2: Gas consumption by industry and jurisdiction (2011)



Source: AEMO, 2012 GSOO, Appendix A-1.

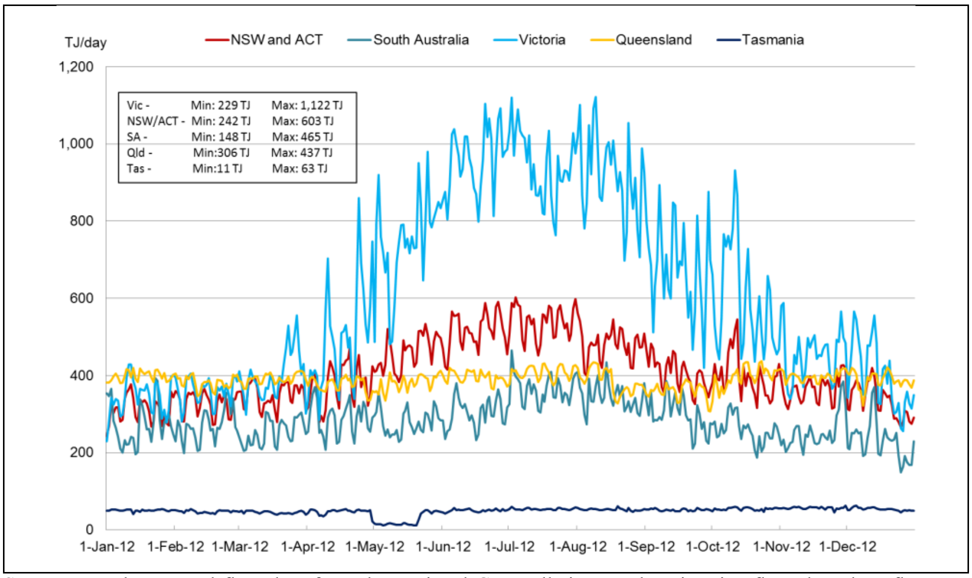
Based on the information contained in this figure, it is apparent that large industrial customers and gas fired generators currently account for the majority of the gas consumed in eastern Australia, with 73% of the gas consumed in eastern Australia in 2011 accounted for by these sectors (large industrial: 43% and gas fired generation: 30%). The remaining 27% was consumed by residential and SMEs.

On a jurisdictional basis:

- gas fired generators accounted for the greatest proportion of gas consumed in 2011 in both South Australia (61%) and Tasmania (75%);
- large industrial customers were the largest consumers in Queensland (54%) and NSW/ACT (49%); and
- residential customers and SMEs were the largest consumers of gas in Victoria (57%).

Another interesting point to note from Figure 3.2 is just how different the scale of residential and SME consumption is in each jurisdiction, with consumption from this group ranging from less than 1 PJ to 120 PJ across eastern Australia. As Figure 3.2 indicates, Victorian residential and SME consumers were the largest (122 PJ), followed in declining order by NSW (43 PJ), South Australia (12 PJ), Queensland (6 PJ) and Tasmania (less than 1 PJ). The marked difference in the volume of gas consumed by this group in each jurisdiction goes some way to explaining the difference in the variability of demand observed in eastern Australia, as illustrated in Figure 3.3.

Figure 3.3: Variability of demand in 2012



Source: Based on actual flow data from the National Gas Bulletin Board. Victorian flows based on flows on Longford to Melbourne and South West Pipeline, NSW and ACT flows based on flows on the EGP, MSP and Camden, South Australian flows based on flows on the MAPS and SEA Gas Pipeline and Queensland flows based on flows on the RBP, QGP and CGP.

As Figure 3.3 highlights, the demand for gas in Victoria is far more variable than it is in other jurisdictions and exhibits a distinct seasonal trend, with demand ranging from 230 TJ/day in January 2012 to over 1,100 TJ/day in July 2012. This degree of variation is not surprising given residential heating load accounts for such a significant portion of demand in the state and there are more than 1.8 million residential gas customers in Victoria.[39] Across the other jurisdictions:

- NSW/ACT's consumption profile exhibits a reasonable degree of variability and, like Victoria, has a distinct seasonal trend, with demand peaking in winter and reaching its lows in summer. This variability appears to reflect the effect of heating load, with residential and SME customers accounting for around 30% of demand in NSW/ACT.
- South Australia's consumption profile also exhibits a reasonable degree of variability, but rather than just peaking in winter it also peaks in summer. The prevalence of gas fired generation in South Australia, coupled with the fact that electricity demand in South Australia has tended to peak in summer, would appear to explain this profile.
- Queensland's consumption profile is relatively flat, which is consistent with the fact that its largest group of end-users, large industrial customers, tend to have a relatively flat load profile. In terms of gas fired generation, which also accounts for a significant portion of Queensland's demand, 59% of the gas consumed by Queensland generators in 2011 was consumed by CCGT plants while another 40% was consumed by OCGT plants that were operating more like base-load to intermediate plants than peaking plants.[40]
- Tasmania's consumption profile is usually[41] relatively flat, which is consistent with the fact that the Tamar Valley CCGT accounts for most of the gas consumed in the state.[42]

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39 ESC, Energy Retailers Comparative Performance Report – Pricing 2011-12, September 2012, p14.

40 Observation based on information contained in Table 56 (NEM gas-fired generation and gas use) of EnergyQuest's February 2013 EnergyQuarterly. The two OCGT plants referred to in this context were Braemar Power and Braemar 2.

41 In May 2012 demand fell to 11 TJ/day before returning to its usual level of 40-60 TJ/day in June 2012.

3.3 Outlook for demand by the domestic market

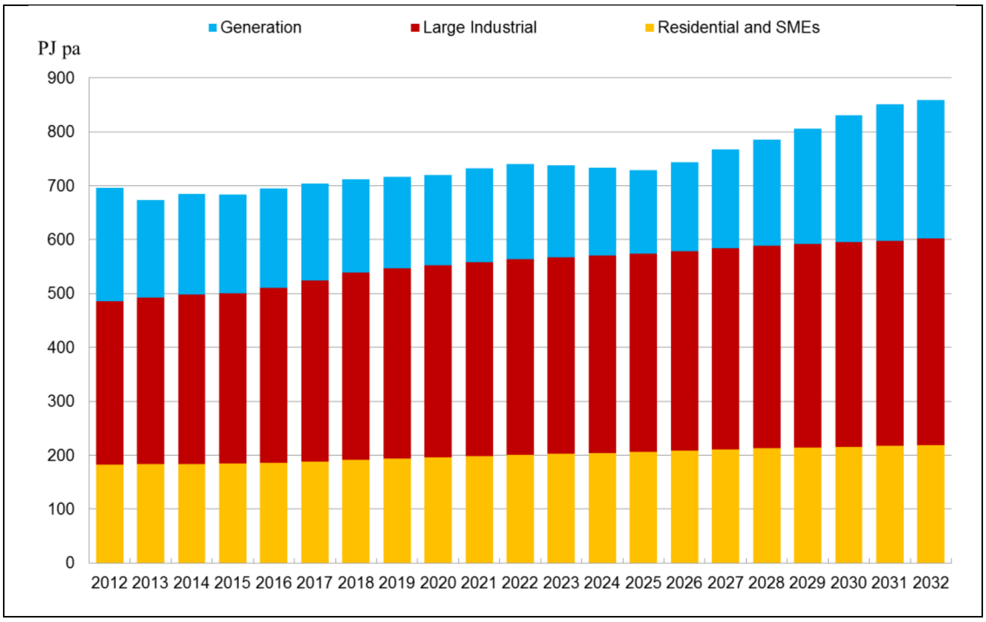
AEMO's latest 'planning scenario' demand projections are set out in its 2012 Gas Statement of Opportunities (GSOO) and are reproduced in Figure 3.4. Before examining these projections, it is worth noting the planning scenario assumes the following:[43]

- medium economic growth;
- a 5% carbon reduction target;
- gas prices ranging from $4.71 to $12.38/GJ; and
- stable international coal prices.

On the basis of these assumptions, AEMO has projected that the demand for gas by the eastern Australian domestic market will: [44]

- increase by just 3% (~0.4% pa) between 2012 and 2020, with most of the growth driven by large industrial customers;
- remain relatively steady between 2020 and 2025, with large industrial customers' demand continuing to increase while gas fired generators' demand rises and then falls; and
- rise by 18% (~2.4% pa) between 2025 and 2032. The principal driver of growth in this period is gas fired generation, with demand from this group expected to increase by 66%. It is worth noting in this context that AEMO's projections assume that no new gas fired generation will be required in eastern Australia until around 2025.

Figure 3.4: AEMO – gas demand projections (planning scenario)



Source: AEMO, Gas Statement of Opportunities, 2012, Figure 1.

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42 Observation based on information contained in Table 56 of EnergyQuest's February 2013 EnergyQuarterly.

43 AEMO, Gas Statement of Opportunities, 2012, p.1-4.

44 AEMO, Gas Statement of Opportunities, 2012, Figure 1.

Although not shown in Figure 3.4, AEMO's planning scenario projections assume the following about the demand for gas in each jurisdiction between 2012 and 2020:[45]

- Queensland – demand is expected to *rise* by 17%;
- NSW and ACT – demand is expected to *rise* by 10%;
- Victoria – demand is expected to *rise* by 2%;
- South Australia – demand is expected to *contract* by 33%; and
- Tasmania – demand is expected to *contract* by 4%.

In Victoria, South Australia and Tasmania, the change in demand is expected to be primarily driven by changes in gas fired generators' consumption, while in NSW/ACT and Queensland the growth in demand is expected to be driven by large industrial customers.

To put AEMO's planning scenario projections into context, they are:

- broadly in line with the domestic demand projections recently developed by ACIL Tasman through to 2019, but from 2020 are lower than ACIL Tasman's;[46] and
- substantially higher than the projections recently developed by EnergyQuest, with EnergyQuest projecting that over the period 2014-2017 domestic demand will fall by about 100 PJ pa as a result of higher gas prices, the cessation of the Queensland Gas Scheme and the continued expansion of renewable energy sources.[47]

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45 AEMO, Gas Statement of Opportunities, 2012, Figure 3.3 and 3.4.

46 ACIL Tasman, Draft cost of gas for the 2013 to 2016 regulatory period, 22 April 2013, p.16.

47 EnergyQuest, EnergyQuarterly, May 2013, p.25 and AFR, Dim Future for Gas Supply, 27 May 2013.

4. Changes Underway in Eastern Australia

The eastern Australian gas market is currently undergoing a number of fundamental demand- and supply-side changes, the most significant of which are being driven by the development of LNG facilities in Queensland. Other developments that are expected to affect, to varying extents, the demand-supply balance and gas prices going forward include:

- the proposed development of a number of new sources of supply in the Bowen/Surat, Cooper, Gippsland, Gunnedah and Gloucester basins; and
- climate change policies and the conditions in National Electricity Market (NEM).

The remainder of this chapter provides further detail on each of these developments and outlines how they are expected to affect the demand-supply balance and gas prices in eastern Australia. It also provides an overview of the Commonwealth Government's longer term vision for the eastern Australian gas market and reviews that are either underway or have recently been completed.

4.1 LNG developments

The announcement by Arrow Energy[48] in May 2007 that it was considering developing an LNG facility in Queensland heralded the commencement of a new era in the eastern Australian gas market. Soon after Arrow's announcement, a number of other prominent players, such as Santos, Origin and BG, announced they too were considering developing LNG facilities at Gladstone that would be supplied from their respective CSG interests in the Bowen/Surat basins.[49] In the period that has followed, a considerable amount of work has been carried out to progress these projects and while no LNG facilities are yet operational, they are already having a significant influence on the conditions prevailing in the market.

The influence these developments are having on the market is not surprising given:

- *the scale of the projects that are currently being developed* – the combined capacity of the QCLNG, GLNG and APLNG projects is 25.3 mtpa (~1,550 PJ pa) [50] and on an aggregate basis the three projects are expected to cost over $64 billion to construct.[51] To put the scale of these projects into perspective, it is worth noting that:
  - the capacity of the three projects *exceeds* the combined capacity of the existing LNG projects in Australia (ie, the North West Shelf LNG project (16.3 mtpa), the Bayu-Undan Darwin LNG project (3.5 mtpa) and the Pluto project (4.3 mtpa)); and

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48 Arrow, Arrow Executes LNG Export HOA for Gladstone LNG Facility, 30 May 2007.

49 Santos, Santos proposes multi-billion dollar Gladstone LNG Project, 18 July 2007, Origin, Origin selects ConocoPhillips to acquire a 50% share in a CSG to LNG Joint Venture for up to A$9.6 billion, 8 September 2008 and Presentation, 8 September 2008 and QGC, QGC Announces $870 million alliance with BG Group for LNG development, 3 February 2008.

50 This estimate includes a 10% fuel allowance.

51 EnergyQuest, EnergyQuarterly, May 2013, pp. 60-68.

- the reserves required to supply the projects over a 20 year period is over 31,000 PJ, while the annual gas requirement is around 1,550 pa, which is 2.2 times *greater* than the gas that was supplied to end-users in eastern Australia in 2012.

▪ *the short period of time over which the projects are to become operational* – initial supply from QCLNG's facility is due to commence in late 2014 while supply from GLNG and APLNG's facilities is due to commence in 2015. While the infrastructure side of these developments appears to be progressing in line with project timelines, some proponents have experienced difficulties developing the productive capacity of their fields in time[52] and have decided to:

  - enter into gas supply agreements with other producers to supplement their production. For example, GLNG has entered into a 15 year 750 PJ contract with Santos and a 10 year 365 PJ contract with Origin[53] while QCLNG[54] has entered into a three year contract for 54-74 PJ[55] with AGL and a 640 PJ[56] contract with APLNG involving the supply of gas from their joint tenements; and
  - ramp up to full capacity after the facilities are commissioned rather than in the lead up to commissioning. For example, while the QCLNG facility is expected to start exporting at the end of 2014, it is not expected to ramp up to full production until 2016. GLNG's second train is also expected to take time to reach full capacity.[57]

▪ *the potential for new LNG facilities to be developed[58] or existing facilities expanded* – while the likelihood of this occurring in the short to medium term has diminished with the emergence of the US as a potential competitive source of LNG, there is still a possibility over the medium to longer term that the facilities under construction will be expanded, or additional facilities, such as Arrow LNG's proposed 8 mtpa facility, will be developed (either on a stand-alone basis or as part of one of the existing projects).[59]

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52 The challenges faced by LNG proponents in building up the productive capacity of their fields were outlined in an article in *The Australian* on 24 February 2012 entitled, *Origin warns of gas squeeze: Producer defies fears of glut*.

> "ORIGIN Energy boss Grant King says Queensland's burgeoning coal-seam gas export industry may struggle to drill enough of the thousands of onshore wells needed to meet the early demands of multi-billion-dollar plants being built at Gladstone, highlighting a tightening of a market some feared would be in a glut.
>
> The managing director said whereas previously the industry had feared Queensland would be awash with gas as onshore production ramped up to feed Gladstone's liquefied natural gas, there was now the possibility that drilling could fall short.
>
> ``I think we will enter another paradigm where, in aggregate, not only will the industry be able to manage the ramp-up but probably it's going to be a bit challenged to deliver the aggregate resource," Mr King told The Australian.
>
> While all three under-construction Gladstone plants that will freeze the gas and transfer it to ships bound for Asia were on track, the huge effort needed to get all the onshore gas wells up and going had been affected by flooding in Queensland over the past two years, he said."

53 Santos, Santos to supply 750 PJ of portfolio gas to GLNG, 25 October 2010 and Origin, Origin announces major gas sales agreement with GLNG, 2 May 2012.

54 See also The Age, British Gas aims to build volumes, 31 July 2013, which suggests that BG is negotiating a number of other third-party gas supply agreements.

55 AGL, 2011 Full Year Results 12 mths to 30 June 2011, slide 34.

56 EnergyQuest, EnergyQuarterly, May 2013, p.63.

57 EnergyQuest, EnergyQuarterly, May 2013, pp. 65 and 68.

58 Two other facilities that have been proposed include Arrow LNG's proposed 8 mtpa facility and LNG Ltd's proposed 3 mtpa facility.

59 The date for making a final investment decision on the Arrow LNG project has reportedly been pushed back to the end of 2013. It is worth noting though that Arrow LNG is reportedly in talks with both GLNG and APLNG, so it is possible

Table 4.1 provides further detail on the three projects currently under construction.

Table 4.1: LNG projects under development

Project proponent	QCLNG	GLNG	APLNG
JV Participants	BG, CNOOC and Tokyo Gas	Santos, Petronas, Total and KOGAS	Origin, ConocoPhillips and Sinopec
Size and annual gas requirements[1]	2 trains (8.5 mtpa) ~520 PJ pa	2 trains (7.8 mtpa) ~475 PJ pa	2 trains (9 mtpa) ~550 PJ pa
	Potential for a third train (3.5 mtpa) to be developed but no decision has yet been made.	*Potential for a third train (2.2 mtpa) but unlikely at this stage given the difficulties experienced to date in securing reserves and US developments.*	*Potential for another two trains (9 mtpa) but unlikely at this stage given statements by project proponents and US developments.*
Expected start date[2]	1st train late 2014 and 2nd train 2015. Production to ramp up to full capacity by 2016.	1st train 2015 and 2nd train 6-9 months later. Production to ramp up to full capacity by 2019.	1st train mid- 2015 2nd train late 2015
Other infrastructure	340 km pipeline and LNG plant and port facility at Curtis Island.	420 km pipeline and LNG plant and port facility at Curtis Island.	360 km pipeline and LNG plan and port facility at Laird Point Curtis Island.
Buyers	CNOOC (3.6 mtpa) and Tokyo Gas (1.2 mtpa)	Petronas (3.5 mtpa) and KOGAS (3.5 mtpa)	Sinopec (7.6 mtpa) and Kansai Electric (1 mtpa)
Third party gas supply agreements	54-74 PJ 3yr GSA with AGL 640 PJ GSA with APLNG from joint tenements	750 PJ 15 yr GSA with Santos 365 PJ 10 yr GSA with Origin	n/a

Notes and Sources: 1. These estimates include a 10% allowance for fuel gas and pipeline losses. 2. EnergyQuest, EnergyQuarterly, May 2013, pp. 60-68. EnergyQuest, EnergyQuarterly, May 2013, pp. 69 and 72.

With production in eastern Australian having to treble over the next three to five years (ie, from 722 PJ to over 2,200 PJ) to satisfy both domestic and export demand, and some LNG proponents having to supplement their own production with supply from other sources, conditions in the market are understandably tight at this point in time. The manner in which these tight conditions are manifesting themselves can be summarised as follows:

- Convergence toward LNG netback prices (see Box 4.1) is occurring more rapidly than expected, with a number of new contracts reportedly having been entered into that are either linked to an oil price benchmark[60] or set at a level consistent with an LNG netback price.[61]
- The effects of the convergence toward LNG netback prices are being felt beyond the

the Arrow LNG project will be combined with one of these existing projects. See EnergyQuest, EnergyQuarterly, May 2013, p.70 and AFR, Origin and Arrow in talks over LNG project, 27 May 2013.

60 For example, in April 2013 Origin announced that it had entered into a conditional agreement with Beach Energy to purchase up to 17 PJ pa from Beach Energy's interests in the Cooper Basin over an eight year period (with a two year extension option) commencing in 2015. According to Origin's media release, the price specified in this contract is linked to oil and other parameters. In May 2013 Lumo also announced that it had entered into a new gas supply agreement with the Gippsland Basin JV, which would involve the supply of 22 PJ of gas over a three year period commencing in 2015. According to Infratil's media release, the price specified in this contract is linked to oil.

See Origin, Origin expands east coast portfolio with agreement to purchase gas from Beach Energy, 10 April 2013 and Infratil Ltd, Lumo Energy signs gas sales agreement, 14 May 2013.

61 For example, MMG has reportedly entered into a new gas supply agreement with Origin in December 2012 that will step up to $9/GJ once the LNG plants come on line. The Australian, Origin Energy secures record gas price, 21 December 2012.

borders of Queensland, with new contracts involving producers in both the Cooper and Gippsland basins reportedly being linked to oil prices.[62]

- Some buyers in Queensland have reportedly found it difficult to find producers willing to enter into new long term gas supply agreements.[63]
- Consideration has reportedly been given to transporting gas from Victoria to Queensland to either supply the LNG projects or domestic customers in the region. Given the distance this gas would be transported and the costs involved, this is a significant potential development, which could have broader reaching implications for pipeline utilisation in eastern Australia.

Box 4.1: LNG netback prices

The term 'LNG netback price' is used to describe the equivalent price a producer could receive at a particular location if it was to export gas to an LNG customer, once the costs of transportation, shipping and liquefaction costs are taken into account. It may therefore be viewed as an export parity price.

The LNG netback price can differ depending on:

- the oil price benchmark used in the calculation of the price paid for LNG (typically the Japanese Crude Cocktail (JCC) price) and the assumed relationship between the oil price benchmark and the LNG price (known as the slope);
- the assumption made about the costs of liquefaction and any other costs associated with the processing the gas; and
- the transportation costs assumed to be incurred in delivering the gas to the LNG facility, which will depend on the location of the producer. For example, if the producer is located in the Gippsland Basin then the transportation cost component of the LNG netback price will be substantially higher than if the producer was located in the Bowen/Surat basins. The LNG netback price at the Gippsland Basin will therefore be lower than the LNG netback price at Wallumbilla.

The LNG netback price can also vary over time as the underlying oil price benchmark moves.

Estimates recently developed by EnergyQuest of the LNG netback price at Moomba under an assumed JCC price of US$100-$120/bbl (where JCC prices have ranged for the last 12 months), range from $7.41/GJ to $9.90/GJ.[64]

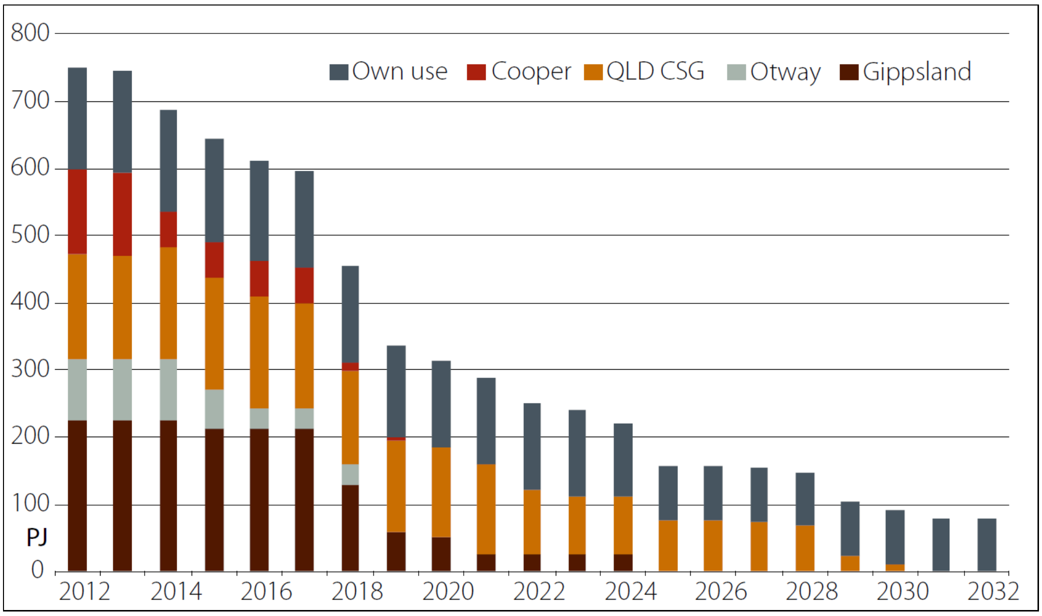
[62] See footnote 60.

[63] See for example, Department of Energy and Water Supply, Gas Market Review Queensland, 2012, p.38 and The Australian, Clash looms as supply contracts unsecured, 19 January 2013.

[64] EnergyQuest, *Energy Quarterly*, May 2011, p.88.

Looking forward, conditions are expected to continue to tighten in the market when the LNG facilities come on line and start ramping up to full capacity. The period over which this is to occur, coincides with the time at which a large number of domestic gas supply contracts are due to expire (ie, between 2015 and 2017 – see Figure 4.1).[65] The market is therefore likely to be placed under additional pressure over the next three to five years as domestic customers whose contracts are due to expire compete with each other, and potentially LNG proponents, to secure supply from a much smaller set of producers.

Figure 4.1: Expiration of domestic gas supply contracts



Source: Original source – EnergyQuest but reproduced by BREE in Gas Market Report, July 2012, p.50.

4.2 Potential development of new sources of supply

As the information in Figure 2.3 reveals, there are enough reserves in eastern Australia to satisfy domestic demand for some years to come. The critical question at this stage is not, however, whether there are sufficient reserves. Rather, the question is whether the reserves can be developed in time to address the shortfall in supply that is expected to arise once the LNG projects start exporting, and to counter the projected decline of the Otway Basin, which is expected to occur from around 2019.[66]

Some of the new sources of supply that have been proposed in eastern Australia include:

- The **Kipper** field in the **Gippsland Basin,** which is jointly operated by BHP, ExxonMobil and Santos. A final investment decision was made to proceed with the

[65] According to the 2012 Queensland Gas Market Review, the majority of large buyers in Queensland will need to recontract for all or part of their load in 2015 and 2016 while in the remainder of eastern Australia recontracting is expected to occur in 2018. This observation is consistent with observations made by others including AGL and SKM. *See* Queensland Department of Energy and Water Supply, 2012 Gas Market Review, p.23, AGL, Macquarie Australia Conference, 2 May 2013, slide 14 and SKM, Gas Market Modelling for the Queensland 2011 Gas Market Review, 29 July 2011, p.93.

[66] EnergyQuest, EnergyQuarterly, May 2013, p.25.

development of this field in 2007 but the commencement of supply has been delayed because trace levels of mercury have been found in the reservoir. It is currently expected to come on line in the first half of 2016.[67]

- The **Gunnedah Basin**, which is located in the north-west slopes and plains region of NSW and consists of a number of coal seam gas fields (including in the Pilliga Forest area) that are jointly owned by Santos and EnergyAustralia. Santos and EnergyAustralia are yet to sanction the development of this basin, but Santos has indicated that if a decision is made to proceed, supply could commence by 2017.[68] If such a decision is made, then environmental approvals will need to be obtained[69] and a new transmission pipeline will need to be constructed to enable the gas to be supplied into south eastern Australia and/or Queensland. A significant investment in upstream production and pipeline facilities will therefore need to be made to bring this source of supply on line.

- The **Gloucester Basin**, which is located north of Newcastle and consists of a number of fields that are operated by AGL. AGL is yet to make a final decision to develop the Gloucester Basin, but has indicated that if a decision is made to proceed then supply could commence in late 2016.[70] In a similar manner to the Gunnedah Basin, the development of this basin will require the construction of a new transmission pipeline linking the Gloucester Basin to Hexham, one of the entry points to Jemena's NSW Gas Distribution Network. The development of the Gloucester Basin will therefore require significant investment in both upstream production and pipeline facilities. In February 2013 AGL obtained the environmental approvals required to develop the first stage of this project, which includes the development of a 96 km pipeline to Hexham.[71]

- The **Ironbark field** in the **Bowen/Surat basins**, which is operated by Origin. This project is still in the exploration stage but Origin has sought environmental approval for the development. If the field is developed, a new pipeline will need to be constructed and significant upstream investment will also be required. At this point in time, supply from Ironbark is expected to occur between 2015 and 2016.

- Unconventional[72] forms of gas supplied from the **Cooper Basin**. Over the last two years, Beach Energy, Santos, Drillsearch and Senex, have taken steps to establish the scale of

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67 EnergyQuest, EnergyQuarterly, May 2013, p.56.

68 Santos, Macquarie Australia Conference, 1 May 2013, slide 4.

69 It is worth noting that Santos has recently announced it has submitted an exploration program proposal for the Pilliga exploration program to the Commonwealth Government for assessment under the Environment Protection Biodiversity Conservation Act. Santos, Santos seeks approval for Pilliga exploration program, 28 June 2013.

70 AGL website (http://agk.com.au/gloucester/index.php/the-project/) and EnergyQuest, EnergyQuarterly, May 2013, p.74.

71 AGL, AGL receives Commonwealth approval for the Gloucester Gas Project, 12 February 2013.

72 Unconventional sources of natural gas are found in low permeability formations (such as coal seams, shale and tight sands) and therefore require alternative methods to those employed for conventional natural gas extraction. The two commonly referred to forms of unconventional gas are shale and tight gas. Shale gas is found in low permeability shale formations while tight gas is found in low-porosity sandstones and carbonate reservoirs.

unconventional resources in the Cooper Basin.[73] However, a decision is yet to be made to proceed with the commercialisation of any of these resources. There is therefore some uncertainty surrounding the time at which these unconventional forms of gas are likely to be made available to the market, if they are found to be commercially viable to develop. In the most recent Queensland Gas Market Review, it was assumed that significant volumes of shale gas would not be produced before 2020.[74]

- Unconventional and conventional forms of gas supplied from Armour Energy's interests in the **South Nicholson** and **Isa Super Basins** in Northern Territory and north-west Queensland. Referred to as the Northern Area Gas Scheme Project, this development is still in exploration stages and reserves are yet to be certified. Armour Energy has, however, recently announced it is targeting February 2016 for the delivery of first gas and has entered into a conditional Heads of Agreement with APA to build a 350 km pipeline that would initially enable 130 PJ pa of gas to be transported from its fields to Mt Isa and then use existing (potentially expanded) pipeline infrastructure to be transported into other parts of eastern Australia.[75]

Further detail on these potential new sources of supply is provided in Table 4.2. Before examining this table, it is worth noting that the list of potential new sources has diminished somewhat following the introduction of the NSW Government's Strategic Regional Land Use Policy (see Box 2.1), with a number of projects (accounting for at least 570 PJ[76] of reserves) now on hold including: Metgasco's Clarence-Moreton Basin project; Dart Energy's Fullerton Cove project; AGL's Hunter gas project and its proposed expansion of Camden.[77]

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73 See for example, Beach Energy, Investor presentation, March 2013, Santos, UBS Australian Resources & Energy Conference, 13 June 2013, Senex, Major new conventional gas field identified at Hornet, 15 May 2013 and Drillsearch, Investor Presentation, March 2013.

The shale gas developments in the Cooper Basin have attracted the interests of a number of other players that have formed joint ventures with the original proponents. For example, BG and Drillsearch have formed a joint venture and Chevron has recently farmed into some of Beach Energy's exploration acreage.

74 Intelligent Energy Systems, Modelling and Analysis for the Gas Market Review 2012, 12 June 2012, p.37.

75 Armour Energy Ltd, Heads of Agreement with APA Group for gas transportation services, 26 June 2013.

76 This estimate only includes Metgasco's reserves in the Clarence-Moreton Basin and AGL's reserves in the Hunter region. While it is understood that the policy has also resulted in AGL suspending the expansion of its Camden project, it is unclear what the quantum of reserves are at risk so these have been excluded. This estimate also makes the conservative assumption that the Gloucester and Gunnedah basin projects will be unaffected by the policy. The reserve estimates are based on information contained in EnergyQuest, EnergyQuarterly, May 2013.

77 See Metgasco, Suspension of Metgasco's Clarence Moreton program, Newcastle Herald, Dart's Fullerton Cove field operations suspended, 2 April 2013 and EnergyQuest, EnergyQuarterly, May 2013, p.74.

Table 4.2: Potential new sources of supply

Project (proponent)	Reserves as at May 2013[1]	Est. annual production (PJ pa)[1]	Potential start date[3]	Pipeline infrastructure
Kipper field (Gippsland Basin) (BHP, ExxonMobil and Santos) *FID made but commencement delayed*	622 PJ	30 PJ	2016[1]	Can utilise existing transmission pipelines servicing Gippsland Basin (eg, EGP, DTS)
Gunnedah Basin (Santos and EnergyAustralia) *Exploration stage so no FID has yet been made and no environmental approvals have been obtained*	1,426 PJ	Initial target 36.5 PJ[2]	2016-17[2]	For gas supplied to south eastern Australia: a new 170 km pipeline will need to be constructed linking Narrabri and either the Central Ranges Pipeline (CRP) or the MSP For gas supplied to Queensland: a new 470 km pipeline will need to be constructed linking Narrabri and Wallumbilla [4]
Gloucester Basin (AGL) *FID not yet made but environmental approvals obtained*	669 PJ	30 PJ	2016[1]	A new 96 km pipeline will need to be constructed linking the production facility at Stratford with Jemena's NSW Gas Distribution Network at Hexham[5]
Ironbark field (Bowen/Surat basins) (Origin) *Exploration stage so no FID has yet been made but environmental approvals have been sought*	178 PJ	20-40 PJ	2015-2016	A new pipeline will need to be constructed linking the field to the existing infrastructure servicing the Darling Downs Power station
Cooper Basin (Beach/Chevron, Santos, Senex, Drillsearch/BG) *Exploration stage only so no FID has yet been made*	No reserves certified but contingent resource estimated to be 4,358 PJ	n/a	n/a	Can utilise existing transmission pipelines servicing the Cooper Basin (eg, MSP, MAPS and QSN/SWQP.
South Nicholson and **Isa Super basins** (Armour Energy) *Exploration stage only so no FID has yet been made*	No reserves certified and currently establishing contingent resources	130 PJ-200 PJ[6]	2016	A new 350 km pipeline will need to be built to connect fields to Mt Isa and can then use existing infrastructure to supply remainder of eastern Australia

Sources: 1. EnergyQuest, EnergyQuarterly, May 2013. 2. Santos, Natural Gas – A balanced energy solution for NSW, 10 April 2013, slide 11. 3. Santos, Macquarie Australia Conference, 1 May 2013, slide 4. 4. Santos, 2012 Investor Seminar, 22 November 2012, slide 91. 5. AGL, Gloucester Gas Project Environmental Assessment, November 2009, figure 1.1. Santos, APPEA Investor Briefing, 28 May 2013 refers to accelerated development of unconventional sources from 2016 onward. 6. Armour Energy Ltd, Heads of Agreement with APA Group for gas transportation services, 26 June 2013.

While it is possible these new sources of supply may fill some[78] of the void left by the LNG developments, it is unclear at this stage whether:

- all of the projects will proceed given that only one has passed the final investment stage;
- those projects that do proceed will be used to supply the domestic or export market; and
- the projects that do proceed and are directed toward the domestic market will be able to be brought on rapidly enough to ameliorate the supply shortfall expected to arise when existing domestic contracts start to expire and the LNG projects start to ramp up.

A considerable degree of uncertainty therefore currently surrounds whether these proposals will be able to ameliorate the supply shortfall that is expected to arise once the LNG proponents start directing gas away from the domestic market to their LNG facilities.

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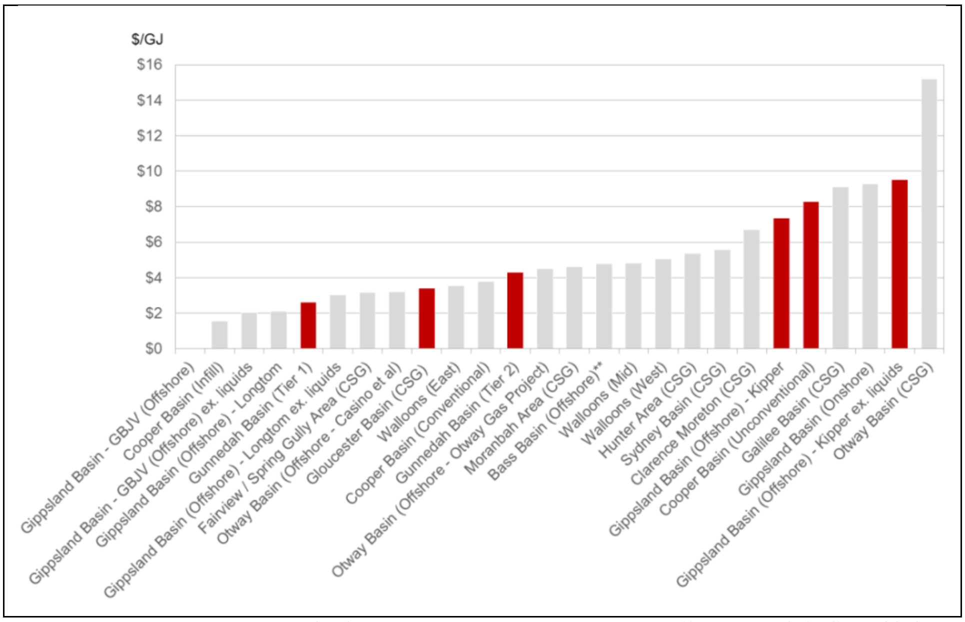
[78] Note that it is possible that some of the supply shortfall may also be met by increased production from existing fields/basins. For example, if the Gippsland Basin JV was able to reduce its commitment to meet peak demand in winter (ie, by entering into contracts with lower load factors), it could increase output over the remainder of the year.

One other point worth highlighting in this context is that a number of the projects listed above are expected to incur higher production costs than existing sources of supply (see for example Core Energy's estimates in Figure 4.2).[79] Gas prices are not therefore expected to fall back to historic levels of \$3-\$4/GJ,[80] unless new cheaper sources of gas are identified or production costs fall.

Figure 4.2: Core Energy's estimates of supply costs by basin



Source: Core Energy, Gas Production Costs, 2012 AEMO GSOO, 26 April 2012. Red shading added.

4.3 Climate change policies and conditions in the NEM

The carbon tax was introduced on 1 July 2012 and while its introduction has resulted in an increase in the demand for gas by gas fired generators over the first 12 months of its operation,[81] the growth that was expected to occur has been tempered somewhat by:

- the reduction in the demand for electricity that has occurred across the NEM;[82] and
- the increased use of renewable energy sources, which has resulted in the displacement of some gas fired generation and affected the way in which a number of gas fired peaking plants are operated.

Looking forward, one of the key uncertainties currently affecting this segment of the domestic market is whether a carbon emissions scheme will continue to exist after the federal

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79 Santos has also indicated that the development of shale gas is only likely to proceed if ex-plant gas prices in eastern Australia rise from their current levels of \$3-\$4/GJ to about \$6/GJ. *See* The Australian, Gas price rise prompts Santos to revamp Cooper Basin, 23 May 2011.

80 AER, State of the Energy Market, 2012, p.94.

81 According to estimates reported by EnergyQuest, the demand for gas by gas fired generators in the first nine months of the operation of the carbon tax (1 July 2012-31 March 2013) was 10.5% higher than it was over the same period the year before. See EnergyQuest, EnergyQuarterly, November 2012-May 2013, tables 55 and 56.

82 Estimates reported by EnergyQuest suggest that in 2012 demand within the NEM fell by 3%. See EnergyQuest, EnergyQuarterly, February 2013, p.101.

election and, if so, what path carbon permit prices will take once the tax transitions to an emissions trading scheme (ETS).

In addition to these uncertainties, gas fired generators are having to grapple with the adverse effects of:

- subdued growth in the demand for electricity;
- the continued expansion of renewable energy sources under the LRET;
- higher gas prices; and
- the cessation of the Queensland Gas Scheme[83] at the end of 2013.

Given the conditions prevailing at this time, it is not surprising that AEMO's latest planning scenario projections assume that:

- the demand for gas by gas fired generators in some jurisdictions will *contract* in the short to medium term. AEMO's current projections assume that the demand from this segment will fall by around 20% between 2012 and 2020 and will continue to fall until 2025, after which it is expected to start to increase.[84] The two jurisdictions that are expected to feel these effects most acutely are South Australia and Queensland;[85] and
- no new investment in gas fired generation will be required in the short to medium term. AEMO's current projections assume that additional gas fired peaking capacity will not be required until at least 2025 while new CCGT investment is not expected to be required until after 2032. The effect of these factors on new investment is already starting to be felt, with a number of gas fired generation proponents announcing they have suspended their proposed developments.[86]

Only time will tell whether these projections are actually borne out, or whether some of the projected decline will be alleviated by:

- changes in government policy (eg, through a reduction or cessation of LRET or the introduction of other policies that favour gas fired generation);
- changed conditions in the electricity market; or
- higher carbon permit prices if a carbon emissions scheme remains in place after the election.

It is worth noting, however, that if demand from this segment contracts, it will alleviate some of the demand-supply imbalance expected to arise when the LNG projects come on line.

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83 The Queensland Gas Scheme requires electricity retailers to obtain 15% of their electricity requirements from gas fired generation.

84 AEMO, Gas Statement of Opportunities, 2012, Figure A-13.

85 ibid, Appendix A.

86 For example, AGL announced in October 2012 that it had suspended development of the proposed 1,000 MW Dalton Power Station and EnergyAustralia has reportedly suspended the development of the second Tallawarra Power Station. See AGL, AGL suspends development of Dalton Power Station, 19 October 2012 and EnergyQuest, EnergyQuarterly, May 2013.

4.4 Outlook for the demand-supply balance, prices and flows

Drawing on the material set out above, it is clear that the eastern Australian gas market is currently undergoing a significant transformation, with a number of fundamental changes occurring on both the demand- and supply-sides of the market. The precise effect that all these developments will have on the demand-supply balance, gas prices and the movement of gas in the short to medium term is difficult to determine at this stage. However, there is a general perception in the market that:

- the demand-supply balance will continue to tighten in the short to medium term, with the effects of the tightening being felt most acutely in Queensland;
- gas prices will continue to converge toward the LNG netback level in the short to medium term and are unlikely to fall back to their historic levels even if new sources of supply are brought on line because of the higher production costs associated with new sources; and
- pipeline utilisation and the directional flow of some pipelines could change if less gas from the Cooper and Bowen/Surat basins flows into south eastern Australia (once existing contracts roll off) and more gas from Victoria is supplied into NSW, ACT, South Australia and, potentially Queensland,[87] until new sources of supply are brought on line.

These effects are explored in further detail below.

4.4.1 Future demand-supply balance

The critical question currently facing the eastern Australian gas market is whether domestic oriented production will be able to expand rapidly enough to ensure there is sufficient gas available in the domestic market over the period 2015-2018, which is when:

- a large number of domestic contracts expire (2015-2017); and
- the LNG projects will be ramping up to full capacity (late 2014-2018) and a significant proportion[88] of the gas previously directed into the domestic market by both the LNG proponents and the Cooper Basin will be diverted to the LNG facilities.

While it is possible that production from existing sources in eastern Australia could increase,[89] the gap that will be left as a result of the LNG developments is such that new sources of supply will need to come on line in this period. The difficulty the market currently faces is that only one of the proposed developments has passed the final investment stage (see Table 4.2). It is unclear therefore at this stage whether the remaining developments will

[87] The term 'potentially' is used in this context because there would be significant transportation costs associated with supplying gas from Victoria to Queensland and other hurdles that would have to be overcome, including the limited physical interconnection between some pipelines and having to rely on an 'as available' backhaul transportation services unless the predominant flow of gas changes.

[88] Note that not all of the gas currently supplied by the LNG proponents into the domestic market will be diverted to LNG because some of the gas will still be the subject of long term gas supply agreements.

[89] For example, if the Gippsland Basin JV was able to reduce its commitment to meet peak demand in winter (ie, by entering into contracts with lower load factors), it could increase output over the remainder of the year.

proceed and, if so, the extent to which they will be used to supply the domestic market (see section 4.2).

The other key uncertainty currently facing the market is whether those projects that pass the final investment decision stage will be able to be brought on rapidly enough to fill the gap in the domestic market that is expected to emerge from 2015. Given that a number of the projects are still in the exploration stage and will require the development of new production facilities and/or pipelines, it is unlikely that gas from these new sources will be available to the market by 2015.[90]

Even if all the projects that have certified reserves (ie, Kipper, Gunnedah, Gloucester and Ironbark) are developed in time and dedicated to the domestic market, this would only result in an additional 116.5-136.5 PJ pa of gas being available, which is 50-70 PJ pa[91,92] less than what is currently supplied by the LNG proponents into the domestic market. While some of this difference may be made up through increased production from existing sources, other new sources of supply are likely to be required, or domestic demand will have to fall.

As the preceding discussion highlights, it is unlikely that the new sources of supply most likely to proceed in the next two to three years will be brought on line quickly enough, or will be of a sufficient scale to fill the gap that is expected to be left by the LNG developments. It is not therefore surprising that conditions in the market are expected to become even tighter from 2015,[93] or that some market commentators, such as EnergyQuest, are projecting a supply shortfall to emerge around this time.

EnergyQuest's latest demand and supply projections are reproduced in Figure 4.3. Some of the key points to note from these projections are:[94]

- Domestic demand is forecast to fall by around 100 PJ pa between 2014 and 2017 and remain around 600 PJ pa as a result of higher gas prices, the cessation of the Queensland Gas Scheme and the continued expansion of renewable energy.
- Supply from the Gippsland Basin is expected to remain relatively steady, while supply from the Otway Basin is expected to *decline* from around 2018, supply from the Cooper Basin is expected to *increase* from around 2019 and supply from NSW is expected to *increase* from 2017-18 and reach around 50 PJ pa in 2019.

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90 Note that this observation is consistent with the potential start dates identified by project proponents – see Table 4.2.

91 According to EnergyQuest's recent production estimates, QCLNG, GLNG and APLNG produced 209 PJ in the 12 months to March 2013 and around 19 PJ was put into storage in 2012. This implies that the LNG proponents supplied around 190 PJ of gas into the domestic market.

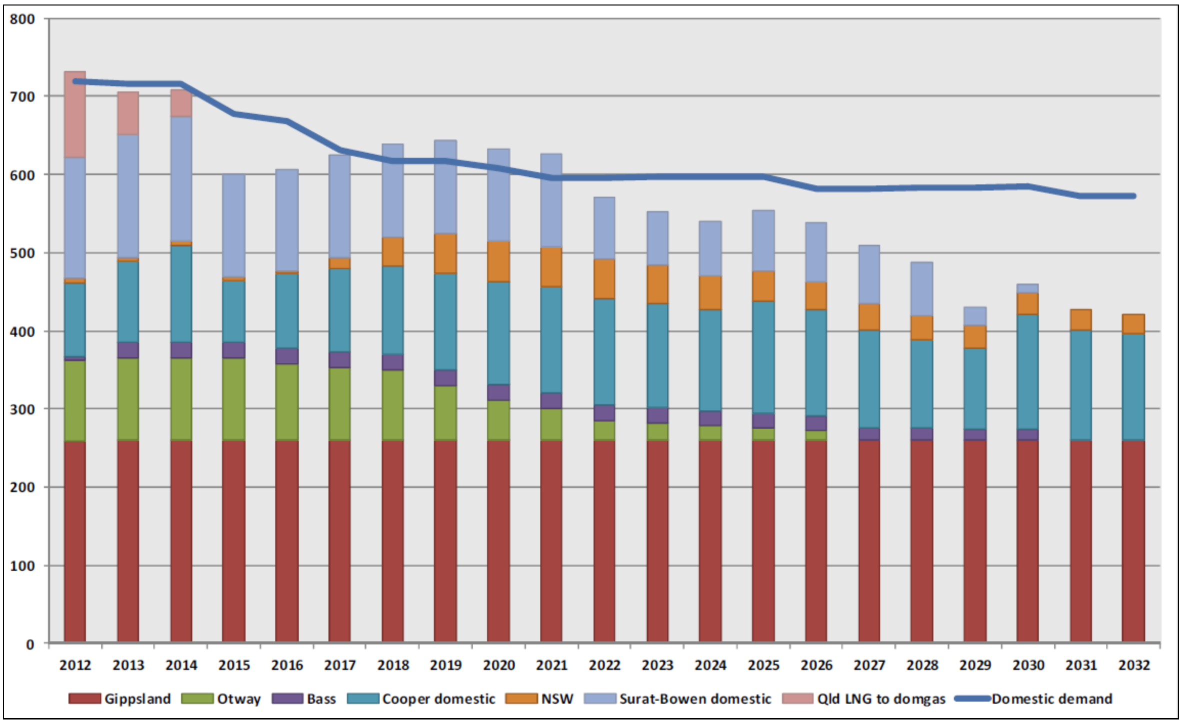
92 While it is possible that the difference may be lower than 50-70 PJ given that some of the LNG proponents have longer term obligations to supply gas into the domestic market (eg, in 2007 AGL entered into a 20 year contract with QGC for the supply of 540-740 PJ of gas), the fact that more gas from the Cooper Basin will be directed to LNG can be expected to counter this somewhat.

93 See for example, BREE, Gas Market Report, July 2012, p.45 and Queensland Department of Energy and Water Supply, 2012 Queensland Gas Market Review, pxi.

94 EnergyQuest, EnergyQuarterly, May 2013, p.25.

- The initial supply shortfall is only expected to last two years (2015 and 2016) although if domestic demand remains at its current level, as assumed in the 2012 GSOO, the shortfall could be larger and persist for a longer period of time than projected by EnergyQuest.

Figure 4.3: EnergyQuest demand and supply projections



Source: EnergyQuest, EnergyQuarterly, May 2013, p.25. See also AFR, Dim future for gas supply, 27 May 2013.

4.4.2 Gas prices

Gas prices in eastern Australia have historically been determined by domestic market conditions. However, as the LNG developments in Queensland have become more of a reality and conditions in the market have tightened, prices have started to converge toward the LNG netback level (export parity pricing), with the prices struck under a number of new contracts reportedly being either linked to an international oil price benchmark, or a level consistent with the LNG netback price. For example:

- In April 2013, Origin announced it had entered into a conditional agreement with Beach Energy to purchase up to 17 PJ pa from Beach Energy's interests in the Cooper Basin over an eight year period (with a two year extension option) commencing in 2015. According to Origin's media release, the price specified in this contract is linked to oil and other parameters.[95]
- In May 2013, Lumo announced it had entered into a new gas supply agreement with the Gippsland Basin JV, which would involve the purchase of 22 PJ of gas over a three year period commencing in 2015. According to Infratil's media release, the price specified in this contract is linked to an oil price benchmark.[96]

[95] Origin, Origin expands east coast portfolio with agreement to purchase gas from Beach Energy, 10 April 2013

[96] Infratil Ltd, Lumo Energy signs gas sales agreement, 14 May 2013.

- In December 2012, Origin announced it had entered into a new seven year gas supply agreement, which would involve the supply of 22 PJ of gas to MMG from 2013. The pricing mechanism adopted in this contract has not been made public, but EnergyQuest has stated it understands the price is *not* linked to an oil benchmark. [97] Media reports suggest the price in this contract will step up to $9/GJ once the LNG plants come on line, which is broadly in line with recent estimates of the LNG netback price at Moomba assuming a US$110/bbl oil price.[98]

Looking forward, the convergence of gas prices in eastern Australia from their historic level of around $3-$4/GJ[99] toward the LNG netback price is expected to continue as more long term gas supply contracts expire and new contracts are entered into. Recent wholesale gas price projections developed by ACIL Tasman for IPART, as part of the 2013-14 to 2015-16 review of regulated retail gas prices in NSW, suggest that wholesale gas prices could reach $10/GJ at Moomba and $8/GJ at Longford[100] in 2013-14 and remain around these levels through to 2015-16. These projections are broadly in line with:

- the average price that respondents to a recent survey of gas users in NSW, Victoria, Queensland and South Australia conducted by the Australian Industry Group claim to have been quoted for longer term contracts ($8.70/GJ);[101] and
- the upper end of the range Santos has stated it expects gas prices to reach ($6-$9/GJ) once the LNG facilities become operational.[102]

The projections are, however, lower than EnergyQuest's latest forecast, which is that gas prices will reach $12/GJ over the period in which the LNG projects are ramping up to full capacity (2015-2018) before settling back to $8-$10/GJ.

The effect of higher wholesale gas prices on retail prices is unlikely to be felt until 2015-2018, which is when most retailers' existing gas supply contracts are due to expire.[103,104] With wholesale gas prices accounting for around 30% of retail prices,[105] the increase will obviously not prompt a one for one increase in retail prices. However, the increase is still expected to have a material effect on retail gas prices, with BREE estimating that a doubling

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97 EnergyQuest, EnergyQuarterly, February 2013, p.22.

98 *The Australian*, Origin Energy secures record gas price, 21 December 2012.

99 AER, State of the Energy Market, 2012, p.94.

100 ACIL Tasman, Cost of gas for the 2013 to 2016 regulatory period, 13 June 2013, pp. 22 and 25. The estimates referred to in this context are based on the medium scenario developed by ACIL Tasman.

101 Reported by the Grattan Institute on page 12 of its report entitled, Getting gas right: Australia's energy challenge, June 2013.

102 *The Australian*, Santos confident gas prices will rise, 22 February 2013.

103 See AGL, Macquarie Australia Conference, 2 May 2013, slide 14 and also commencement dates for new supply agreements entered into by Lumo and Origin.

104 Note it is possible that retailers could try and raise prices prior to this, if they were to set prices on the basis of the opportunity cost of gas, rather than the prices payable under contract.

105 IPART, Final Report: Review of regulated retail prices and charges for gas, June 2013, p.4.

of wholesale gas prices would result in a 33% increase in retail prices.[106] Projections developed by the Grattan Institute also suggest that the effect will be felt most acutely in Victoria, with the annual average household bill increasing by approximately $170 (~20%) by 2020.[107] In the other states, the Grattan Institute has projected that over the same period the annual average household bill will increase by around $90 pa in South Australia, $65 pa in NSW, $60 pa in Queensland and $40 pa in Tasmania.[108]

4.4.3 Pipeline utilisation

In addition to affecting gas prices, the developments underway in the market could affect the utilisation of a number of pipelines and/or cause the directional flow of some pipelines to change. The way in which this could occur can be seen in the following *hypothetical* examples:

- If there is a significant reduction in gas supplied from the Cooper and Bowen/Surat basins into NSW/ACT and South Australia once existing contracts expire, and more gas has to be supplied to these jurisdictions from Victoria until new sources are developed, then the utilisation of both the MAPS and MSP (or part thereof) could fall. If this was to occur, the utilisation of the other pipelines servicing Sydney, Canberra and Adelaide (eg, the EGP, the DTS/Interconnect/MSP (Culcairn to Sydney/Canberra) and the SEA Gas Pipeline) would need to increase.
- If significant volumes of gas from the Cooper Basin flow to Queensland, the predominant flow of gas on the QSN and SWQP could revert to an easterly direction (ie, from Moomba to Wallumbilla).
- If significant volumes of gas flow from Victoria to Queensland, then, depending on which route[109] the gas takes, the predominant flow of gas on the MSP or MAPS could change, along with the flow of the QSN and SWQP.

Given the uncertainties currently prevailing in the market, it is not possible to determine whether any of these hypotheticals is likely to eventuate or, if they do, the likely timing or extent of their effect on pipeline utilisation/directional flow. It is, nevertheless, worth being aware of the potential for the changes underway in the market to affect gas flows and pipeline utilisation.

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106 BREE, Gas Market Report, July 2012, p.55.

107 Grattan Institute, Getting gas right: Australia's energy challenge, June 2013, p.11.

108 ibid.

109 There are three alternative routes that gas supplied from the Gippsland Basin could take, ie, Eastern route: EGP/MSP (backhaul)/QSN and SWQP (backhaul); Central Route: DTS/MSP (backhaul)/ QSN and SWQP (backhaul); and Western Route: DTS/SEA Gas Pipeline/MAPS (backhaul) and QSN and SWQP (backhaul).

4.5 Commonwealth Government's Energy White Paper

In late 2012, the Commonwealth Government published the Energy White Paper. Amongst other things, the Energy White Paper outlined the Commonwealth Government's view on:

- the longer term objectives for gas market development and the reform process in eastern, northern and Western Australia;
- the need for further market development to promote 'more informed and balanced long-term decision-making and to improve trading flexibility'; and
- how policy success should be measured.

The Commonwealth Government's views on these issues are captured in the following extracts taken from the Energy White Paper:

> "The next steps in the reform process should be considered in the context of the longer-term direction of gas markets and, in particular, the characteristics that mature gas markets should display. Those characteristics could include:
>
> - mature and well-functioning physical and financial markets with upstream and downstream trading platforms to promote flexible trading and transfers of gas
>   - this could include a greater reliance on harmonised spot markets supported by robust secondary markets for managing risk and promoting market transparency
>   - arrangements could also provide for competitive access to unused pipeline capacity and easier title transfers
> - highly flexible and connected networks, including interactions between electricity and gas
> - mature sets of commercially public market information that supports efficient trading, including information on prices, volumes and infrastructure capacity.
>
> Options for achieving these goals will rightly be the subject of ongoing discussion between governments and market participants. The Australian Government welcomes open debate about the longer-term direction of the market.
>
> The government considers that current market development priorities should include a greater ability to go to market for price, easier transfers of title, competitive access to unused pipeline capacity, better rewards for efficient pipeline investment, and confidence in the ability to access gas from the market."[110]

> "Policy success in further developing our gas markets and addressing transitional pressures should produce:
>
> - more competitive and efficient gas markets with:
>   - greater trading flexibility, including through the development of an upstream trading facility in the eastern market and the development of a short-term trading market in the west

[110] Commonwealth Government, Energy White Paper 2012, p141.

  - improved transparency, including on price discovery, supply–demand balances and pipeline capacities
  - increased market liquidity, including in secondary markets
  - adequate supply to meet current and projected domestic and export needs
  - efficient interactions with electricity markets
- a more interconnected and extensive gas pipeline network driven by efficient and timely investment signals
- an investment schedule in gas development, processing and transmission pipeline and distribution infrastructure that can meet projected demand in all three geographical markets."[111]

4.6 Reviews currently underway and recently completed

The conditions currently prevailing in the eastern Australian gas market have attracted a lot of media and political attention and there are a number of reviews currently underway, including:

- the Department of Resources, Energy and Tourism (DRET) and Bureau of Resources and Energy Economics (BREE) joint study into the demand and supply conditions currently prevailing in eastern Australian and potential supply impediments, which is expected to be completed by the end of 2013;[112]
- the Standing Council on Energy and Resources' (SCER) review of gas transmission pipeline capacity trading, which is currently in the consultation phase and is due to be completed by the end of 2013;[113]
- the Peter Reith Victorian Gas Task Force, which was formed by the Victorian Government in early 2013 to examine gas supply and pricing issues and is due to report back to the Victorian Government in the latter half of 2013; and
- the NSW Legislative Assembly's inquiry into downstream gas supply and availability in NSW, which commenced in April 2013 and is currently in the consultation phase.[114]

In addition to these reviews, the following studies have recently been published:

- The Grattan Institute has recently published a report entitled, *Getting gas right – Australia's energy challenge*, which examined the issues currently affecting the eastern and Western Australian gas markets and made a number of recommendations on the role that government and industry should play in ensuring markets work efficiently and new sources of supply are developed.

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111 ibid, p145.

112 Minister for Resources, Energy and Tourism, Media Release – Lifting the lid on Australia's gas markets, 27 May 2013.

113 SCER, Regulation Impact Statement Consultation Paper – Gas Transmission Pipeline Capacity Trading, 15 May 2013.

114 Parliament of NSW website (http://www.parliament.nsw.gov.au/prod/parlment/committee.nsf/0/FCDC7EAF8B2C87F6CA257B4300755E93)

- The Energy Supply Association of Australia (ESAA) has recently published a report prepared by Deloitte entitled, *Assessment of the East Coast gas market and opportunities for long-term strategic reform,* which examined a range of issues in the eastern Australian gas market and made a number of recommendations on areas for future reform. Some of the areas for reform cited in this report include:[115]
  - reducing the risks of participating in facilitated markets;
  - addressing high transaction costs in both the facilitated markets and the underlying gas supply and transportation contractual arrangements;
  - investigating the options for developing a more liquid transparent wholesale market for both gas and transportation services;
  - requiring a more detailed, independent and transparent assessment of the costs and benefits associated with new supply hubs and capacity trading; and
  - improving the regulatory settings applied to exploration and production.

  Deloitte also made the following observation about the current reform agenda:[116]

  > We note that there are a number of recent and ongoing government initiatives aimed at enhancing the performance of the East Coast gas market against the NGO, many of which touch on the issues raised above. However, a number of recent reform initiatives appear to be focussed on ad hoc reforms, and in particular, have maintained the approach taken in the establishment of the facilitated markets whereby the reforms are designed around maintaining existing contractual arrangements for commodity and transport. We consider that these arrangements, while preserving the integrity of the long-term contracts between market participants, also limit the depth and liquidity of wholesale gas trading as the fundamental commodity and transport markets transactions occur outside the facilitated markets.
  >
  > The limited size of the East Coast gas market may mean that it is not feasible to make any substantial transition from a contracting model with some trading of imbalances to ensure short-term matching of supply and demand. However, we consider that the present reform agenda, and in particular the broader initiatives under SCER and the AEMC provide a promising opportunity to develop a clear roadmap for reform for addressing issues with existing market arrangements to support increased trading and competitiveness.

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[115] Deloitte, Assessment of the East Coast gas market and opportunities for long-term strategic reform, June 2013, pp. 10-11.

[116] ibid, pp. 11-12.

5. Gas Supply and Transportation Arrangements

Gas in eastern Australia is currently supplied under medium to long term wholesale[117] gas supply agreements, which are entered into on a bilateral basis between producers and retailers and other large end-users of gas. In most cases these agreements provide for the supply of gas on an ex-plant basis. Buyers must therefore also enter into transportation contracts with the owners of any transmission pipelines that are required to transport the gas from the producer's facility to their delivery point.

While medium to long term bilateral arrangements are the predominant form of contracting in this market, retailers and other large end-users may, depending on the nature of their end-use requirements (see section 3.1), also use short term[118] or as available[119] contracts to supplement their seasonal or annual gas requirements. Some buyers may also be in a position to:

- trade any gas or reserved transportation capacity they don't require with another buyer or shipper; and/or
- enter into a swap with another party to facilitate the supply of gas to particular locations (a locational swap), or over time (a timing swap).

The remainder of this chapter explains:

- why medium to longer term contracts have remained the predominant form of contracting in eastern Australia;
- the key features of wholesale gas supply and gas transportation agreements;
- the role that secondary trading and swaps can play in the market and the factors that will influence a market participant's decision to enter into these types of transactions;
- the risk management tools that buyers can use to manage volume risk; and
- the influence that an end-user's requirements will have on the types of contracts and risk management tools it requires.

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117 The term 'wholesale' is used in this context to refer to the supply of gas to those buyers that contract directly with producers and pipeline owners.

118 For example, a retailer may enter into a short term winter gas supply and transportation arrangement to ensure it has access to sufficient gas and transportation capacity during the winter peak.

119 For example, a gas-fired peaking generator may enter into an 'as available' gas supply and transportation contract so it has the option of generating additional electricity during peak periods if the gas/transportation capacity is available.

5.1 Reliance placed on medium to long term contracts

The wholesale supply and transportation of gas in eastern Australia has historically been underpinned by long term contracts (ie, contracts with a term of 10 years or more).[120] The reliance placed on this type of contract has tended to reflect the needs of both:

- producers and pipeline owners to underwrite the significant capital investments associated with bringing new production facilities on line, constructing new pipelines and carrying out major capacity expansions or other capital works over the life of the assets; and
- larger end-users that need to make significant investments in their own facilities (eg, gas fired generators, LNG proponents, mining companies and large industrial customers), to ensure that they have access to gas over a sufficiently long period (ie, long term contracts can be used to ameliorate security of supply risks). While new entrant retailers may not have the same need to enter into long term contracts, incumbent retailers have in the past tended to rely on this type of contracting.[121]

As the eastern Australian gas market has matured and deepened, the following has occurred (see Table 5.1 for examples):

- producers and pipeline owners that have recovered a significant proportion of their initial investment, such as the Gippsland Basin and Cooper Basin joint ventures, have been willing to enter into medium term contracts (ie, contracts for three or more years);
- new production facilities and pipelines have continued to be underwritten by long term foundation contracts;
- major expansions of contract carriage pipelines have continued to be underwritten by long term contracts; and
- large end-users that have needed to underwrite new investments, expand their facilities, or have otherwise wanted to ameliorate security of supply risks, have continued to seek out long term contracts, while other large-end buyers and retailers have opted for medium term contracts.

The predominant form of contracting in eastern Australia at this point is therefore a mix of both medium and long term contracts.

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[120] For example, the development of both the Cooper Basin and the MSP in the 1970s were underwritten by a 30 year contract. The proposed development of PNG was also to be underwritten by 10-20 year foundation contracts with a number of users.

[121] For example, in 2002 AGL entered into a number of long term gas supply agreements with the Gippsland Basin producers, the Cooper Basin producers and Origin to secure the supply of 1,408 PJ of gas over a 15 year period and in 2006, entered into a 540 PJ 20 year gas supply agreement with QGC.

See AGL, AGL Announces New Gas Supply Portfolio, 18 December 2002 and AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006.

Table 5.1: Examples of contracts entered into over the last 10 years

New fields or pipeline developments
Origin's development of some of its CSG fields was underpinned by a **15 year** GSA entered into with AGL in 2002.[1]
Woodside's development of Geographe and Thylacine was underpinned by a **10 year** GSA entered into with TRUenergy (now EnergyAustralia) in 2002.[2]
Origin's development of the Argyle field was underpinned by a **10 year** GSA entered into with Incitec Pivot in 2004.[3]
Santos' development of Casino was underpinned by a **12 year** GSA entered into with TRUenergy (now EnergyAustralia) in 2004.[4]
QGC's development of some of its CSG fields was underpinned by a **20 year** GSA entered into with AGL in 2006.[5]
Nexus' Longtom development was underwritten by a **10 year** gas and liquids supply agreement entered into with Santos in 2007.[6]
New pipelines
The SEA Gas Pipeline was developed through a joint venture partnership, involving Origin, TRUenergy (now EnergyAustralia) and International Power (now GDF Suez), each of which then entered into a **15 year** foundation contract, which includes an option to extend the contract term by a further 10 years.[7]
The construction of the QSN Link was underwritten by a **15 year** foundation contract with AGL.[8]
Expansions of existing pipelines
The expansion of the Interconnect was underwritten by a **15 year** contract with Origin and was carried out to enable gas to be transported to the Uranquinty power station in 2007.[9]
The expansion of the westerly capacity of the SWQP has been underwritten by two long term contracts entered into with AGL (**15 year** contract) in 2007 and Origin (**22 year** contract) in 2009.[10]
The conversion of the SWQP into a bi-directional pipeline has been underwritten by a **15 year** contract entered into with Santos in 2011.[11]
Use of long term contracts by large end-users
Incitec Pivot entered into a **10 year** GSA with Origin in 2004 and in doing so noted that it had 'secured the long term future of its fertiliser manufacturing plants at Gibson Island in Brisbane'.[12]
Rio Tinto entered into a **20 year** GSA with Origin Energy in 2007 to underwrite an expansion of Yarwun alumina refinery.[13]
Xstrata entered into a **10 year** gas supply and transportation agreement with AGL in 2011 to underwrite the development of the Diamantina Power Station in Mt Isa.[14]
GLNG entered into a **15 year** 750 PJ GSA with Santos in 2010 to ensure they had sufficient gas to underwrite the development of the LNG facilities. In 2012 GLNG also entered into a **10 year** 365 PJ GSA with Origin to further bolster its supplies.[15]
Use of medium term contracts by large end-users and retailers
Victoria Electricity (now Lumo) entered into a **3 year** GSA with Santos in 2008 for supply from Longtom.[16]
MMG entered into a **7 year** GSA with Origin in December 2012 to supply its operations in Mt Isa.[17]
Origin entered into an **8 year** GSA with a 2 year extension option with Beach Energy for supply from Cooper Basin in April 2013 for supply from 2014-15 .[18]
Lumo entered into a **3 year** GSA with the Gippsland Basin JV in May 2013 for supply from 2015.[19]

Sources:

1. Origin, Half Yearly Report to Shareholders for the half year ended 31 December 2002, p.10. 2.TRUenergy, TXU and Woodside sign gas deal, 5 August 2002. 3. Incitec Pivot, Gas agreements secure future of fertiliser plants, 6 September 2004. 4. Santos, Annual Report 2004, p.20. 5. AGL, AGL Secures Cornerstone Investment in QGC, 5 December 2006. 6. Santos, Santos finalises Longtom contract, 26 April 2007. 7. APA, Response to SEPS Coverage Application, 29 January 2013, p.13. 8. HDF, Epic Energy signs foundation contract with AGL underpinning construction of the QSN Link, 13 July 2007, p.2. 9. APA, APA Expands Moomba Sydney Pipeline for Uranquinty Power Station, 27 June 2007. 10. HDF, Epic Energy commits to second stage expansion of the South West Queensland Pipeline, 17 December 2007, HDF, Epic Energy secures conditional agreement with Origin to underpin further expansion of the South West Queensland Pipeline and QSN Link, 16 June 2009 and Origin, Origin to secure long term gas pipeline capacity to link its Eastern Australian portfolio, 16 June 2009. 11. Hastings Funds Management, Gas transmission agreement with Santos is now unconditional, 21 September 2011. 12. Incitec Pivot, Gas agreements secure future of fertiliser plants, 6 September 2004. 13. Origin, Origin Signs New Gas Contract with Rio Tinto Aluminium – Underpins Coal Seam Gas Expansion in Queensland, 3 July 2007. 14. APA, APA and AGL to build gas-fired power station in Mt Isa, 6 October 2011. 15. Santos, Santos to supply 750 PJ of portfolio gas to GLNG, 25 October 2010 and Origin, Origin announces major gas sales agreement with GLNG, 2 May 2012. 16. Santos, Third Quarter Activities Report for Period Ending 30 September 2008, 23 October 2008. 17. Origin, Origin announces long term gas supply agreement with MMG, 20 December 2012. 18. Beach Energy, Beach signs major gas sales agreement with Origin Energy for up to ~139 PJ over eight years, with the potential for a two year extension, 10 April 2013. 19. Infratil Ltd, Lumo Energy signs gas sales agreement, 14 May 2013.

If there were no security of supply concerns and there was no need for any significant new investment in the upstream or transportation segments of the supply chain, then one would expect that as the market continued to mature and deepen, it could move toward trading gas and/or pipeline capacity on a short term basis (eg, through contracts of one year or less or a spot market). However, this is not the position the eastern Australian gas market is currently in.

To the contrary, conditions in the market are expected to continue to tighten, with some market commentators predicting a supply shortfall (see section 4.4). A number of new sources of supply are therefore likely to be required. Bringing these new sources of supply on line will require a significant investment in upstream facilities and, in some cases, new transmission pipelines, and will therefore need to be underwritten by long term foundation contracts. Medium to longer term contracts (ie, contracts with a term of three or more years) are therefore likely to remain the predominant form of contracting for some time to come.

5.2 Wholesale gas supply agreements

Wholesale gas supply agreements are bilateral contracts entered into by producers and large buyers (ie, retailers, large industrials, mining companies, gas fired generators and LNG proponents), which set out the volume of gas to be supplied by the producer, the price to be paid by the buyer and the other terms and conditions upon which the gas will be made available.

To accommodate the different end-use requirements of these buyers, the terms and conditions specified within the gas supply agreements have tended to be highly customised. Some of the more significant terms and conditions specified in wholesale gas supply contracts include:

- the firmness of the producer's supply obligation, which may be either 'firm' or 'as available'. An 'as available' service, as its name suggests, will only be supplied if the producer has met all of its firm supply obligations and has additional gas that it can supply. Given the uncertainty surrounding deliverability under this type of contract, buyers tend to only use this service to supplement a firm supply contract;
- the location to which the gas is to be delivered, which in most cases is the entry point of the closest pipeline(s) connecting the production facility to the relevant end market;[122]
- the quantity of gas to be made available to the buyer in each year of the contract term (the annual contract quantities (ACQ)), which may only be varied if the contract includes an ACQ variation provision;[123]

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122 Producers in a small number of cases may choose to supply gas on a delivered basis rather than on an ex-plant basis. The delivery point in these types of contracts would therefore be the buyer's premises.

123 ACQ variation provisions are not included in every contract and where they are included, the scope can differ markedly in terms of the type of variation that a buyer can request (ie, increase the ACQ, increase and/or decrease ACQ, or decrease ACQ), the bounds within which this variation can occur and how often it can occur.

- the load factor,[124] which measures the extent to which a buyer can take more than the average daily contract quantity (ie, the maximum daily quantity (MDQ)) throughout the year, subject to the cap imposed by the ACQ being met;
- the take or pay provisions, which specify the minimum proportion of the ACQ that the buyer must pay for in each year.[125] In some cases, these provisions allow the buyer to 'bank' gas that it has paid for but has not taken delivery of, and to take that gas in future years. The price at which this banked gas can be taken and the period over which it will be made available will depend on the terms of the contract; and
- the price payable by the buyer (which is usually a variable charge expressed on a \$/GJ basis), the manner in which the price will be escalated over the term of the contract and a price review clause for those contracts with terms in excess of 3-5 years.

As with any supply contract, buyers may either enter into a single gas supply agreement or may hold a portfolio of supply agreements. The portfolio may consist of contracts with producers in different basins, or may provide for the provision of different types of services (ie, firm and 'as available' contracts) and/or different contract lengths (ie, short, medium and long term contracts).

Finally, while the prices specified in gas supply contracts have historically been expressed on a \$/GJ basis and escalated in line with inflation, the increasing prevalence of LNG netback pricing has resulted in the prices in some new contracts being linked to an international oil benchmark with provision also made for the benchmark to be updated at discrete intervals over the life of the contract.

5.3 Transportation arrangements

The types of transportation contracts and services available to a buyer (referred to in this context as a shipper)[126] will depend on whether the pipeline operates under a market carriage or a contract carriage model and on a network or point-to-point basis. The DTS is the only network and is also the only pipeline operating under the market carriage model. All other transmission pipelines in eastern Australia operate under the contract carriage model and provide point-to-point services. An overview of the services provided by these two types of pipelines and the contractual arrangements underpinning the provision of these services is provided below.

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124 The term load factor is also referred to as the swing factor and is calculated by dividing the MDQ available under the contract by the average daily contract quantities (DCQ). The load factor typically ranges from 100-125%, with a value of 100% implying the buyer can only take its average daily contract quantity and a value of 125% implying that the buyer can vary its daily consumption by up to 125% on any day subject to the constraint that it only takes its annual contract quantities over the year.

125 The take or pay multiplier typically ranges from 80%-100%, with a value of 80% implying the buyer has to pay for at least 80% of the ACQ, irrespective of whether it has taken the gas while a value of 100% implies the buyer has to pay for all of the ACQ.

126 The shipper will in most cases be a retailer or large end-user of gas but if the producer is supplying gas on a delivered basis it will enter into any gas transportation agreement that may be required to get the gas to the buyer's premises.

5.3.1 Contract carriage model

In a similar manner to wholesale gas supply contracts, the services provided by transmission pipelines operating under the contract carriage model are supplied under bilateral contracts entered into between the pipeline owner and the shipper of gas.

The terms and conditions typically specified in these contracts include:

- the services to be provided to the shipper, which may include:
  - a firm forward transportation service – this service enables a shipper to reserve pipeline capacity and receive a higher priority relative to ‘as available’ services;
  - an ‘as available’ service – this service enables a shipper to transport gas without reserving capacity but accords it a lower priority than firm services; and
  - a backhaul service – this service enables a shipper to take delivery of gas at a location that is upstream of the point they are able to supply gas into the pipeline. This service is generally only offered on an ‘as available’ basis because it can only be provided if the volume of gas to be backhauled is less than, or equal to, the volume of gas to be transported on a forward haul basis between these two points.[127]

  If the pipeline in question is underutilised, the shipper can reduce its overall transportation cost by using an ‘as available’ contract to supplement its firm capacity reservation during peak periods. If, however, the pipeline is operating close to capacity, the shipper’s firm capacity reservation will need to be equal to its expected peak requirement to ensure that it can deliver the required quantities of gas in peak periods;
- the location at which gas is to be supplied into the pipeline and delivered;
- the shipper’s capacity reservation (generally expressed on a MDQ and/or maximum hourly quantity (MHQ) basis) if it has entered into a firm transportation agreement;
- the tariffs payable by the shipper (which for firm services are predominantly fixed and calculated by reference to the shipper’s capacity reservation, eg, $/GJ of reserved MDQ) and how the tariffs will be escalated or otherwise updated over contract term; and

[127] This service does not involve the physical transportation of gas. Rather, it simply requires the pipeline owner to reduce the volume of gas that would otherwise be sent on a forward haul basis from the backhaul receipt point and take delivery of an equivalent volume of gas at the backhaul delivery point.

The following example provides some insight into how a backhaul arrangement can work. If A has access to 14 TJ/day of gas in the Gippsland Basin that it wants to supply to Gladstone and it has a transportation contract on the EGP, then it could enter into a backhaul arrangement with APA for supply to Wallumbilla that would notionally involve the use of the MSP, the QSN and SWQP. In this example, A would supply the 14 TJ of gas in Sydney and APA would reduce the quantity of gas that would otherwise have been transported from Wallumbilla to Sydney via the SWQP, QSN and MSP by an equivalent amount, leaving the 14 TJ/day of gas for A to take delivery of at Wallumbilla. If, in this example, there was only 10 TJ of gas nominated to be transported from Wallumbilla to Sydney on a particular day, then APA would be unable to supply all of the 14 TJ/day. It is for this reason that backhaul services are generally only offered on an ‘as available’ basis.

- the imbalance[128] and overrun[129] provisions, which can provide the shipper with some flexibility to manage the variability in demand for gas up to a specified threshold, after which penalty charges are payable.

If the pipeline the shipper needs to use is subject to full regulation and it uses a reference service, then the tariffs and other terms and conditions will be based on those contained in the access arrangement approved by the regulator (see section 7.2.1).[130] If, on the other hand, the shipper's requirements differ from the reference service, then it may negotiate the provision of an alternative service and associated tariffs and other non-price terms and conditions. For pipelines that are not subject to full regulation, the service requirements, tariffs and non-price terms and conditions will be subject to negotiation.

5.3.2 Market carriage model

Under the market carriage model employed in Victoria, shippers seeking to use the DTS are required to, amongst other things:

- register with AEMO to participate in the Declared Wholesale Gas Market (DWGM) and through the daily bidding process inform AEMO of how much they intend to inject and withdraw from the system (see section 6.1);
- enter into a Transmission Payment Deed[131] with the owner of the DTS; and
- enter into a connection agreement with the owner of the network from which the gas is withdrawn if the gas is to be supplied in Victoria or a bilateral transportation contract with the owner of the MSP, EGP or SEA Gas Pipeline if gas is to be exported.

Unlike contract carriage pipelines, shippers utilising the DTS cannot reserve firm capacity. They may, however, have an Authorised MDQ allocation or an AMDQ credit certificate (herein jointly referred to as 'AMDQ'), which provides them with a hedge against congestion uplift charges up to their Authorised Maximum Interval Quantity (AMIQ). AMDQ also entitles them to the following:

- higher priority in the scheduling process than a customer with no AMDQ if there is a tie in injection bids; and
- higher priority access to the DTS than a customer with no AMDQ if there is a constraint in the DTS that requires the curtailment of some users to maintain system security.

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[128] An imbalance occurs if the quantity of gas supplied into a pipeline by a shipper differs from the quantity of gas it takes delivery of. Charges for an imbalance will be payable if the difference exceeds the limit specified in the contract.

[129] An overrun occurs if the shipper delivers more gas than it is contractually entitled to take and therefore exceeds the MDQ or MHQ specified in the contract. Some pipeline owners allow overruns up to a specified threshold and also charge a lower penalty rate for authorised overruns (ie, if the shipper informs the pipeline owner prior to the overrun occurring and the pipeline owner authorises the overrun).

[130] A shipper seeking to utilise the services provided by a regulated pipeline may also need to use a negotiated service if it is to use expanded capacity and the access arrangement does not apply to the expanded capacity.

[131] Under the terms of this deed the shipper agrees to pay transportation charges directly to the owner of the DTS.

AMDQ can be acquired in a number of ways, including by: entering into an arrangement with existing AMDQ holders; applying for AMDQ credit certificates when the DTS' capacity is expanded; funding an expansion of the DTS; acquiring existing ADMQ credit certificates from the DTS owner when they expire; and bidding for spare Authorised MDQ at auction. To encourage a greater degree of trading of AMDQ, AEMO has also recently submitted a portfolio rights trading rule change proposal to the AEMC.

Another point of distinction between the DTS and other transmission pipelines in eastern Australia is that it is essentially a meshed network, consisting of a large number of injection points and withdrawal points (see Figure 6.1). The services offered by the DTS therefore include both injection and withdrawal services, each of which attracts different charges. Different charges are also applied to domestic (Tariff D) and large business (Tariff V) customers.

It is worth noting in this context that the DTS is subject to full regulation and that the injection and withdrawal services have been identified as a reference service. The charges payable for these services are therefore based on the tariffs approved by the AER and are based on actual volumes injected and withdrawn by the shipper.

5.4 Secondary trading of gas and pipeline capacity

If a retailer or other large buyer of gas (the contract holder) has any spare gas or pipeline capacity, it may decide to on-sell it to another buyer that is in a position to utilise the gas or pipeline capacity. This secondary trade may take the form of either:

- a bare transfer – in this case the contract holder's rights (or part thereof) to gas or pipeline capacity are temporarily transferred to the counterparty but the contract holder remains responsible for the financial and operational obligations (eg, making nominations) specified in the agreement. This type of transaction does not require the approval of the producer or pipeline operator; or
- a novation - in this case all of the contract holder's rights and obligations under the gas supply or transportation agreement are permanently transferred to the counterparty. This type of transaction requires the approval of the producer or pipeline operator.

Due to the bilateral and confidential nature of these agreements, it is not possible to determine how frequently either of these types of transactions is used. Anecdotal evidence, however, suggests that these transactions do occur, although they are not widely used.

One potential reason for this is that the decision to enter into a secondary trade, and in particular a bare transfer, involves a range of complex considerations for both the contract holder and the counterparty. The factors that are likely to influence a contract holder and counterparty's willingness to enter into such a transaction can be summarised as follows:

- The contract holder's willingness will depend on, amongst other things:
  - how much spare gas and/or pipeline capacity it has to offer and the period over which it can make that gas and/or pipeline capacity available;

- the opportunity costs associated with not entering into the transaction, which could be quite significant if the transportation costs and/or gas supply costs it faces are predominantly fixed;[132]
- commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market;[133] and
- the transaction costs associated with entering into such an arrangement, which will include the costs incurred in the negotiation and contracting stages and any ongoing costs incurred by either party in managing the arrangement.[134]

▪ The counterparty's willingness will depend on, amongst other things:

- the nature of its demand and, in particular whether:
    - the counterparty is able to make use of the additional gas or pipeline capacity, which will depend on the nature of its end-use requirements,[135] its location[136] and its own contractual position;
    - the period over which the gas or pipeline capacity is to be supplied corresponds with the period over which the counterparty can use the gas;[137] and
    - the firmness of the supply obligation corresponds with the counterparty's requirement.[138]
- the total cost of entering into the transaction (including any transaction costs) *vis-à-vis* the cost of any substitute service.[139]

Given the range of factors influencing both a contract holder's and a counterparty's decisions, it is not surprising that these contracts are not widely used.

One final relevant point is that the contract holder of pipeline capacity is not the only one that can sell unutilised contracted pipeline capacity. The owner of that pipeline may[140] also sell

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132 While the price paid for gas is usually a variable charge ($/GJ charge), if the buyer hasn't taken the take or pay quantities it must still pay for that gas. The price payable up to the take or pay quantities may therefore be viewed as being relatively fixed. To the extent that the buyer's wholesale gas supply contract allows gas to be banked, then the opportunity cost of not entering into this transaction will be lower.

133 For example, if the buyer and counterparty both compete in the same downstream market, the buyer may be reluctant to enter into such an arrangement, if the costs associated with any deterioration in its competitive position exceed the costs of storing the gas or holding onto unutilised pipeline capacity.

134 For example, if the pipeline capacity is traded and the original holder of that capacity is required to make nominations, on the counterparty's behalf, then there will be ongoing costs associated with this type of agreement.

135 For example, a peaking gas fired generator may be in a better position to use the additional gas than an industrial customer that has a relatively stable production process and has contracted all of its gas and transportation requirements.

136 If, for example, the buyer is trying to sell capacity on the MAPS and the counterparty is located in Brisbane then it is unlikely to be interested in entering into such a transaction.

137 For example, if the counterparty requires additional gas or pipeline capacity throughout the year but the buyer is only able to offer it in off-peak seasons, there may be little value to the counterparty in entering into such an arrangement.

138 If, for example, the gas or pipeline capacity is to be supplied on an 'as available' basis, then a counterparty that requires gas and/or pipeline capacity on a firm basis is unlikely to be interested in entering into the transaction.

139 For example, if the price to be charged for a trade of 'as available' pipeline capacity exceeded the price that a pipeline owner was prepared to offer for the same service, the counterparty may be reluctant to enter into such a transaction.

any unutilised contracted capacity to other shippers on an ‘as available’ basis. To the extent that this capacity has already been paid for by the contracting shipper (ie, because transportation charges are largely fixed and are payable irrespective of the volumes transported), then the pipeline owner should have an incentive to enter into such transactions because it will derive additional revenue from the sale. It may also be better placed to offer the service required by the counterparty because it can aggregate spare capacity across multiple users and may also be able to overcome any specific delivery issues.

Whether or not a counterparty will view an ‘as available’ transportation service as a substitute for a bare transfer, however, will depend on:

- whether the counterparty requires a firm service and if the shipper is prepared to offer it such a service; and
- the price and other terms and conditions upon which the contract holder is prepared to offer the capacity through a secondary trade *vis-à-vis* those offered by the pipeline owner.

5.5 Swaps

Swaps are another mechanism that can be used by a small number of buyers and producers to facilitate the supply of gas to particular locations (a locational swap), or over time (a timing swap),[141] and may be used to overcome upstream supply constraints, pipeline constraints and/or to reduce transportation costs. The ability to enter into this type of transaction will depend on whether a counterparty can be found that has an existing obligation to supply gas to a location that can also be supplied by the buyer or producer. It is for this reason that the number of buyers and producers that can enter into swaps is limited.

Whether or not those parties that are in a position to enter into a swap will do so, will depend on a range of considerations, including:

- whether the swap can be structured so the counterparty is no worse off as a result of the transaction; and
- the total cost of entering into the swap *vis-à-vis* the cost of any substitute service. The cost of entering into the swap will include negotiation and contracting costs, any additional transportation costs that must be incurred to enable the gas to be delivered to the relevant delivery location and the swap fee levied by the counterparty.

A simplified example of how a swap can be used is set out in Box 5.1.

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[140] The term ‘may’ is used in this context because the terms of the gas transportation agreement may prevent the pipeline owner from on-selling capacity. It is understood from the stakeholder consultation that this is extremely rare, but it is worth noting nonetheless.

[141] A timing swap involves the swap of gas at different times. For example, a producer that intends to take its facility offline for maintenance may enter into a swap with another producer to meet its supply obligations during this period in return for it supplying the same volume of gas at a later date.

Box 5.1: Swap example

The way in which a swap can work is illustrated in the following simple example, which assumes that:

- A has 5 PJ pa of gas in the Gippsland Basin, which it wants to supply to Gladstone; and
- B has a 5 PJ pa gas supply agreement with producers in the Bowen/Surat basins, which it takes supply of at Wallumbilla and then transports to Victoria under firm long term gas transportation agreements.

In this case, B could supply A with 5 PJ of gas at Wallumbilla while A could supply B with 5 PJ of gas at the Longford injection point in the DTS. A would then be responsible for transporting the gas from Wallumbilla to Gladstone while B would be responsible for transporting the gas through the DTS.

As an alternative to this swap arrangement, A could enter into a transportation contract with the owners of the EGP/MSP/QSN and SWQP, the DTS/SEA Gas Pipeline/MAPS/QSN and SWQP or the DTS/MSP/QSN and SWQP. The choice between these alternatives will depend on the costs of entering into the swap *vis-à-vis* the cost of entering into these transportation arrangements and the firmness of any backhaul arrangements that may be required.

If rather than supplying gas to Victoria, B needed to have its gas delivered to Sydney, then A would also need to enter into a gas transportation agreement with the owner of the EGP or otherwise compensate B for the additional transportation costs. This additional cost would need to be incurred by A because B has an existing long term obligation to pay a relatively fixed charge for transport between Wallumbilla and Sydney and should be made no worse off as a result of the transaction.

While swaps have not been a common feature of the eastern Australian gas market to date, it is possible this could change in the future, given the developments currently occurring in the market (see Chapter 4) and the diversity of interests and obligations a number of producers and buyers (eg, Santos, BHP, AGL, Origin, and EnergyAustralia), now have in a variety of locations in eastern Australia.

5.6 Tools to manage volume risks

One of the more significant risks retailers, large industrial customers, gas fired generators and other large buyers can face when purchasing gas and transportation capacity under medium to long term contracts is that their actual demand for gas will deviate from their contracted quantities over the life of the contract. The specific volume risks buyers may face include:

- the risk that the demand for gas on a particular *day* will exceed the average daily contracted quantities in their gas supply agreement, or the MDQ in their gas transportation agreement;
- the risk that their actual demand for gas over the *year* will be lower than the ACQ in their gas supply agreement, or the MDQ in the gas transportation agreement; and
- the risk that their actual demand for gas over the remaining life of the *contract* falls permanently below the take or pay quantities specified in the gas supply agreement or the MDQ specified in the transportation agreement.

The extent to which a buyer is exposed to these risks will depend on the nature of their end-use requirements and, in some cases, will also depend on the location of the end-user. For example:

- Retailers and gas fired generators will be exposed to a greater degree of daily and annual demand risk than LNG proponents and large industrial customers that have a relatively smooth consumption profile throughout the year and steady demand for their end-product.
- Retailers and gas fired generators servicing locations that exhibit a distinct seasonal trend (eg, Victoria and Canberra), will be exposed to a greater degree of daily demand risk than those servicing locations that are more temperate (eg, Brisbane).

The contractual provisions and other measures that buyers who are exposed to these volume related risks may use to try to ameliorate their effect are set out in the table below. Depending on the scale of the issue, buyers may use more than one of these measures.

Table 5.2: Measures to manage volume risks

	Gas supply	Transportation
Daily demand risks – risk that demand will exceed average daily quantity in GSA or MDQ in GTA		
Contract provisions	Enter into a gas supply agreement with a higher load factor	For small variations in transportation requirements utilise imbalance and overrun thresholds provided in gas transportation agreements
Short term contracts	Enter into a seasonal or short term gas supply with a producer	Enter into a seasonal or short term gas supply with a pipeline owner
Secondary trading options	Purchase additional gas from another buyer	Purchase additional transportation capacity from another shipper
Storage options	Utilise dedicated storage facilities	n/a
	Utilise pipeline storage or storage and loan services	
Facilitated market options	Purchase gas from the Vic DWGM or the STTM in Adelaide, Brisbane or Sydney	
Annual demand risks – risk that demand will be lower than ACQ in GSA or implied ACQ in GTA		
Contractual provisions	Enter into a gas supply contract with a lower take or pay multiplier and, if possible, banking provisions	n/a
Secondary trading options	Sell spare gas to another buyer under a short term contract	Sell spare capacity to another shipper under a short term contract
Storage options	Take delivery of the gas and store it in a dedicated storage facility	n/a
Facilitated market options	Sell gas into the Victorian DWGM or the STTM in Adelaide, Brisbane or Sydney	
Permanent demand risks – risk that demand will be permanently below take or pay in GSA or MDQ in GTA		
Contractual provisions	If possible enter into a gas supply contract that allows the ACQ to be reduced.	n/a
Secondary trading options	Sell spare gas to another buyer under a long term contract.	Sell spare capacity to another shipper under a long term contract.
Facilitated market options	Sell gas into the Victorian DWGM or the STTM in Adelaide, Brisbane or Sydney	

As the information in this table highlights, there are a number of provisions within wholesale gas supply agreements that can be used by buyers that are exposed to these types of risks to try to deal with their effects. From a producer's perspective, providing this level of flexibility can be costly[142] and expose it to the buyer's volume risk. Contracts that accord a buyer a

[142] For example, building production capacity to meet peak demand, which is only used on a small number of days in the year can be costly.

greater degree of flexibility to manage volume risk tend therefore to be priced at a premium to contracts that provide no such flexibility. Buyers will therefore only seek out the flexibility offered by load factor, take or pay, banking and ACQ provisions if they require it.

It is worth noting in this context that there have been some anecdotal reports that some producers may no longer want to offer the same level of flexibility they have offered in the past under new gas supply agreements.[143] If this is the case, then in the future greater reliance will need to be placed on other mechanisms to manage these risks.

5.7 Influence of the nature of demand on contracting

In section 3.1 it was noted that the nature of an end-user's requirements can have a significant influence on:

- the type of gas supply and transportation contracts it enters into;
- whether or not it needs to use risk management tools; and
- whether it is likely to be in a position to enter into a secondary trade.

Some insight into the differences that can exist across different types of end-users can be found in the examples presented in Table 5.3, which should be viewed as illustrative only.

[143] See for example, AGL, Macquarie Australia Conference, 2 May 2013.

Table 5.3: Example of how differences in demand can affect GSAs, GTAs, the use of risk management tools and secondary trading

Characteristic	Retailer		Large industrial customer		Gas fired generator	
	Victoria	**Queensland (diverse customer base)**	**Steady load**	**Lumpy load and ability to switch**	**Base-load to intermediate**	**Peaking**
Consumption profile	Volatile during winter	Relatively flat	Relatively flat	Lumpy	Relatively flat	Volatile
Investment required to use gas or contractual commitment to supply gas	3 year contract with customers	3 year contract with customers	Significant new long term investment	Investment largely recovered	Significant new long term investment	
Ability to switch to other fuels	No	No	No	Yes	No	No
Contract type – gas supply agreement (GSA) and gas transportation agreement (GTA)						
Firm vs 'as available' supply obligation	Firm for all demand requirements.	Firm for all demand requirements.	Firm for all demand requirements.	Firm up to a certain level supplemented with 'as available' to provide some flexibility to switch to alternative fuel	Firm for all demand requirements.	Firm up to a certain level and potentially supplemented with 'as available'
Contract term	At least 3 years and may be supplemented with seasonal contract.	At least 3 years	Long term	Short to medium term	Long term	Long term and may be supplemented with seasonal contract.
Secondary trading of gas and/or pipeline capacity						
Potential to use additional gas/pipeline capacity	Yes during peak periods but will depend if gas and/or pipeline capacity is available during the peak period	Unlikely because all gas requirements contracted	No because all gas requirements contracted	Yes because not all gas requirements contracted	No because all gas requirements contracted	Yes because not all gas requirements contracted and always has an option to produce more electricity
Risk management tools						
Need to utilise	High	Low to medium	Low	Medium	Medium	High
Risk management tools	Access to storage, high load factor, low take or pay multiplier and use of DWGM to trade imbalances	Moderate load factor, low take or pay multiplier and imbalance/ overrun provisions may be sufficient	Low load factor, moderate to high take or pay multiplier and imbalance/ overrun provisions likely to be sufficient to manage risks	Moderate load factor, low take or pay multiplier, ACQ variation provisions and imbalance/ overrun provisions	Moderate load factor, moderate to high take or pay multiplier and imbalance/ overrun provisions may be sufficient	Dedicated storage, high load factor, low take or pay multiplier and use of DWGM or STTM to trade imbalances
Need for imbalance trading mechanism	High	Low although this could change if the retailer's customer base was not well diversified	Low	Low	Low	High

6. Facilitated Markets in Eastern Australia

Large buyers of gas that want to supply their gas into Victoria, or via the DTS, are required to participate in the Declared Wholesale Gas Market (DWGM), while buyers that want to supply gas into, or via, Adelaide, Brisbane or Sydney must participate in the Short Term Trading Market (STTM). The primary purpose of these markets is to enable participants to trade any gas supply imbalances that arise on a day because their actual demand for gas differs from their contracted supply. These markets may therefore be viewed as more of a market-based balancing mechanism that overlays the bilateral contracting arrangements outlined in the preceding chapter, than a commodity market.

Another facilitated market that is currently being developed by AEMO is the Wallumbilla gas supply hub. Unlike the DWGM and STTM, it is intended that this market will operate as more of a commodity market and that participants will voluntarily trade gas within the hub.

The remainder of this chapter provides further detail on each of these facilitated markets.

6.1 Declared Wholesale Gas Market

The DWGM is a single integrated market that:

- enables the market and system operator (AEMO) to manage gas supply, demand and linepack on a pipeline system using market information provided by market participants;
- allows market participants to trade imbalances; and
- sets a daily gas price.

The market was established by the Victorian Government in March 1999 and as part of this process, the following occurred:

- The ownership and operational functions of the DTS were separated and a decision was made to operate the DTS on a market carriage basis.
- The DWGM was developed to enable participants to trade imbalances.
- An independent system operator (VENCorp later AEMO) was accorded responsibility for operating both the DWGM and the DTS balancing gas supply and demand and transportation capacity through a centrally co-ordinated scheduling process.

The rationale for operating the Victorian market in this manner is outlined in Box 2.3. In short, the decision was made because:

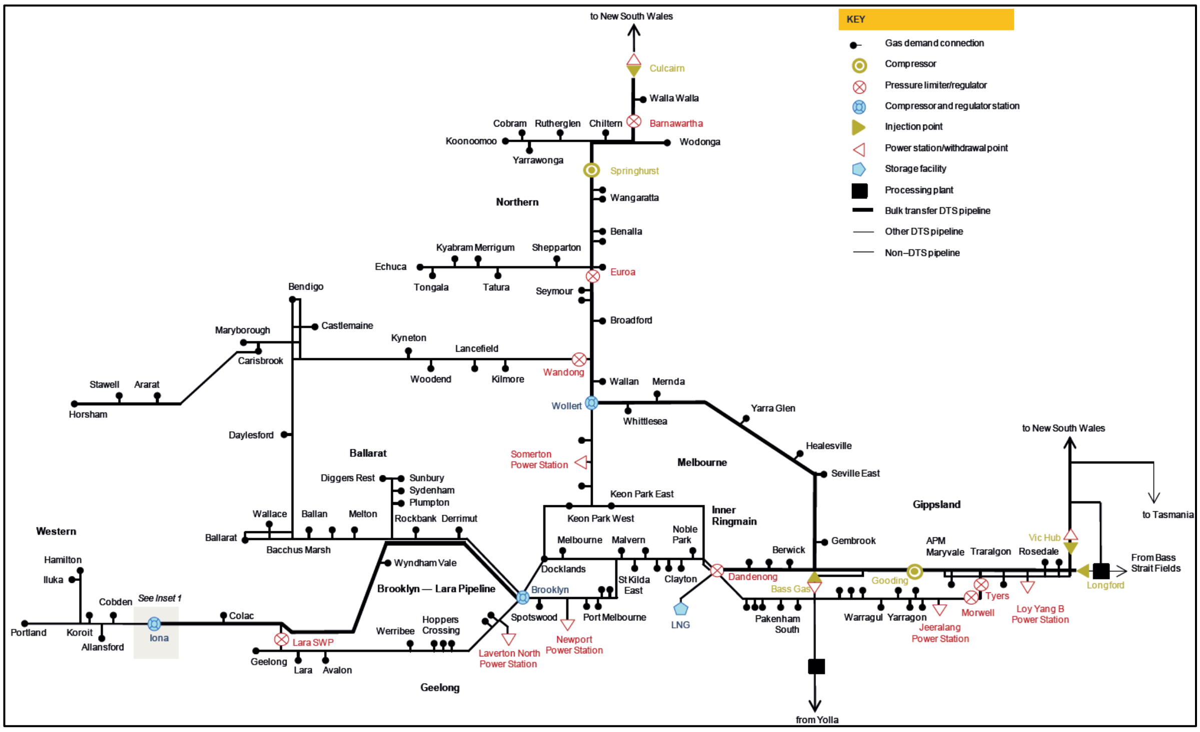
- The DTS is essentially a meshed network (currently consisting of seven injection points and over 120 withdrawal pipelines and a number of pipeline sections that can operate in a bi-directional manner - see Figure 6.1) and the amount of gas that can be stored on the pipeline (linepack) is relatively small, which means it cannot be relied upon to manage significant deviations between forecast supply and actual demand. These characteristics of the DTS mean that it must be closely managed to ensure gas flows in the manner required and the integrity of the system is maintained.

- Residential heating load accounts for a significant proportion of demand in Victoria. Demand tends therefore to exhibit a significant degree of seasonal and daily variation (see Figure 3.3), which means it can be quite difficult for participants to forecast demand and can give rise to significant imbalances.

Operating the market in this manner was also expected to:[144]

- support full retail contestability, which was considered to be of particular importance given the scale of residential consumption in Victoria (see Figure 3.2);[145] and
- encourage diversity of supply and upstream competition.[146]

Figure 6.1: Victorian DTS



Source: AEMO, Victorian Gas Transmission Network – Topological Representation.

The market through which imbalances are traded in Victoria is referred to as the DWGM. Participation in this market is compulsory. Retailers, large customers and traders that want to either supply gas into Victoria, or export gas via the DTS, must therefore register with AEMO as market participants. Registration information published by AEMO indicates that

[144] VENCorp, Application for Authorisation of Market and System Operations Rules, 17 May 2002.

[145] Both the market carriage model and DWGM were expected to encourage new entry because new entrants would not need to enter into long term gas transportation agreements and would also have a mechanism to trade imbalances and/or purchase gas on the spot market.

[146] The transparency of pricing provided by the DWGM was also expected to encourage the development of new sources of supply and upstream competition.

there are currently 25 market participants,[147] 10 of which are retailers, six are traders, two are large end-users, one is a gas fired generator and the remaining six are classified as 'other'.

The price at which imbalances are traded in the DWGM is referred to as the market price. Between 1999 and 2007, the market price was determined on a daily *ex-post* basis, but on 1 February 2007 the market moved to *ex-ante* intra-day trading. The market now has five pricing periods, with the prices prevailing in each period based on the *ex-ante* price. The decision to make these design changes occurred following a review by VENCorp in 2003-04, which found that the existing design did not provide participants with either the ability or the incentive (ie, a price signal) to respond to changing market conditions during the day.[148]

Further detail on how the DWGM operates is provided in Box 6.1 while section 7.4 provides further information on the underlying regulatory and institutional arrangements.

Box 6.1: Key elements of the DWGM

Gas day and pricing periods

The gas day in the DWGM commences at 6 am and consists of the following five pricing periods: 6 am to 10 am; 10 am to 2 pm; 2 pm to 6 pm; 6 pm to 10 pm; and 10 pm to 6 am.

Bids

Market participants are required to provide AEMO with their injection and controllable withdrawal bids at least one hour before the commencement of the gas day. These bids must be submitted via the Market Information Bulletin Board and specify both:

- the quantity of gas market participants expect to inject and withdraw over the day; and
- the bid price for both injections and withdrawals, which can range from $0/GJ (price floor) to $800/GJ (the market price cap).

Market participants may revise their bids during the gas day (subject to some caveats) by resubmitting bids at least one hour before the commencement of the pricing period.

In addition to this information, market participants are required to provide AEMO with the following information: hourly demand forecasts for large customer sites and uncontrollable withdrawals; injection hedge and agency injection hedge nominations; and AMDQ nominations.

Market scheduling and pricing

As independent system operator, AEMO balances gas supply and demand and transportation capacity through a centrally co-ordinated scheduling process, which results in the production of both:

- an operating schedule – this schedule sets out the injections and withdrawals that are to occur in each hour of the gas day and are drawn up by AEMO at the beginning of the gas day and revised throughout each pricing period. These schedules are based on market participants' demand forecasts, bids and hedge nominations, weather conditions, information on other supply constraints and AEMO's system constraints modelling; and
- a pricing schedule – this schedule determines the *ex-ante* market price for the pricing period, and is determined using a bid stack that schedules lower priced gas ahead of higher priced gas. The pricing schedule ignores any constraints within the DTS and may therefore differ from the operating schedule.

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147 AEMO, Spreadsheet entitled INT125_V7_Details_Of_Organisations_1. Note this excludes participants classified as 'End Status'.

148 VENCorp, Victorian Gas Market Pricing and Balancing Review – Recommendations to Government, 30 June 2004. Within this report, VENCorp recommended a number of changes to the design of the DWGM occur in the following stages: Stage 1 – introduction of *ex-ante* intra-day pricing; Stage 2 - introduction of transmission rights; and Stage 3 - development of a number of hubs within the DWGM and introduction of biddable capacity rights. To date, the only changes that have been made to the DWGM are those that were recommended to occur in stage 1.

Imbalances and deviations

Imbalances represent the difference between scheduled injections and scheduled withdrawals. The price paid (received) for imbalances is based on the *ex-ante* market price prevailing in that pricing period.

Deviations represent the difference between actual and scheduled withdrawals/injections. The price paid (received) for deviations is based on the *ex-ante* market price prevailing in the *subsequent* pricing period.

Settlement

The DWGM is settled on a net basis, which means that market participants only pay (receive payment) for the excess of actual withdrawals (injections) over actual injections (withdrawals). The settlement process also takes into account ancillary payments, uplift charges and linepack payments.

Ancillary payments and uplift charges

To ameliorate short term localised constraints AEMO may schedule additional injections of gas at a higher price (including gas from the LNG facility at Dandenong) than the prevailing market price. The difference between the market price and the actual price is referred to as an 'ancillary payment' and is paid to the market participant supplying the additional gas. These ancillary payments are recovered through uplift charges that are, to the extent possible, recovered on a 'causer pays' basis. The categories of uplift charges include:

- Surprise uplift, which is payable by those market participants that deviate from their scheduled injections or controllable/uncontrollable withdrawals or change their demand forecasts in the following schedule;
- Congestion uplift, which is payable by those market participants that cause congestion because their scheduled withdrawals exceed their AMDQ uplift hedge (note the AMDQ uplift hedge is converted to an interval quantity for each scheduling period and is referred to as Authorised Maximum Interval Quantity);
- Common uplift, which is uplift that cannot be allocated to particular market participants and is therefore apportioned to participants that withdraw gas on the day; and
- DTSSP congestion, which is allocated to the owner of the DTS if it is established that it contributed to the congestion by not making the plant and pipeline capacity available.

Market parameters

The market price cap in the DWGM is currently $800/GJ. The last time this was reached was in 2008.

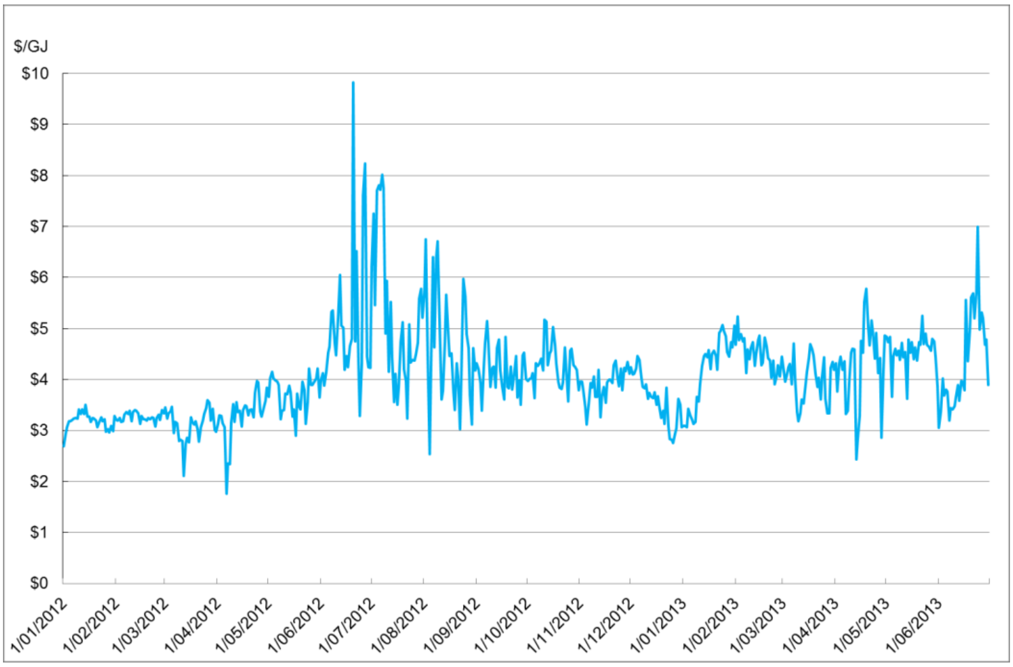
An administered price period may occur if a force majeure event is declared, the market has been suspended, a market price or pricing schedule is unable to be published by the required time or the cumulative price threshold has been reached. During this period the market price is capped at $40/GJ.

The cumulative price threshold is $3,700 and is calculated as the marginal clearing price over the previous 34 scheduling intervals and the current scheduling interval.

Source: AEMO, Technical Guide to the Victorian Declared Wholesale Gas Market, May 2012.

The path that the daily weighted average market price in Victoria has taken over the period 1 January 2012 and 30 June 2013 is illustrated in Figure 6.2. As this figure highlights, the market price in Victoria is quite volatile and exhibits a distinct seasonal trend, with the price peaking in winter and falling over the summer months. This trend is not altogether surprising, given that residential heating load accounts for such a significant proportion of demand in the state (see section 3.1).

Figure 6.2: Daily weighted average market price in the DWGM (1 Jan 2012 – 30 Jun 2013)



Source: AEMO, Price and Withdrawals data. Note that unlike the STTM prices, which incorporate the effect of transportation costs, the DWGM price reflects the cost of the gas only. Participants must therefore pay for transportation on top of the DWGM price.

In terms of the overall size of the market, estimates reported by Deloitte in its recent report for the ESAA suggest that over the period 1 July 2011 – 30 June 2012, 20% of the gas consumed in Victoria was traded at the market price and 7-8% was traded between different parties.[149] The ASX has developed a number of derivative products[150] that are linked to the price payable at the beginning of the day in the Victorian DWGM. It is understood, however, that these products are not heavily traded.

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149 Deloitte, Assessment of the East Coast gas market and opportunities for long-term strategic reform, May 2013, p.44.

150 These products include the Victorian Wholesale Gas Futures, the Victorian Wholesale Gas Strip Futures and put and call options for the Victorian Wholesale Gas Futures Contracts.

6.2 Short Term Trading Market

In late 2005 the Ministerial Council on Energy (MCE) established the Gas Market Leaders Group (GMLG) and tasked it with preparing a Gas Market Development Plan for the eastern Australian gas market by June 2006. [151] One of the key recommendations emerging from the GMLG's Gas Market Development Plan was that further work should be carried out to develop a detailed design for an STTM that would operate in all major demand centres in eastern Australia, except Victoria.

In making this recommendation, the GMLG noted that the STTM would not replace bilaterally negotiated gas supply and transportation contracts as the primary mechanism for the wholesale supply and transportation of gas, or underwriting investment.[152] It was, however, expected to provide a transparent and efficient market based pricing mechanism that could be used by participants to:[153]

- trade imbalances;
- purchase gas on a short term basis without contracting for delivery; and
- efficiently allocate gas during system constraints and emergencies and, potentially, forestall the need for government intervention and market suspension.

The STTM was also expected to provide the market with clear signals of the nature and cost of supply or transmission constraints and encourage efficient contracting and investment in infrastructure.[154]

Following the release of the Gas Market Development Plan, the MCE directed the GMLG to develop the detailed design of the STTM.[155] The GMLG's final STTM design was approved by the MCE in July 2009.[156] In keeping with the GMLG's recommendation, the MCE decided that the STTM would initially be established in Sydney and Adelaide,[157] with the intention that it would later be expanded to other jurisdictions.[158] These two markets commenced on 1 September 2010 and 15 months later a new STTM was established in Brisbane.

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151 The decision to establish the GMLG followed a report prepared by the Allen Consulting Group for the MCE in June 2005, entitled, *Options for the development of the Australian Wholesale Gas Market,* which found that further reform in the market was required to improve transparency, enhance competition and lower potential barriers to entry. The options for reform considered in this report included the development of a Bulletin Board, a city gate scheme (ie, a spot market at demand centres) and the publication of an annual report on the performance of the market and emerging transmission and supply constraints. In the terms of reference issued by the MCE, the GMLG was directed to further develop the Bulletin Board and city gate scheme options, or otherwise develop an alternative market development plan that provided for equivalent benefits in terms of transparency and reducing barriers to entry.

See MCE, GMLG – Gas Industry and Users Working Group to Develop a Gas Market Development Plan – Terms of Reference, November 2005 and ACG, Options for the Development of the Australian Wholesale Gas Market – Final Report, June 2005.

152 GMLG, National Gas Market Development Plan, June 2006, p.6.

153 ibid, pp. 5-7.

154 ibid, p.42.

155 MCE, Communiqué, 27 October 2006.

156 MCE, Communiqué, 10 July 2009.

157 The STTM replaced the compulsory balancing arrangements that had previously been in place in Sydney and Adelaide.

158 MCE, Communiqué, 10 July 2009.

Like the DWGM, participation in the STTM is compulsory. Shippers that deliver gas to, or via, the STTM hub and users that withdraw gas from the STTM distribution system are therefore required to be registered with AEMO. At present there are:[159]

- nine shippers and seven users (six retailers and one large end-user) in the Adelaide STTM. All of the registered users in this STTM also have a corresponding shipper status;
- eight shippers and eight users (four retailers, three large end-users and one generator) in the Brisbane STTM. Of the eight registered users, all but one has a corresponding shipper status; and
- 12 shippers and ten users (five retailers, four large end-users and one generator) in the Sydney STTM. Of the ten registered users, all but one has a corresponding shipper status.

The STTM differs in a number of fundamental respects from the DWGM. For example:

- In the STTM AEMO is responsible for operating the market but has no operational control over the transmission pipelines or distribution pipelines that are connected to the hub because these pipelines are operated on a contract carriage basis.
- The STTM operates on a day ahead basis while the DWGM operates on an intra-day basis.
- The STTM has a market operator service (MOS), which is used by AEMO during the gas day to balance what was scheduled to be transported on the pipelines servicing the hub and the actual quantities transported by the pipelines. Shippers and pipeline operators that have the capacity to increase or decrease the quantities of gas supplied on the pipeline (eg, by using overrun provisions or pipeline storage services) over the MOS period are able to bid to supply this service.
- The STTM has a contingency gas mechanism, which can be called upon by AEMO when the normal operation of the STTM is unable to balance demand and supply, eg, during emergencies. In short, this mechanism allows shippers that are able to increase supply or curtail their demand to bid to provide contingency gas and be compensated if scheduled.
- The STTM includes a capacity payment mechanism, which is used when a pipeline is constrained and shippers with firm capacity reservations are displaced by shippers with an ‘as available’ transportation service. This mechanism is not required in the DWGM because there are no firm capacity transportation rights in the DTS.
- The value of a number of the market parameters, such as the market price cap ($400/GJ) and cumulative price threshold ($440/GJ) are lower in the STTM than in the DWGM.

Further detail on how the STTM operates is provided in Box 6.1 while section 7.5 provides further information on the underlying regulatory and institutional arrangements.

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159 AEMO, Spreadsheet entitled int670_V1_registered_participants_rpt_1. Note the numbers below exclude subsidiaries that are separately registered.

Box 6.2: Key elements of the STTM

Gas day

The gas day in the Sydney and Adelaide STTMs commences at 6.30 am and in Brisbane commences at 8 am.

Bids

On the day before the gas day (D-1), shippers can submit offers to supply gas to the hub and users can submit bids to purchase gas from the hub up to the close of trade (12 pm in Sydney and Adelaide and 1.30 pm in Brisbane). Bids and offers will only be accepted if the participant has the trading rights to flow the gas offered or bid for. The bids and offers can fall within the range of \$0/GJ (price floor) to \$400/GJ (the market price cap).

At defined intervals, shippers and pipeline operators that have the capacity to increase or decrease the quantities of gas supplied on the pipeline can offer to provide MOS. The MOS cost cap is currently \$50/GJ.

Market scheduling, pricing and MOS

At the close of trade on D-1 the following occurs:

1. AEMO determines the *ex-ante* market price for gas day (D) using a bid stack that schedules lower priced gas ahead of higher priced gas.
2. Once the bid stack is established AEMO producers an *ex-ante* market schedule, which sets out the gas to be supplied to the hub by each shipper and the gas to be taken from the hub by each user on the gas day.
3. The shipper nominates the quantity of gas it requires to be transported to the hub on gas day (D) from the relevant pipeline operator.
4. The pipeline operator prepares a pipeline schedule, which sets out the quantities of gas that are scheduled to flow over the next day for each shipper.
5. Once the schedules are issued, shippers can place offers for the provision of contingency gas if required.

Gas that is supplied and withdrawn according to the *ex-ante* schedule is settled at the *ex-ante* price. Where gas supplies and withdrawals deviate from the *ex-ante* schedule, then deviation and/or market scheduled variation penalty charges will be payable (see below).

On a periodic basis, AEMO develops the MOS cost stack, which sets out how pipeline deviations on a gas day will be allocated to MOS providers. If MOS is called upon, the providers are paid their MOS offer price and are also exempt from deviation charges. MOS providers are also paid for the gas supplied, with the price based on the *ex-ante* market price prevailing on D+2. The only way participants can hedge against MOS charges is to be a MOS provider. However, if the participant is just a user and doesn't have transportation rights it can't hedge.

Deviations and market schedule variations

Where shippers and users deviate from the *ex-ante* schedule, 'deviation' charges will be levied having regard to a graduated penalty table, which takes into account the adjusted *ex-ante* market price, the *ex-post* imbalance price and, where relevant, the contingency gas price. The *ex-post* imbalance price is calculated on D+1 and is the price that would have prevailed if the market schedule was based on actual rather than forecast quantities.

Provision has also been made in the STTM for transactions to occur off-market (ie, if a user requires more gas on a day than anticipated, it can enter into a bilateral arrangement with a shipper) and for parties to submit 'market schedule variations' (MSV) to AEMO. Variations of this form still attract a penalty (which is calculated by reference to a graduated penalty table), but the penalty is lower than deviation charge.

Capacity charges

When a pipeline is constrained, a shipper offering lower priced gas that has an 'as available' transportation contract may displace gas that would otherwise be transported by a shipper with a firm capacity reservation that offers to supply gas at a higher price. To compensate the shipper with firm capacity, provision has been made for the 'as available' shipper to pay the firm shipper a 'capacity payment' for use of its contracted capacity.

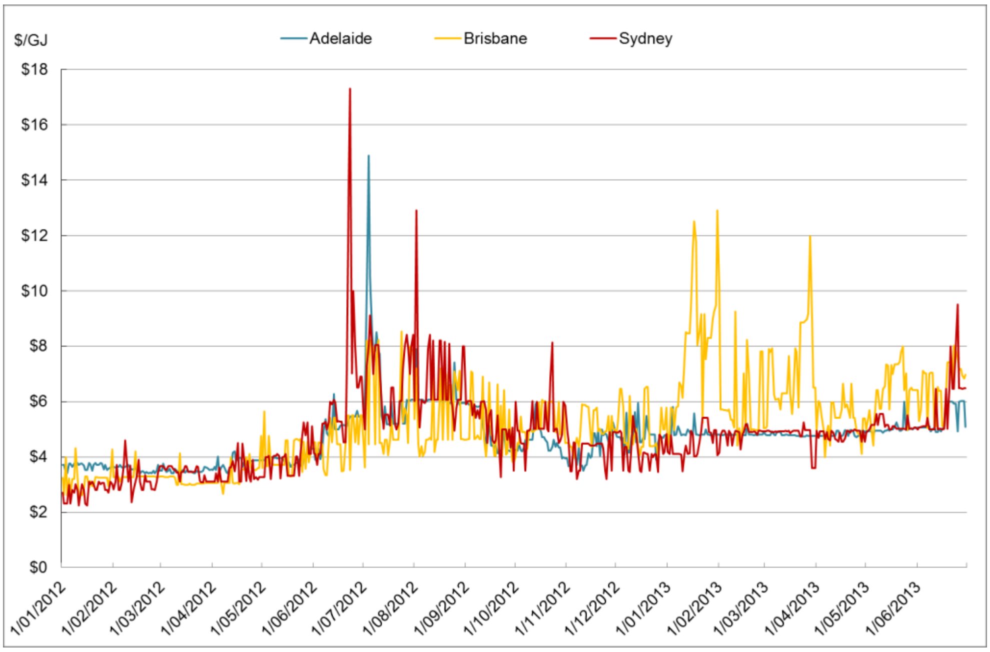
Settlement

The STTM is settled on a net basis at the end of the month and also takes into account deviation, variation and capacity charges and credits for MOS and contingency gas.

Source: AEMO, Overview of the STTM, 2011.

Figure 6.3 illustrates the path that the *ex-ante* prices in each of the STTMs have taken over the period 1 January 2012 - 30 June 2013.

Figure 6.3: Ex-ante prices in the STTM (1 Jan 2012 - 30 Jun 2013)



Source: AEMO, STTM Price and Withdrawals Data.

In a similar manner to the Victorian DWGM, the STTM *ex-ante* prices exhibit a significant degree of variability. The Adelaide and Sydney STTMs also exhibit a distinct seasonal trend, with prices peaking in winter and reaching their lows in summer. The story is somewhat different in the Brisbane STTM.

Until the end of 2012, prices in the Brisbane STTM were closely tracking those in Sydney and Adelaide, although the peaks reached in winter weren't as significant as those observed in Sydney and Adelaide.[160] In the first three months of 2013, however, prices in Brisbane increased substantially and were significantly higher than those observed in the Sydney and Adelaide STTMs. In its weekly gas market reports, the AER noted that the higher prices in Brisbane corresponded to: [161]

- an increased demand for gas by generators in Queensland; and
- higher upstream prices in Queensland, which was prompting buyers outside the STTM hub to purchase gas from the hub because it was cheaper than buying gas from a producer.

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160 This is not surprising given residential demand accounts for such a small proportion of demand in Queensland (see Figure 3.2).

161 AER, Weekly Gas Market Report, 6—12 January 2013 and 27 January – 2 February 2013.

In terms of the overall size of the STTMs, when measured on the basis of scheduled *ex-ante* quantities, Sydney is the largest, followed in declining order by Brisbane and Adelaide. In terms of traded volumes, estimates developed by Deloitte indicate the following: [162]

- 12% of the gas supplied to Adelaide over the period 1 July 2011-30 June 2012 was traded in the STTM and around 7% was traded between different parties;
- 8% the gas supplied to Sydney over the same period was traded through the STTM with around 4% traded between different parties; and
- 5% of the gas supplies in Brisbane over the period 1 December 2011 – 30 June 2012 was traded through the STTM with around 3% traded between different parties.

6.3 Wallumbilla Gas Supply Hub

In December 2012, SCER announced that a new voluntary brokerage hub would be established at Wallumbilla by March 2014.[163] The design of this hub has been developed by AEMO and will essentially involve the development of a web-based exchange platform that will facilitate the matching and clearing of trades between buyers and sellers at three different trading nodes (ie, the SWQP, QGP and RBP).[164] The types of products that are expected to be traded through the hub include a day-ahead product,[165] a balance of day product[166] and potentially, a monthly forward product.

AEMO expects the implementation of this hub to:[167]

- enhance the transparency of gas trading;
- improve the ability of participants to allocate and price gas efficiently in the short term;
- support the efficient trade and movement of gas between regions; and
- support the development of a financial product that can be used to manage risk.

There are, however, some known limitations of the hub. One of the more significant of which is that not all of the pipelines servicing Wallumbilla are physically connected. It is for this reason that AEMO proposes the development of three separate trading nodes.

The lack of physical interconnection, coupled with the fact that only a few participants are currently in a position to transport gas between the trading nodes (ie, because they have the necessary transportation and ancillary services contracts in place), means that the pool of

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162 Deloitte, Assessment of the East Coast gas market and opportunities for long-term strategic reform, May 2013, p.44.

163 SCER Communiqué, 14 December 2012.

164 AEMO, Detailed Design for a Gas Supply Hub at Wallumbilla, 19 October 2012.

165 The day ahead product will be for supply over a single gas day. The trading window for this product will commence four calendar days prior to the gas day and will close at the end of the trading day preceding the delivery day. The minimum size of this product will be 1 TJ.

166 The balance of the day product will be for supply from the hour after the time of the transaction through to the end of the gas day. The trading window for this product will be during the gas day.

167 AEMO, Detailed design for a gas supply hub at Wallumbilla, 19 October 2012, p.4.

potential buyers and sellers will be divided across the three trading nodes. The division of what is already a relatively small group of buyers and sellers will limit the degree of liquidity that can be achieved in the market and could also give rise to significant price variations across the three trading nodes.

AEMO is aware of this limitation and has noted it could, to some extent, be addressed if the brokerage model was extended to include a new range of hub services that would enable parties that don't currently have the contractual rights to transport gas across the hub to do so. The two hub services that AEMO has identified as being of particular importance in the initial stages of the supply hub's life are redirection[168] and compression[169] services. Other hub services AEMO has noted could evolve over time are balancing, storage and processing services.[170]

The ability of participants to utilise the pipelines servicing Wallumbilla that they don't currently have contractual rights to use, is also viewed as critical to the success of the hub. AEMO therefore proposes to: [171]

- introduce a Bulletin Board style capacity trading mechanism, which will enable participants to advertise their interest in buying and selling pipeline capacity; and
- try to develop standardised terms for capacity trading, as a means of reducing transaction costs.

The options for encouraging a greater degree of capacity trading across eastern Australia have also recently been canvassed in SCER's Gas Transmission Pipeline Capacity Trading Consultation Regulation Impact Statement (RIS). The four options contemplated include:[172]

- no change to the current arrangements;
- improved information and standardisation of contract terms and conditions – this proposed option would involve both:
  - the publication of additional information on unused pipeline capacity (close to real-time utilisation data and end of day/week utilisation data) on either the Bulletin Board or on the pipeline owners' websites; and
  - the development of standardised contract terms and conditions to facilitate trade and expedite the transfer of title process.
- a voluntary capacity trading platform operated by either a government body, pipeline owner or a third party; and
- a mandatory trading obligation, which would involve compelling either:

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168 A redirection service would essentially just involve a swap of gas across locations.

169 AEMO has noted that a compression service may be required to redirect gas to alternate delivery locations.

170 AEMO, Gas Supply Hub – Cost and Scoping Report, 4 May 2012, p.14.

171 AEMO, Detailed Design for a Gas Supply Hub at Wallumbilla, 19 October 2012, p.5.

172 SCER, Regulation Impact Statement – Gas Transmission Pipeline Capacity Trading Consultation Paper, May 2013, piii.

- pipeline owners to offer up unused capacity on an 'as available' basis if shippers don't nominate their full MDQ entitlement (referred to as the use it or lose it option); or
- shippers to offer up unused firm capacity if they do not fully utilise their MDQ (referred to as the use it or sell it option).

The closing date for submissions on this Consultation RIS is mid-July and at this stage it is envisaged that a Decision RIS will be prepared for SCER's consideration at the end of 2013. While the Consultation RIS does not limit itself to capacity trading issues on the pipelines servicing Wallumbilla, the timing of the proposed Decision RIS would tend to suggest that any remedy identified in the decision RIS could be put in place either before the hub commences or shortly thereafter.

While SCER has only given approval for the development of a supply hub at Wallumbilla, AEMO has noted the potential for other supply hubs to be developed in eastern Australia at major production regions.[173]

[173] AEMO, Detailed design for a gas supply hub at Wallumbilla, 19 October 2012, p.4.

7. Institutional, Regulatory and Emergency Arrangements

The institutional and regulatory arrangements applying to scheme (regulated) pipelines, the Bulletin Board, the DWGM and the STTM are set out in both the National Gas Law (NGL) and the National Gas Rules (NGR). The arrangements applying to retail markets in those jurisdictions that have implemented the National Energy Customer Framework (NECF), on the other hand, are set out in the National Energy Retail Law (NERL) and the National Energy Retail Rules (NERR). The remainder of this chapter provides an overview of these institutional and regulatory arrangements. This chapter also outlines the arrangements that have been put in place to deal with gas emergencies affecting more than one jurisdiction.

7.1 Summary of arrangements

The functions and responsibilities of those institutions that have a key role to play in the transportation segment of the gas supply chain, the facilitated markets and retail markets are outlined below:[174]

- *Policy direction* – SCER is the energy market governance body and is responsible for developing and administering the legislative framework and providing policy direction.
- *Market development and rule-making* – the AEMC is responsible for making and amending the NGR and the NERR, market development, providing advice to SCER and maintaining the gas pipeline scheme register.
- *Pipeline coverage and form of regulation* – the National Competition Council (NCC) is responsible for making recommendations to the relevant minister on coverage applications and deciding on the form of regulation to apply to scheme pipelines (ie, light or full regulation) if an application is made for this to be altered.
- *Economic regulation and enforcement* – the AER is responsible for the economic regulation of scheme pipelines in eastern Australia and the Northern Territory, monitoring trading activity in both the DWGM and STTM, monitoring compliance with, and investigating breaches of, the NGR and has a range of functions under the NERR. The economic regulation of scheme pipelines in Western Australia is the responsibility of the Economic Regulation Authority (ERA).
- *Market operator* – AEMO is responsible for a range of functions including, amongst others, operating the DTS, operating, administering and improving the effectiveness of the DWGM and the STTMs, operating and maintaining the Bulletin Board, preparing the GSOO, providing planning advice in Victoria and being the retail market operator in NSW, the ACT, Queensland, South Australia and Victoria.
- *Appeals bodies* – the Australian Competition Tribunal is responsible for conducting merits based reviews on reviewable regulatory decisions under the NGL and NGR while the Federal Court of Australia is responsible for carrying out judicial reviews.

[174] In addition to these institutions a number of jurisdictional economic regulators and technical regulators have various responsibilities under state based legislation.

Table 7.1 provides a snapshot of the regulatory and emergency arrangements applying to transmission pipelines, distribution pipelines, the facilitated markets and retail markets.

Table 7.1: Snapshot of regulatory and emergency arrangements

Type of regulation		Transportation Segment		Market	
		Transmission pipelines	**Distribution pipelines**	**Facilitated market**	**Retail market**
Economic regulation	**General competition laws**	Commonwealth *Competition & Consumer Act 2010* applies across all sectors			
	Gas pipeline regulation (ie, of services, prices, access)	NGL and NGR provisions for scheme pipelines only Potential state/territory licences, codes, other rules		n/a	n/a
	Retail regulation	n/a	NECF or state/territory regulation in non-adoptive jurisdictions	n/a	NECF or state/territory regulation in non-adoptive jurisdictions
			AEMO Retail Gas Market Procedures		AEMO Retail Gas Market Procedures
					Potential state/territory price regulation
	Bulletin Board	NGL and NGR for pipelines deemed to be BB facilities	n/a	n/a	n/a
	Facilitated market regulation	n/a	n/a	NGL and NGR provisions for STTM (Adel, Bris and Syd) DWGM (Vic)	n/a
System operation	**Integrated market and system operation**	DWGM (Vic)	n/a	n/a	n/a
	Safety requirements	Commonwealth, state, territory technical regulation		n/a	n/a
Emergency	**Cross border emergency**	National Gas Emergency Response Protocol			
	State and territory emergencies	Each jurisdiction has emergency powers that override other regulatory and contractual obligations			

7.2 Regulation of gas pipelines

The regulatory framework applying to scheme (regulated) pipelines is set out in the NGL and the NGR, both of which came into effect on 1 July 2008. Prior to 1 July 2008, scheme pipelines were subject to the regulatory framework set out in the *Gas Pipeline Access (South Australia) Act 1997* (GPAL) and the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Gas Code), which were introduced in 1997.

One interesting point to note about the regulatory framework adopted in the NGL and NGR (and their predecessors) is that it is more in keeping with the negotiate-arbitrate model set out in *Part IIIA of the Competition and Consumer Act 2010*, than the regulatory framework adopted in electricity. This point of distinction can be seen in the following extract taken from the introduction to the Gas Code:

> "The aim of the Code is to provide sufficient prescription so as to reduce substantially the number of likely arbitrations, while at the same time incorporating enough flexibility for the parties to negotiate contracts within an appropriate framework."

Some other important points of distinction between the regulatory frameworks adopted in gas and electricity are that:

- the economic regulatory framework in the NGR only applies to scheme pipelines;
- scheme pipelines may be subject to either full or light regulation;[175] and
- provision has been made for a pipeline's coverage status and/or the form of regulation to be altered over time if conditions change and certain criteria are met.

The current regulatory status of major transmission and distribution pipelines in eastern Australia, Western Australia and the Northern Territory is set out in Table 7.2.

Table 7.2: Regulatory status of major transmission and distribution pipelines

	Pipeline name and owner	Regulatory status
	Distribution pipelines	
NSW& ACT	New South Wales Gas Distribution Network	Regulated
	ActewAGL Gas Network	Regulated
	Wagga Wagga Gas Network	Regulated application for revocation of coverage currently before the NCC
Vic	Envestra - Victorian Gas Distribution Systems	Regulated
	Multinet - Gas Distribution Network	Regulated
	SP AusNet - Gas Distribution Network	Regulated
SA	South Australian Gas Distribution System	Regulated – designated pipeline
Qld	Allgas Energy Distribution System	Regulated
	Envestra Distribution System	Regulated
Tas	Tasmanian Distribution System	Unregulated
WA	Alinta Gas Distribution System	Regulated by ERA – designated pipeline
NT	Darwin Distribution System	Unregulated

175 The only exception to this is if the scheme pipeline has been deemed a 'designated pipeline'. See footnote 182.

	Pipeline name and owner	Regulatory status
	Transmission pipelines	
NSW& ACT	Moomba to Sydney Pipeline (MSP)	Unregulated - Moomba to Marsden. Light regulation - remainder.
NSW& ACT	Eastern Gas Pipeline (EGP)	Unregulated
NSW& ACT	Interconnect	Unregulated on the NSW side and regulated on the Victorian side
NSW& ACT	Central West Pipeline (CWP)	Light regulation
NSW& ACT	Central Ranges Pipeline	Regulated through outcome of a competitive tender
Vic	DTS	Regulated
SA	Moomba to Adelaide Pipeline (MAPS)	Unregulated
SA	SEA Gas Pipeline	Unregulated
SA	SESA Pipeline	Unregulated
SA	South East Pipeline	Unregulated
Qld	SWQP and QSN	Unregulated
Qld	Roma to Brisbane (RBP)	Regulated
Qld	Queensland Gas Pipeline (QGP)	Unregulated
Qld	Carpentaria Gas Pipeline (CGP)	Qld Derogation states pipeline to be subject to light regulation until 2023
Qld	Dawson Valley Pipeline (DVP)	Regulated
Qld	North Queensland Gas Pipeline	Unregulated
Qld	Berwyndale to Wallumbilla Pipeline	Unregulated
Qld	Wallumbilla to Darling Downs Pipeline	Unregulated
Tas	Tasmanian Gas Pipeline (TGP)	Unregulated
WA	Dampier to Bunbury Pipeline (DBNGP)	Regulated by ERA – designated pipeline
WA	Goldfields Gas Pipeline	Regulated by ERA
WA	Dampier to Port Hedland Pipeline	Unregulated
WA	Tubridgi Pipeline System	Unregulated
WA	Midwest Gas Pipeline	Unregulated
WA	Kalgoorlie to Kambalda Lateral	Light regulation
WA	Kambalda-Esperance Gas Pipeline	Unregulated
WA	Telfer Gas Pipeline	Unregulated
WA	Parmelia Gas Pipeline	Unregulated
NT	Amadeus Basin to Darwin Pipeline (ABDP)	Regulated
NT	Bonaparte Pipeline	Unregulated
NT	Wickham Point Pipeline	Unregulated
NT	Daly Waters to McArthur River Pipeline	Unregulated
NT	Palm Valley to Alice Springs	Unregulated

As the information in this table reveals, there are currently only a small number of transmission pipelines that are regulated (12 out of 33) and subject to either full (eight) or light (four) regulation. The story is somewhat different for distribution pipelines, with all but two of the networks listed in this table[176] currently subject to full regulation. In terms of the pipelines that are currently unregulated, the following applies:

- Although these pipelines are not currently subject to the economic regulatory provisions set out in the NGL and NGR, they are still subject to the general competition provisions in the *Competition and Consumer Act 2010*.

[176] Note there are a number of other smaller distribution systems that are not listed in this table, which are located in small regional areas that are not subject to any form of regulation.

- They may become subject to the economic regulatory provisions set out in the NGL and NGR if a coverage application is made to the NCC and the relevant Minister subsequently decides it should be covered.

The remainder of this section provides an overview of the economic regulatory framework applying to scheme pipelines and the process by which a pipeline's coverage status or form of regulation can be altered.

7.2.1 Economic regulation of scheme pipelines

The term 'scheme pipeline' is used in the NGL and NGR to refer to those pipelines that are subject to either full or light regulation. The obligations imposed on pipelines that are subject to full or light regulation are set out below.

7.2.1.1 Full regulation

The owner or service provider of a pipeline that is subject to full regulation is required by the NGR to periodically submit a 'full access arrangement' to the AER and obtain its approval for the proposed terms and conditions of access. In accordance with rule 48 of the NGR, the 'full access arrangement' must set out:

- the reference service(s) to be provided by the pipeline and the reference tariff payable for each reference service. The term 'reference service' is defined in the NGR as a service that is likely to be sought by a significant portion of the market. While the access arrangement specifies a reference service, the parties can negotiate and agree to the provision of a service that differs from the reference service and a different tariff to apply to that service;
- the terms and conditions upon which the reference service(s) will be provided; and
- the pipeline's queuing policy,[177] capacity trading policy,[178] extensions and expansions policy[179] and the terms on which receipt/delivery points may be changed by the shipper.

When assessing a proposed access arrangement, the AER is required to have regard to:

- the price and revenue regulation related provisions set out in Part 9 of the NGR;

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177 This policy is used to determine the order of priority for access to spare and developable capacity.

178 The capacity trading policy must enable users to transfer capacity and comply with the following:

- a user may transfer any portion of its contracted capacity to a third party through a sub contractual arrangement *without* the service provider's consent but must inform the service provider of the sub-contract and the likely duration, the identity of the third party and the amount of capacity transferred; and
- a user may transfer any portion of its contracted capacity to a third party *with* the service provider's consent. The service provider must not withhold its consent unless it has reasonable grounds for doing so.

179 The extensions and expansions policy must set out whether the applicable access arrangement will apply to incremental services to be provided as a result of a particular extension to, or expansion of, the pipeline or may allow for later resolution of that question on a basis stated in the requirements. It is worth noting that pipelines that have been deemed to be designated pipelines (ie, the South Australian Distribution Network, the DBNGP and the Alinta Gas Distribution System, any extension or expansion of the pipeline must be treated as part of the regulated pipeline. See *National Gas (South Australia) Regulations 2009* Schedule 1 and *National Gas Access (WA) (Part 3) Regulations 2009,* Schedule 1.

- the national gas objective (NGO) set out in section 23 of the NGL; and
- the revenue and pricing principles set out in section 24 of the NGL.

7.2.1.2 *Light regulation*

Unlike the obligations imposed on pipelines that are subject to full regulation, a pipeline that is subject to light regulation is only required to:

- publish the terms and conditions of access, including tariffs on its website; and
- report to the AER on access negotiations.

The service provider of such a pipeline also has the option of developing a 'limited access arrangement' for approval by the relevant regulator. Unlike a 'full access arrangement', a 'limited access arrangement' does not need to incorporate provisions relating to the calculation of revenue requirements and reference tariffs.

The only additional obligation imposed on the service provider of a light handed regulation pipeline is that it is prevented from engaging in price discrimination by section 136 of the NGL.

7.2.1.3 *Dispute resolution provisions and other provisions applying to scheme pipelines*

Irrespective of whether a pipeline is subject to full or light regulation, shippers and prospective shippers can have recourse to the dispute resolution mechanism set out in the NGL (Chapter 6) and the NGR (Part 12) if a dispute about access, or the terms and conditions upon which access to these pipelines will be granted, arises. If such a dispute arises, the prospective user or service provider may notify the dispute resolution body (the AER or the ERA in WA) in writing. The dispute resolution body may then require the parties to mediate, conciliate or engage in other alternative dispute resolution processes to resolve the dispute.

Other provisions that apply equally to pipelines that are subject to full or light regulation are the facilitation of, and request for, access rules set out in Part 11 of the NGR. Amongst other things, these provisions require service providers to:

- make available the applicable access arrangement (where relevant) and other information to prospective users;
- respond to any access request made by a prospective user within a defined period and provide a prospective user with information about the tariff that would apply to the service sought by the prospective user, if it is commercially and technically feasible to provide that service; and
- maintain a public register of spare capacity.

These provisions also require the *users* of full and light regulation pipelines to respond to any request for information about whether any of their unutilised contracted capacity is, or is likely to, become available and, if so, the terms and conditions upon which it would be prepared to transfer the unutilised capacity.

7.2.2 Coverage and form of regulation decisions

Provision has been made in the NGL for a pipeline's coverage status and/or the form of regulation to be changed over time if certain criteria are satisfied. Provision has also been made in the NGL for greenfield pipelines to obtain a '15 year no coverage' determination if certain criteria are satisfied. An overview of these provisions is provided below.

7.2.2.1 Coverage decisions

An application for a coverage or revocation of coverage determination can be made by any person to the NCC. Once such an application is received, the NCC is required to assess the application and make a recommendation to the relevant Minister.[180] In making its recommendation, the NCC is required to give effect to the following coverage criteria:[181]

- access (or increased access) to the services provided by the pipeline would promote a material increase in competition in at least one other market;
- it would be uneconomic to develop another pipeline to provide the services;
- access can be provided without undue risk to human health or safety; and
- access (or increased access) would not be contrary to the public interest.

The NCC is also required to have regard to the NGO. If the NCC recommends coverage, it must also make a decision about whether the pipeline will be subject to full or light regulation. A decision as to whether a pipeline should be covered must ultimately be made by the relevant Minister having regard to the coverage criteria, the NGO and the NCC's recommendation.

7.2.2.2 Form of regulation decisions

For pipelines that are covered and are not 'designated',[182] an application may be made to the NCC seeking a change in the form of regulation to apply to that pipeline. Unlike a decision on coverage, which must be made by the relevant Minister, a decision as to whether full or light regulation should be applied can be made by the NCC. In making such a decision, section 122 of the NGL requires the NCC to have regard to:

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[180] The identity of the 'relevant Minister' will depend on whether the pipeline is a transmission or distribution pipeline and if the pipeline crosses jurisdictions. For example, if the pipeline is a cross boundary transmission pipeline, the relevant Minister is the Commonwealth Minister but if the transmission pipeline is situated wholly within a jurisdiction, the relevant Minister will be the State or Territory Minister. For applications relating to distribution pipelines situated wholly within a jurisdiction, the relevant Minister will be the State or Territory Minister while for cross boundary distribution pipelines, the relevant Minister will be the Minister in the jurisdiction that the pipeline is most closely connected. See definitions section of NGL.

[181] The interpretation of some of these criteria is currently being considered by the Productivity Commission as part of its review of the National Access Regime.

[182] A designated pipeline is a pipeline classified by the Regulations, or designated in the application Act of a participating jurisdiction, that cannot be subject to light regulation (see sections 109 and 111 of the NGL). In accordance with section 11 of the NGL, once a regulation has been made by the Governor, which prescribes a designated pipeline the Governor cannot make another regulation that prescribes any other pipeline to be a designated pipeline. The only pipeline currently referred to in the *National Gas (South Australia) Regulations 2009* as being designated is Envestra's South Australian Distribution Network. In Western Australia, the DBNGP and the Alinta gas distribution system have also been deemed designated pipelines (see *National Gas Access (WA) (Part 3) Regulations 2009,* Schedule 1).

- the likely effectiveness of the alternative forms of regulation to promote access;
- the costs that may be incurred by an efficient service provider, efficient users and prospective users and end-users under the alternative forms of regulation; and
- the NGO, the form of regulation factors and any other matters it considers relevant.

7.2.2.3 '15 year no coverage' determinations for greenfield investments

To provide some degree of regulatory certainty for greenfield investments, the NGL allows interested parties to make an application to the NCC seeking a '15 year no coverage' determination.[183] In a similar manner to the coverage provisions, the NCC is required to assess such an application having regard to the coverage criteria and the NGO and to make a recommendation to the relevant Minister. The Minister must then decide whether or not to make such a determination, having regard to the coverage criteria, the NGO and the NCC's recommendation.

To date, the only pipelines that have sought and been granted a '15 year no coverage determination', are the three pipelines being constructed by the LNG proponents, to link their facilities in the Bowen/Surat basins with the LNG facilities at Gladstone.

7.2.3 Merits review

A merits review mechanism[184] has been included in the NGL to enable those parties affected by the following types of decisions to have the decision reviewed on its merits by the Australian Competition Tribunal:

- an access arrangement decision by the AER;
- a Ministerial coverage decision; and
- light regulation related determinations by the NCC.

The merits review provisions are set out in Part 5 Division 2 of the NGL.

7.3 Regulation of the Bulletin Board

The regulatory arrangements applying to the Bulletin Board are set out in Chapter 7 of the NGL and Part 18 of the NGR. Unlike the economic regulatory provisions, which only apply to scheme pipelines, these provisions apply to a broader group of transmission pipelines, production and storage facilities in eastern Australia.[185]

In short, the Bulletin Board provisions set out in the NGL and NGR require:

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183 MCE, Regulatory Impact Statement – Gas Access Regime – Greenfields Incentives, November 2005.

184 It is worth noting that unlike the electricity regulatory framework in existence before the NEL and NER, the Gas Code also included a merits review mechanism.

185 Note that the decision to apply economic regulation to a pipeline is independent of its status as a Bulletin Board pipeline. It is quite feasible that a pipeline is a Bulletin Board pipeline and provides info to AEMO on that basis while not being subject to any regulatory oversight by the AER at all.

- AEMO to operate and maintain the Bulletin Board, develop procedures and notify the AER of any breaches, or possible breaches, of this part of the NGR; and
- operators of pipelines, production and storage facilities that are deemed to be Bulletin Board facility operators to provide AEMO, at the start of each gas day, with information on the facility's name place rating, a three day capacity outlook and actual utilisation data. Pipeline operators are also required to provide aggregated information on nominations, forecast and actual deliveries.

Provisions in Part 18 of the NGR also allow Bulletin Board participants to notify other users if they have spare pipeline capacity or gas available for purchase, or if they wish to purchase additional gas or spare capacity. This part of the Bulletin Board has not, however, been used to date.

7.4 Regulation of the DWGM

The regulatory and institutional arrangements underpinning the operation of the DWGM are set out in Part 6 of the NGL, parts 15A and 19 of the NGR and a number of procedures developed by AEMO. The institutional arrangements can be briefly summarised as follows:

- AEMO is both market and system operator and is therefore responsible for:
  - operating the DTS, managing system security, reliability and safety and preparing an annual planning review for the DTS;[186] and
  - operating and administering the DWGM and developing any procedures that may be required for this market.
- the AEMC is responsible for assessing any proposed rule changes, which, in accordance with section 295(3)(a) of the NGL can only be made by AEMO or the Victorian Minister for Energy and Resources; and
- the AER is responsible for monitoring trading activity in the DWGM and reporting on significant price variations.

The rules in Part 19 of the NGR set out:

- who is to be registered to participate in the DWGM;
- how the DWGM is to operate in terms of system security, the physical movement of gas, nominations and bidding, scheduling, setting the wholesale market price, allocations, the market settlement process, prudential requirements, intervention and market suspension;
- the MDQ authorisation process;
- the arrangements to be followed in an emergency;
- the requirement for the AER to monitor trading activity in the DWGM;
- the dispute resolution mechanism; and

[186] The terms on which the DTS is made available by the owner of the DTS to AEMO are set out in a service envelope agreement that has been entered into between AEMO and the owner of the DTS.

- the consultation process to be followed by AEMO if a proposal is made to amend any of the rules in Part 19.

7.5 Regulation of the STTM

The regulatory and institutional arrangements underpinning the operation of the STTM are set out in Part 6 of the NGL, parts 15A and 20 of the NGR and AEMO's STTM Procedures. The institutional arrangements can be briefly summarised as follows:

- AEMO is the market operator and responsible for operating and administering the STTM and developing any procedures that may be required for this market;
- the AEMC is responsible for assessing any proposed rule changes, which unlike the DWGM can be submitted by any person; and
- the AER is responsible for monitoring trading activity and reporting on significant price variations in the STTM.

The rules in Part 20 of the NGR, currently set out:

- the hubs at which the STTM applies;
- the registration process for the STTM;
- how the STTM is to operate in terms of scheduling, pricing, allocations, market schedule variations, deviations, the market operator service, contingency gas, the market settlement process and prudential requirements;
- the market reviews to be carried out by AEMO;
- the requirement for the AER to monitor trading activity in the STTM; and
- the dispute resolution mechanism.

7.6 Regulation of retailers and retail markets

There are a variety of technical and non-technical regulatory arrangements applying to retailers and retail markets. The remainder of this section provides a high level overview of the more significant non-technical regulatory arrangements.

7.6.1 National Energy Customer Framework

In late 2006, the MCE's Retail Policy Working Group commenced work on the development of a national consumer protection framework for the retail sale and supply of electricity and gas to residential and other small customers (and a range of related reforms). The framework, which was finalised in 2011 and given effect through the NERL, NERR and National Energy Retail Regulations, deals with, amongst other things:

- the retailer-customer relationship, the rights and obligations of both parties and consumer protection measures;
- the model terms and conditions for standard retail contracts;

- how distributors should interact with customers and retailers, the rights and obligations of these parties during such interactions and consumer protection measures; and
- the process for obtaining a retailer authorisation, which replaces the jurisdictional licencing arrangements.

In accordance with the NERL, the AEMC is responsible for rule making and market development, while the AER is responsible for:

- authorising retailers to sell energy;
- monitoring and enforcing compliance with the NERL, NERR and regulations;
- reporting on the performance of the market and energy businesses;
- approving the policies energy retailers are required to implement to assist customers facing financial hardship; and
- administering a national retailer of last resort scheme.

The NECF replaces existing jurisdictional arrangements in those states and territories where it is implemented. At the time of preparing this report:

- the ACT, Tasmania, South Australia and NSW have implemented NECF;
- Victoria has indicated it will implement NECF as soon as practicable;
- Queensland is yet to make a formal decision on whether it will implement NECF; and
- Western Australia and the Northern Territory have decided not to implement NECF.

In those jurisdictions that have not implemented NECF, the jurisdictional licencing and other retail regulatory arrangements remain in place.

7.6.2 Retail price regulation

NSW is currently the only jurisdiction in eastern Australia that regulates retail gas prices under standard contracts. However, this could change in the future if the AEMC's draft recommendation to remove retail price regulation in NSW is accepted by the NSW Government.[187] Across the other jurisdictions, the regulation of retail gas prices was either never introduced (eg, Tasmania) or has been removed (eg, Victoria removed retail price regulation on 1 January 2009 while South Australia removed it on 1 February 2013).

7.6.3 Retail market operations

AEMO is the retail market operator in NSW, the ACT, Queensland, South Australia and Victoria and in this capacity administers the provision of the following services:

[187] The body responsible for regulating retail gas prices is the NSW Independent Pricing and Regulatory Tribunal (IPART).

- delivery point management, which involves managing customer transfers for gas delivery points and the associated market data between retailers, and between retailers and distribution businesses;
- balancing, allocation and reconciliation management, which involves managing the daily allocation of gas usage to retailers to enable settlement of gas supply contracts, transmission and distribution use of system contracts; and
- operation of the IT systems that facilitate retail market services.

The provision of these services is governed by retail gas market procedures, which have been developed by AEMO in accordance with rule 135EA of the NGR.

7.7 Summary of economic regulation and market arrangements

Table 7.3 sets out the regulatory and market arrangements currently in place in each jurisdiction in eastern Australia.

Table 7.3: Economic regulation and market arrangements in eastern Australia

		NSW/ACT	Queensland	South Australia	Tasmania	Victoria
Pipelines						
Pipeline carriage model	Model	Contract carriage				Market carriage
	Pipeline characteristic	*Point-to-point*	*Point-to-point -some with multiple injection/withdrawal points*	*Point-to-point*	*Point-to-point*	*Meshed network*
Form of pipeline regulation*	Transmission	MSP - light regulation btw Marsden and Syd & unregulated between Moomba and Marsden EGP unregulated	RBP and DVP full regulation CGP light regulation SWQP/QSN, QGP and all others unregulated	MAPS and SEA Gas Pipeline unregulated	TGP unregulated	DTS full regulation
	Distribution	Full regulation in capital cities				
Facilitated markets						
Imbalance markets	Market	Sydney STTM	Brisbane STTM	Adelaide STTM	n/a	DWGM Integrated physical system and imbalance market
	Residential consumption	*31% of demand*	*3% of demand*	*13% of demand*	*Negligible*	*57% of demand*
	Variability in demand	*Reasonable degree of variation*	*Relatively flat*	*Moderate degree of variation*	*Relatively flat*	*Significant degree of variation*
Other markets		n/a	Wallumbilla supply hub under development	n/a	n/a	n/a
Retail Markets						
Retail price regulation	Residential and SMEs	Regulated in NSW up to 1 TJ threshold	Unregulated	Unregulated	Unregulated	Unregulated
	Large customers	Unregulated				

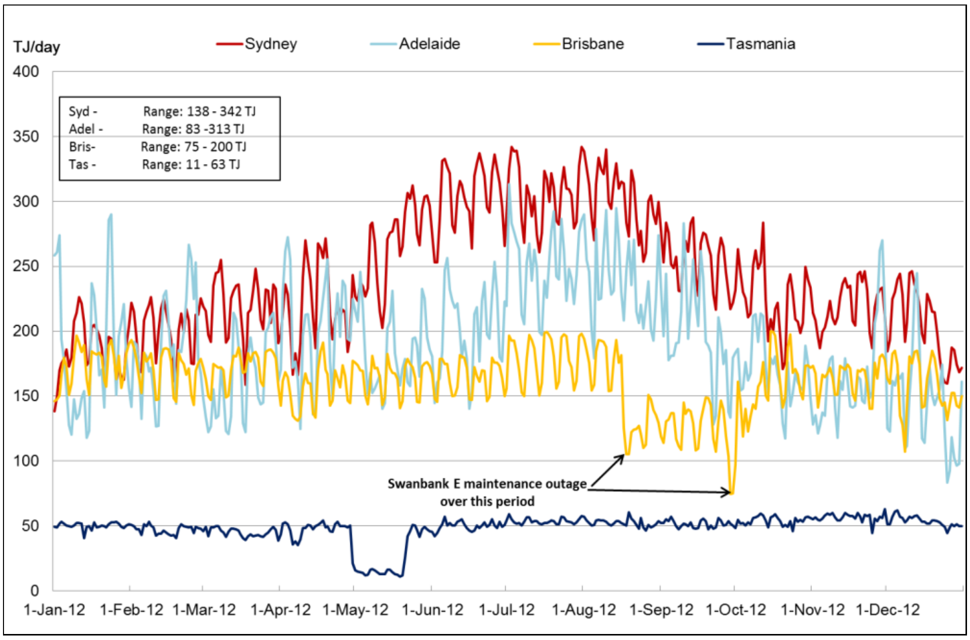
*Irrespective of the form of pipeline regulation, all pipeline owners are subject to the *Competition and Consumer Act 2010.*

As this table reveals, there are some notable differences between the regulatory and market arrangements applying in each jurisdiction. In most cases, these differences can be explained by the different physical characteristics (ie, pipeline characteristics and nature of demand) exhibited in each jurisdiction. For example:

- *Market carriage vs contract carriage:*
  - the decision to adopt the market carriage model and DWGM in Victoria was made because of the DTS' physical attributes (ie, it is essentially a meshed network) and the nature of demand in Victoria (ie, a large proportion of demand is accounted for by residential heating load, which is highly variable). The decision was also made to try to facilitate the entry of new retailers, which was considered of some importance given the large number of residential and SME customers and the volume of gas consumed by this sector (see Figure 3.2); and
  - the continued practice of using the contract carriage model in all other jurisdictions occurred because the transmission pipelines in the remainder of eastern Australia are operated on a point-to-point basis and so it is easier to identify and sell firm capacity rights.
- *Form of regulation* – whether or not a pipeline will be regulated will depend on whether it satisfies the coverage criteria (see section 7.2.2.1), but in general, if there is more than one pipeline competing to supply a location, then it will be more difficult to establish that access is required to promote a material increase in competition in another market as required by criterion (a). In those locations serviced by more than one pipeline, the pipelines tend therefore to either be subject to no regulation (eg, the MAPS and SEA Gas Pipelines in South Australia) or light regulation (eg, the MSP).
- *Imbalance markets* – in general, these markets will be of most value in locations that:
  - exhibit a reasonable degree of variability in demand, because the market mechanism can be used to help participants manage their exposure to this variation; and
  - are of sufficient scale to warrant the implementation, because the direct and indirect costs associated with these markets can be significant; and
  - have a retail market that is of a sufficient scale to attract new entry, which can, in theory, be facilitated by an imbalance market.

  These three criteria explain why the STTM has been introduced in Sydney and Adelaide but not, for example, in Tasmania, where demand is relatively flat and consumption low. In Brisbane, the case for introducing the STTM is less clear, given demand is relatively flat (see Figure 7.1) and residential and SME's consume less than 3 PJ pa.

Figure 7.1: Demand in Sydney, Adelaide, Brisbane and Tasmania (2012)



Source: Based on actual flow data from the National Gas Bulletin Board and Stanwell, Media Release – Maintenance overhaul to ensure power station's ongoing reliability, 17 August 2012.

One other factor that has influenced regulatory and market design to date has been the recognition that gas and transportation services are typically sold under medium to long term contracts. This is starting to change though with the development of the Wallumbilla gas supply hub, which is intended to operate as a spot/short term commodity market.

7.8 Emergency arrangements

Each jurisdiction in Australia has its own emergency powers that can be exercised by a Minister or agency during an emergency. The Commonwealth, states and territories have also developed the National Gas Emergency Response Protocol (Protocol), which is set out in a non-binding Memorandum of Understanding. The purpose of the Protocol is to facilitate the efficient, effective and nationally consistent management of emergencies extending beyond a single jurisdiction.[188]

In short, the Protocol:

- recognises that commercial arrangements should be allowed to operate, as far as possible, to address any shortfall in supply and maintain system security, and that the exercise of a jurisdiction's emergency powers should only occur as a last resort;
- provides for the establishment of the National Gas Emergency Response Advisory Committee (NGERAC) and sets out the functions and roles it is to play;
- specifies the principles that should guide SCER and the jurisdictions when considering the advice of NGERAC and any potential use of jurisdictional emergency powers; and

188 This protocol has been given effect through the Memorandum of Understanding - National Gas Emergency Response Protocol for Natural Gas Supply Shortages Affecting Jurisdictions with Interconnected Gas Supply Networks (MOU), which was entered into in 2005.

- sets out the consultation that should occur between affected jurisdictions in an emergency.

The Protocol came into effect in 2005 and shortly thereafter NGERAC was established and accorded responsibility for:[189]

- advising SCER and the jurisdictions in emergencies affecting more than one jurisdiction, on efficient and effective responses to, and the management, of the emergency. Amongst other things, NGERAC is expected to advise SCER and the jurisdictions on whether commercial arrangements (including contingency gas in the STTM), or other measures, may lessen, or avoid, the need to mandate reductions through the exercise of jurisdictional emergency powers;
- assessing the risk and impacts of major gas supply shortages and working with the jurisdictions, industry and users to develop and test arrangements, protocols and other measures to respond to, and mitigate the effect of, major supply shortages;
- advising SCER and the jurisdictions on:
  - the circumstances that could trigger the use of emergency powers;
  - the development of efficient gas curtailment tables and efficient options for commercial gas sharing arrangements between interconnected jurisdictions; and
  - protocols for communication of information and decisions; and
- carrying out a number of other related advisory functions.

NGERAC is currently chaired by the Commonwealth DRET while secretariat services are provided by AEMO. Other members of NGERAC include industry, user and jurisdictional representatives.[190] In addition to providing secretariat services, AEMO is responsible for providing NGERAC with:

- emergency management co-ordination services; and
- advice on emergency responses and information, analytical support, and real time modelling support during an emergency and during tests.

AEMO is also expected to provide advice on the implications of gas emergencies for the NEM and is understood to have carried out some testing in this regard.

While NGERAC has an important role to play in advising jurisdictions during an emergency, a decision as to whether a jurisdiction's emergency powers will be exercised and the end-users that should be curtailed, will ultimately be made by the affected jurisdictions.

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189 Memorandum of Understanding - National Gas Emergency Response Protocol for Natural Gas Supply Shortages Affecting Jurisdictions with Interconnected Gas Supply Networks, May 2005, Section 13.

190 Neither the AER nor the AEMC have a role to play in NGERAC or the management of gas related emergencies, more generally.

Where an emergency only affects a single jurisdiction, the mechanisms set out in the Protocol will not come into effect and the affected jurisdiction will be solely responsible for managing the emergency. In Victoria, the responsibility for managing such emergencies rests with AEMO (as market and system operator in the DWGM) and it can seek the intervention of the Victorian Government if it reasonably considers the actions available to it are not adequate to alleviate the emergency. In other jurisdictions the responsibility rests with either a Minister or government department(s).[191]

If the emergency powers are exercised in a jurisdiction, the force majeure provisions in gas supply and transportation contracts will tend to be triggered relieving producers and/or pipeline owners of their contractual obligations. The financial and commercial risks associated with emergencies tend therefore to sit with customers.

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[191] Energy Security Working Group, Recommendations on the Role of AEMO and the Effectiveness of Current Gas and Electricity Emergency Arrangements, undated, Appendix 4.

PART B:
Scoping Study Findings

8. Purpose of the Scoping Study

The eastern Australian gas market is currently undergoing a significant transformation, with a number of fundamental changes occurring on both the demand- and supply-sides of the market (see chapter 4). The precise effect that these changes will have on the market is at this point unclear, given the uncertainties currently surrounding when new sources of supply will be brought on line and the future for climate change policies. However, there is a general perception in the market that conditions will continue to tighten in the short to medium term and that gas prices will continue to converge toward the LNG netback level. Some market commentators have also noted the potential for a supply shortfall to emerge as early as 2015.[192]

It is against this backdrop that the AEMC has decided to undertake the gas market scoping study, the purpose of which is to:

- review, at a high level, the existing regulatory and market arrangements applying to the supply of gas from the time it enters a gas transmission pipeline to the time it is delivered to end-users;
- engage with stakeholders to get a better understanding of how well they think the current arrangements are working and to get their perspectives on whether any improvements could be made that would better promote the NGO;
- identify areas of potential improvement in the current regulatory and market arrangements that could promote efficiency in the long term interests of consumers and that may benefit from more detailed market development work; and
- better understand the strategic framework and direction of the gas market to inform its consideration of how individual rule changes contribute to that direction.

While it is clear that a study of this nature will not address the more fundamental upstream supply issues currently affecting the market, there is, in our view, still value in standing back and taking stock of the existing market and regulatory arrangements and considering the extent to which:

- the current arrangements are likely to continue to support the efficient movement and trade of gas in eastern Australia given the changes currently underway in the market;
- the contract carriage and Victorian market carriage models, and the gas pipeline regulatory arrangements are promoting efficient investment in, operation and use of gas pipelines;
- the facilitated markets are encouraging the efficient trade of gas; and
- greater interoperability, risk management and consistency between the gas and electricity markets are required.

192 See for example, AFR, Dim future for gas supply, 27 May 2013.

One other important point worth noting in this context, is the range of other studies currently being undertaken by DRET, BREE, AEMO and the Peter Reith Task Force that are examining upstream supply issues (see section 4.5). This scoping study may therefore be viewed as complementing the work that is being carried out by these parties.

The remainder of this part of the report is structured as follows:

- chapter 9 outlines the assessment framework that we have used to carry out the scoping study;
- chapter 10 provides an overview of the issues raised by stakeholders; and
- chapter 11 sets out assessment of the current arrangements and our recommendations.

9. Assessment Framework

The purpose of the scoping study is, as noted in chapter 8, to:

- undertake a high level review of the existing regulatory and market arrangements applying to the supply of gas from the time it enters a gas transmission pipeline to the time it is delivered to end-users; and
- identify whether there are any specific areas of the existing market and regulatory arrangements that may benefit from future market development work, prioritise their importance and identify who may be best placed to take it forward.

Importantly, the task at this stage is *not* to identify and evaluate solutions to any identified issues. Rather, the task at this stage is to identify whether there are any issues with the current arrangements, assess the materiality of these issues and identify who may be best placed to take them forward. This study has therefore focused on the first three steps of the assessment framework set out below:

Step 1: Carry out a high level review of the current regulatory and market arrangements and consider whether there are any particular areas of these arrangements that may benefit from further investigation and/or market development work;

Step 2: Assess the materiality of the issues identified in step 1;

Step 3: For those issues that are considered material, identify options for how the issues could be progressed and who may be best placed to take them forward (ie, SCER, the AEMC, AEMO, industry or individual market participants). Also consider the priority that should be accorded to the issue;

Step 4: Carry out a detailed review of the issues identified in step 3, determine whether there is a case for action (eg, there is a market failure or deficiencies in the existing legislative/regulatory framework) and, if so, identify the set of feasible solutions (regulatory, self-regulatory, co-regulatory and non-regulatory), having regard to:

- the NGO;
- the nature and size of the market, the physical characteristics of the market (ie, pipeline characteristics and nature of demand) and the commercial arrangements underpinning the supply and transportation of gas;
- input from stakeholders; and
- whether the solutions are targeted and proportionate to the issue they are intended to address.

Step 5: Carry out a transparent cost benefit assessment and implement one of the feasible solutions if the benefits of doing so are judged to outweigh the costs and it is consistent with the NGO.

Further detail on the matters we have considered when carrying out the first three steps is set out below.

9.1 Step 1: High level review

The first step of the assessment framework outlined above, requires a high level review of the existing market and regulatory arrangements to be carried out. In carrying out this review we have considered:

- the issues raised by stakeholders during the consultation process (see chapter 10);
- the nature and size of the market, the physical characteristics of the market and the commercial arrangements underpinning the supply and transportation of gas, all of which can influence regulatory and market design (see Part A and section 7.6); and
- how the changes currently underway in the market may test the existing arrangements.

Our review has also had regard to:

- the NGO, which is set out in section 23 of the NGL and states that the objective of the NGL is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas; and
- the two principles underlying SCER's Gas Market Development Plan, which are to ensure that supply responds flexibly to market conditions and to promote market development, through measures that are designed to:[193]
  - increase the role of markets;
  - improve the level and quality of information; and
  - improve the effectiveness of regulation.

While the principles adopted by SCER differ somewhat in their expression from the NGO, they are consistent with the allocative, productive and dynamic efficiency concepts embodied in the NGO (see Box 9.1), which are themselves based on the outcomes one would expect to observe in a workably competitive market over the long run. In such a market, workable competition over the long run can be expected to encourage:

- participants to seek out the least-cost way of producing their products/services (productive efficiency);
- prices to be driven down to the efficient cost level (allocative efficiency); and
- innovation, improvements in product/service quality and the development of new products/services (dynamic efficiency).

While on the topic of SCER's Gas Market Development Plan, it is worth noting that while reference is made to the importance of increasing the role of markets, improving the level and quality of information in the market, and improving the effectiveness of regulation, these should not, in our opinion, be viewed as objectives, in and of themselves. Rather, they should be considered in the context of the NGO. Any measures that are designed to increase

[193] SCER, Gas Market Development Plan, December 2012.

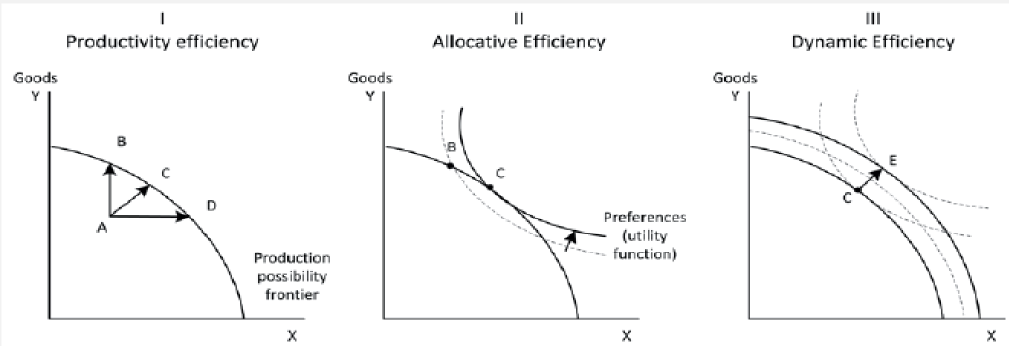
the role of markets, for example, should therefore be assessed having regard to whether they are likely to be in the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

Box 9.1: Efficiency dimensions

Economists generally recognise the following types of efficiency:

- Allocative efficiency – this term is used to refer to the situation in which society's resources are allocated between end uses in an optimal way such that the goods and services that are produced are those that are most valued by consumers. This efficiency concept requires prices that are cost reflective and is consistent with the 'efficient use of' element of the NGO.
- Productive (or technical) efficiency – this term is used to refer to goods and services being produced at the lowest possible cost, using the least-cost combination of inputs. This concept is consistent with the 'efficient operation of' element of the NGO.
- Dynamic efficiency – this term is used to refer to a market outcome in which society's resources are deployed efficiently between present and future uses, so that the welfare of society is maximised over time (ie, allocative and productive efficiency are achieved jointly over time). This term is also used to refer to the ability of firms and markets to adapt over time in response to changes in consumer preferences and/or technology by implementing measures that result in a reduction in costs, improvements in product quality and/or the development new products. This is consistent with the *long run* 'efficient investment in', 'efficient operation of' and 'efficient use of' elements.

These three dimensions of economic efficiency are illustrated in the following diagrams developed by the Productivity Commission.



Source: Productivity Commission, Staff Research Note – On Efficiency and Effectiveness: some definitions, May 2013, p.3.

In keeping with the NGO and SCER's principles, we have considered, at a high level, the extent to which the existing market and regulatory arrangements may be adversely affecting allocative, productive and/or dynamic efficiency. Some of the factors we have considered in this context are whether the existing arrangements may be:

- imposing inefficient or unnecessary costs on parties;
- exposing parties to risks that aren't allocated efficiently or can't be effectively managed;
- impeding efficient investment decisions;
- discouraging the efficient use of natural gas services;
- discouraging innovation in product and/or service provision;
- acting as a barrier to entry, or otherwise deterring competition; and/or
- failing to provide timely and accurate information that is required by the market.

9.2 Step 2: Materiality of the issues

The second step of our assessment framework considers the likely materiality of the issues identified in step 1. Given the high level nature of this scoping study, we have undertaken this assessment having regard to:

- extrinsic material, where such material is available;
- the feedback received from stakeholders during the consultation process. In considering this feedback we have been mindful of the natural incentives some stakeholders may have to raise or be silent on particular issues; and
- a subjective assessment of the likelihood that any remedy will result in a material improvement in productive, allocative and/or dynamic efficiency in the provision of natural gas services, for the long term interests of consumers.

As one would expect in such a high level study, it has not been possible to carry out a detailed assessment of the materiality of the issues or to fully test the views put forward by stakeholders. Any further work that may be carried out on the issues in Step 4, would therefore require a more detailed review of the issues and determine whether there is a case for action.

9.3 Step 3: Identify a course of action

The third step of our assessment framework considers:

- how the issues identified in step 2 as being material can be progressed (eg, through a strategic market development review, a targeted review that focuses on specific issues with the existing market and/or regulatory design or a rule change process);
- who is best placed to take the lead on each issue and who is best placed to undertake any detailed work, with the options including SCER, DRET, the AEMC, AEMO, industry or individual market participants; and
- the priority that should be accorded to the issue.

In considering the second of these issues, we have been mindful of both:

- the different roles and responsibilities that government, the AEMC and AEMO have in the gas market and the circumstances in which it will be appropriate for any of these parties to progress particular issues, ie:
  - government should take the lead, or be involved in the implementation of the solution, if there is a market failure,[194] or a deficiency in the existing legislative provisions;
  - the AEMC should take the lead on market development work and be responsible for conducting any reviews into the the operation and effectiveness of the NGR, consistent with sections 69 and 83 of the NGL; and

[194] The term 'market failure' is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

  - AEMO should take the lead on work that is designed to promote the development of, or improve the effectiveness of the operation or administration of, markets, consistent with section 91A of the NGL.
- the depth of knowledge within the gas industry and the important role it can play in helping to develop solutions to some of the issues, either by taking the lead on market developments, or by being closely involved with government, the AEMC or AEMO in the identification of solutions.

We have also been conscious of the fact that there is an existing process for dealing with rule changes and have therefore focused most of our attention on the market design, regulatory design and market development issues.

In terms of assigning a priority to particular issues, we have had regard to the extent to which the issue appears to be affecting the efficient investment in, and efficient operation and use of, natural gas services.

10. Stakeholder Engagement

Stakeholder consultation has been a key element of the scoping study and has been carried out through a variety of forums, including:

- a series of one-on-one meetings, which were held with a number of gas retailers, generators, large end-users, pipeline owners, AEMO, the AER, the ERA, industry associations and various government departments; and
- a gas market scoping study workshop, which was held in Sydney on Friday 31 May 2013 and was attended by key stakeholders and representatives from a number of government departments.

Provision was also made for interested parties to make written submissions.[195]

The issues raised by stakeholders during this consultation process focused primarily upon:

- the manner in which future market developments should be considered;
- the market and regulatory arrangements applying to gas pipelines;
- the design and operation of the DWGM and STTM;
- the regulatory arrangements applying to retailers;
- the level and quality of information available in the market;
- the interaction between the eastern Australian gas market and the NEM; and
- the emergency arrangements.

The remainder of this chapter provides further detail on the specific issues raised by stakeholders. We should caution though that in the time available it has not been possible to validate or otherwise test all of the claims made by stakeholders. The information contained in this chapter is therefore based on what stakeholders have reported and should be treated accordingly.

10.1 Future gas market developments

Throughout the consultation process many stakeholders questioned the value of carrying out a scoping study that only looked at transportation and market arrangements because, in their view, the issues currently facing the market are being driven by upstream developments. In general, stakeholders are of the view that to the extent these issues needed to be considered, they should be looked at as part of a more holistic review that also looks at upstream issues.

Setting this issue aside, one of the more fundamental concerns raised by stakeholders, is that gas market development over the last three years has been fragmented and occurred without any clear strategic direction. Concerns were also raised by a number of stakeholders about:

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[195] Written submissions were received from Alinta Energy, APA, Australian Pipeline Industry Association, Energy Action, the Energy Users Association of Australia, GDF Suez and Origin Energy.

- the lack of industry involvement in the development of some of the more recent initiatives; and
- the potential for reforms to occur when there is no obvious market failure and without due regard to whether the benefits are likely to outweigh the costs, or whether the reform is appropriate given the nature and size of the market.

Of the stakeholders consulted during this process, a number were of the view that no further reforms are required at this time, and that market participants should be given sufficient time to develop, mature and adapt to the changing conditions and take the lead on future developments. Other stakeholders, on the other hand, were of the view that a strategic review, similar in nature to that carried out by Warwick Parer in 2002,[196] should be undertaken and focus on developing a road map for future reform of the upstream, transportation and downstream segments of the eastern Australian gas market.

At this point there is no clear consensus amongst stakeholders as to how the eastern Australian gas market should evolve, or whether a strategic review should be carried out. However, most stakeholders appear to agree that, to the extent any further reforms are required, a more strategic, transparent and measured approach to reform should be employed and industry should be closely consulted throughout the process.

One other observation made by a number of stakeholders is that they would prefer to see a greater degree of institutional separation between the roles of market developer and market operator, when future market developments are being assessed.

10.2 Gas pipelines

The discussions held with stakeholders about the regulatory and market arrangements applying to gas pipelines, touched on a variety of issues, including:

- the Victorian market carriage model;
- the contract carriage model; and
- the effectiveness of the current regulatory framework.

The views expressed by stakeholders on these issues are summarised below.

10.2.1 Victorian market carriage model

The Victorian market carriage model attracted a lot of interest from stakeholders. In general, it would appear that stakeholders accept that the market carriage model has a number of positive attributes. However, they have concerns about the effect that the model and associated regulatory arrangements are having on both:

- *the timeliness and efficiency of investment in the DTS* – while investment in the DTS is occurring, concerns have been raised about:

196 W. Parer, Towards a Truly National and Efficient Energy Market, 20 December 2002.

  - the difficulties of getting expansions underwritten because shippers are unable to obtain exclusive firm access rights under the market carriage model;
  - the manner in which the investment test is applied to proposed expansions of export capacity because benefits arising in other jurisdictions may not be taken into account;
  - the potential for investment opportunities that arise during the regulatory period to be deferred because the owner of the DTS is unable to recover any of the costs associated with such an investment during the regulatory period and is not prepared to take on the risk that the investment will not be approved by the AER; and
  - the potential incentive the owner of the DTS may have to allow congestion to persist because it can derive additional revenue from the auction of higher valued AMDQ credit certificates and storage capacity in the Dandenong LNG facility, both of which currently sit outside the regulatory framework; and
- *the ability of shippers to export gas via the DTS* – while exports via the DTS are occurring, stakeholders have stated that:
  - it has been difficult in the past to obtain AMDQ for exports via Culcairn, which has meant exports have been more susceptible to curtailment than other forms of demand;
  - having to participate in the DWGM represents an additional complexity for those shippers that just want to export gas; and
  - while most of the export debate focuses on exporting gas via Culcairn, there are also a number of impediments to exporting gas from the Gippsland/Bass basins to South Australia via the Port Campbell to Iona (PCI) pipeline, which stems primarily from the manner in which tariffs are calculated on the PCI pipeline.[197]

Given the significance of these issues, it was suggested by one stakeholder that there may be some value in conducting a review of how well regulation, planning, investment and interoperability with other jurisdictions in Victoria is working. Another stakeholder, on the other hand, suggested the market carriage model should be replaced by firm transportation access arrangements with tradable rights. This option was, however, questioned by a number of stakeholders who stated that given the meshed nature of the network, it would be difficult to define capacity meaningfully in order to apply the contract carriage model.

Finally, it is worth noting that a number of retailers noted that while the design of the Victorian market is usually proffered as the reason for the greater number of retailers in Victoria *vis-à-vis* other jurisdictions, the decision to retail in Victoria was more of a function of market size and customer awareness of switching, than market design.

[197] The PCI pipeline does not form part of the DTS.

10.2.2 Contract carriage pipelines

In contrast to the issues raised about the Victorian market carriage model, there is a general perception amongst stakeholders that investment in contract carriage pipelines has been timely and efficient. It also appears to be widely accepted that pipelines will only be built or expanded to the size required[198] to meet committed demand, because of the costs and risks associated with building excess capacity.

The question of whether contract carriage pipelines that are fully contracted are being used efficiently, or whether further trading of capacity by shippers or sales of 'as available' services by pipeline owners could improve the utilisation of these assets, was put to a large number of stakeholders. Their responses are briefly summarised below:

- Shippers that have contracted capacity claim to have a financial incentive to sell any spare capacity because of the sunk cost nature of their investment. This group of shippers also stated that in their experience there has been little demand for this type of service.
- Shippers on the RBP stated it can be difficult to trade capacity on this pipeline because of the technical characteristics of the pipeline (ie, multiple injection/withdrawal points) and the manner in which services are sold (ie, between specific injection and withdrawal points).
- Pipeline owners stated there is nothing to prevent shippers from trading capacity and that some trade already occurs. Pipeline owners also claim to have every incentive to sell contracted but unutilised capacity on an 'as available' basis, because it represents an additional source of revenue.
- A number of small buyers stated that they hadn't experienced any problems negotiating access to transportation capacity with either existing shippers or pipeline owners, while others claimed to have had difficulties accessing specific pipelines.
- The majority of stakeholders agreed that capacity trading and/or sales of 'as available' services was only likely to occur at the margins and for short periods of time because:
  - existing shippers are likely to require their contracted capacity during peak periods and so will only be able to trade their capacity on an 'as available' basis; and
  - the majority of buyers require access to a firm transportation service and can't therefore rely on an 'as available' service.
- A number of stakeholders observed that capacity trading wouldn't resolve the upstream supply issues currently affecting the eastern Australian gas market and also expressed concerns about the potential for heavier handed policy responses to adversely affect investment and impose significant costs on stakeholders for marginal benefit.

With the exception of the RBP most stakeholders are of the opinion that there is no need for regulatory intervention to encourage capacity trading or sales of 'as available' services, some

[198] There is usually a small amount of spare capacity because compressors and looping result in fixed amount of additional capacity becoming available.

have suggested that the search costs for those buyers that are interested in entering into such a transaction could be reduced if:

- the contact details of existing shippers were made available on a web page (eg, as part of the Bulletin Board); and
- information on the availability of spare pipeline capacity was more readily accessible.

It is understood from the submissions that industry and AEMO are already discussing how to progress the first of these initiatives.

One other issue that was raised by some smaller retailers is that pipeline owners may not be interested in offering smaller sized contracts or the flexibility they need to manage variability in demand. This issue was put to a number of transmission pipeline owners and they all responded by stating that there is no minimum size for transportation contracts and they have sought to accommodate the needs of smaller players by offering to supplement a firm service with an 'as available' and/or storage service.

A small number of stakeholders also suggested that in the future there may be some value in operating the existing contract carriage pipelines in eastern Australia on more of a network/market carriage basis, with buyers able to inject and withdraw gas from multiple points. It was acknowledged though that this type of development would probably need to be led by policy makers rather than industry given the contractual rights that already exist on a large number of these pipelines.

10.2.3 Effectiveness of the current regulatory framework

In general, stakeholders appear to be of the view that the NGL and NGR are working effectively and have sufficient flexibility to deal with changing conditions (ie, through the coverage and light regulation provisions). Concerns were, however, raised by a small number of stakeholders about the potential for the different pipeline carriage models and forms of regulation applying to transmission pipelines in eastern Australia to create uncertainty and inefficiencies for those seeking to transport gas between jurisdictions. Some concerns were also raised about:

- the form of regulation to be applied to distribution pipelines; and
- the effect that certain provisions in the NGR may be having on investment.

10.2.3.1 Form of regulation

In a number of the discussions held with pipeline owners, concerns were raised about the tendency for gas pipelines to be regulated in the same manner as electricity, notwithstanding the differences in the rules and conditions in which they operate.[199] Other stakeholders were, however, of the view that it may be appropriate for distribution pipelines to be regulated in this manner because they are a natural monopoly and unlikely to ever be subject to

[199] For example, gas may be subject to competition from electricity.

competition from another network.[200] One stakeholder went on to add that given the difference in the nature of distribution pipelines, it may be appropriate to adopt a higher revocation of coverage threshold for these assets than transmission pipelines.

10.2.3.2 Investment

During the consultation process, a number of pipeline owners noted the potential for the following provisions in the NGR (or the application of these provisions) to affect investment decisions by the owners of regulated pipelines:

- the advance determination on capital expenditure provision (rule 80) – the specific concerns pipeline owners have with this provision relate to the length of time a regulator may take to make a decision under this rule, the level of information a regulator may seek during the process and the inability of the service provider to amend an application during the assessment process;
- the speculative capital expenditure provision (rule 84(2)) – the specific concern pipeline owners have with this provision is that it is unclear whether the rate of return that a regulator would allow to be applied to the speculative capital expenditure account will reflect the risks associated with this type of expenditure; and
- the redundant asset provision (rule 85), which allows any assets that cease to contribute in any way to the delivery of pipeline services to be excluded from the regulated asset base if a mechanism is included in the access arrangement. Before requiring or approving such a mechanism, the AER or the ERA is required to take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users.

Owners of distribution pipelines, the AER and ERA were also asked during the consultation process whether there were any specific impediments to extending these pipelines under the NGR. The common response from all of these stakeholders was that the investment test in rule 79(2) of the NGR does not prevent such extensions occurring and that the decision not to extend pipelines to particular areas simply reflects the fact that it is uneconomic to do so.

Questions were also raised by a number of stakeholders during the consultation process about whether:

- the owners of non-designated regulated pipelines should be able to choose whether or not extensions or expansions of the pipeline should form part of the covered pipeline; or
- these investments should automatically form part of the covered pipeline and therefore be regulated in the same manner as other parts of the pipeline.

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[200] It wasn't clear from the feedback provided by stakeholders whether they had concerns about differences in the specification of the rules in the NGR and NER, or whether their concerns related to the proportion of a pipeline owner's revenue that may be subject to regulatory review.

10.3 DWGM and STTM

The design and operation of both the DWGM and the STTM is another topic that attracted a lot of interest during the consultation process. While some stakeholders questioned the value of these markets, others are of the view that they provide an effective mechanism for trading imbalances. Some stakeholders also claimed that different market designs are making trading more complex for those operating across multiple jurisdictions and giving rise to inefficiencies. Further detail on the views stakeholders have expressed about each of the markets is provided below, along with their suggested improvements.

10.3.1 DWGM

The general view amongst those stakeholders currently participating in the DWGM is that the market provides an effective mechanism for trading imbalances and most were of the view that the movement to *ex-ante* intra-day trading in 2007 has been a positive step forward and something the STTM should try to emulate in the future. Concerns were, however, raised by a number of participants about the complexities and costs associated with operating in this market and the potential for these to act as a barrier to entry into the market.

Concerns were also raised by a large number of participants about the inability of market participants to hedge against all of the risks in the market. That is, while AMDQ provides participants that have an allocation with some[201] protection against congestion uplift charges, they can't be used to hedge against surprise or common uplift charges. Reference was also made in this context to the ASX Victorian Wholesale Gas Futures product, but participants stated this product can only be used to hedge against the *ex-ante* market price and not uplift charges and was not therefore widely used.

One other aspect of the DWGM that was questioned by a number of stakeholders is whether AEMO and the Victorian Government should be the only proponents of DWGM rule changes. This limitation was claimed by many to be unnecessary and in direct contrast to the STTM, where any party can initiate a rule change request. Some stakeholders also noted that it can result in sub-optimal outcomes because AEMO's consultation process tends to be consensus driven and dominated by the larger players.

10.3.2 STTM

The views expressed by stakeholders about the value of the STTM were mixed, with some stating the market provided them with a useful way to manage their imbalances and had enhanced the level of price transparency in the market. Other stakeholders, however, questioned the value of the market and, in doing so, noted that: little trade was actually undertaken through the STTM: the prices were not particularly informative; and there was little evidence to suggest smaller players were able to avoid entering into gas supply and transportation contracts and to rely solely upon the STTM to purchase gas. This group of

201 The term 'some' is used in this context, because an AMDQ allowance will only provide protection up to the AMIQ nominated in the relevant pricing period.

stakeholders went on to state that the STTM has imposed significant costs on participants and pipeline owners, given rise to significant risks that can't be hedged and may be distorting locational decisions and/or deterring entry. It was also claimed that none of the new players in the market were relying solely upon the STTM for gas supplies and that all players in the market had underlying gas supply and transportation contracts.

Although some stakeholders were quite critical of the STTM, there does not appear to be a strong desire to abandon the markets, at least not in Sydney or Adelaide. Rather, it would appear that participants would prefer to address the deficiencies in the current market design. A number of participants did, however, suggest that before any new STTMs are rolled out, they should be subject to a stringent cost benefit assessment.

The most significant concerns raised by participants about the current STTM design relate to:

- the inability of stakeholders to hedge against all of the risks associated with operating in this market because there is not a single daily price that reflects all of the costs payable by participants. Stakeholders have noted that if there was a single daily price then it could pave the way for the development of financial hedging products;
- the MOS arrangements and, in particular: the level of the MOS price cap, which some claim is too high; the prevalence of counteracting MOS in the Adelaide market; the potential for the arrangements to be gamed and the inability of participants to offer MOS on a daily basis; and
- the lack of visibility to participants of their exposure to deviation charges, with this information currently only made available to participants at the end of the month.

In relation to the Brisbane STTM, concerns were raised about the speed with which this market was implemented and the limited time there was to consider whether the bounds of the hub and other design features were appropriate, given the physical characteristics of the RBP and the Allgas and Envestra distribution pipelines. Concerns were also raised about the following features of the Brisbane STTM:

- the STTM is supplied by a single transmission pipeline and has only a small number of participants;
- unlike the Sydney and Adelaide STTMs, a participant in the Brisbane STTM is unable to buy gas from the hub (ie, they cannot just be a user in the STTM), because at least one of the distribution pipelines requires shippers to demonstrate they have title to the gas at the custody transfer point, which implies they must have a transportation contract on the RBP; and
- the STTM design assumes there are no capacity constraints within the hub even though there are some known constraints in the Brisbane STTM and limited interconnection between the networks that make up the hub.

Questions were also raised by a number of stakeholders about whether there would continue to be a need for the Brisbane STTM if the supply hub at Wallumbilla is a success.

10.3.3 Potential areas for improvement

To address some of the perceived shortcomings of both the DWGM and STTM, a number of stakeholders suggested that consideration be given to:

- harmonising certain elements of the DWGM and STTM (such as the start of gas day and market price caps), to reduce the risk of arbitrage across the markets and the costs faced by participants operating in both markets;
- amending the design of the DWGM and STTM so they have a better understanding of their risk exposure on a daily basis and to provide a better platform for the development of financial products that can be used to hedge against all the risks;
- simplifying unnecessarily complex elements of the DWGM or STTM; and
- implementing measures to deal with specific issues in the DWGM or STTM, or conducting a review into these issues.

One stakeholder also suggested that a single imbalance market design should apply across eastern Australia and should be based on the STTM design.

Table 10.1 contains a summary of the specific improvements or areas for review that were identified by stakeholders.

Table 10.1: Suggested improvements to the DWGM and STTM

DWGM and STTM suggested improvements or areas for review
Harmonise the start of the gas day in each market.[202]
Review the methodology used to determine the market price cap and cumulative price threshold in both markets and determine whether the current settings are appropriate given the design of the markets and the interaction of price and risk between the markets.
Pool prudential requirements across the DWGM and STTM and allow subsidiaries to pool prudential requirements.
Develop a single end of day gas price[203] for the STTM that can be used to settle market schedule variations and deviations and can also be used as the basis for developing financial hedging products.
Encourage producers and pipeline owners to participate in the STTM and producers in the DWGM to add further depth to these markets.
DWGM Suggested improvements or areas for review
Introduce a contingency gas mechanism in the DWGM so participants that are able to curtail their load can be compensated for doing so.
Review the methodology used to allocate congestion uplift charges in the DWGM to determine whether it is consistent with the causer pays principle, particularly in those circumstances where the ancillary payments have been incurred as a result of a system constraint or supply source failure and participants without a hedge have been withdrawing gas in line with their schedule.
STTM Suggested improvements or areas for review
Provide STTM participants with a better indication of their deviations on the gas day.
Review the current MOS arrangements in the STTM.
Address the limitations currently prevailing in the Brisbane STTM.
Develop an implementation plan for the introduction of intra-day trading in the STTM.
Address a number of other STTM design issues, such as the treatment of backhaul, cross subsidisation in deviation and market schedule variation charges and the risks posed by third parties submitting incorrect inputs.

202 At least one stakeholder was of the opinion that different start of gas days across the markets was useful because it meant that they could just have one trader work on all markets.

203 The current *ex-ante* price in the STTM does not reflect the effect of market scheduled variations or deviations.

Finally, a number of stakeholders were critical of the time it can take for DWGM and STTM related rule changes to come into effect and have suggested that steps be taken to eliminate any unnecessary duplication of consultation that occurs through AEMO's consultative forums and the AEMC's rule change consultation process.

10.4 Potential trading developments

In a number of the discussions held with stakeholders, reference was made to the Wallumbilla Gas Supply Hub and other potential trading developments. In both cases the reactions from stakeholders were mixed.

The views expressed by stakeholders about the Wallumbilla supply hub are summarised below:

- Some stakeholders are sceptical it will attract sufficient liquidity, given:
  - the lack of physical pipeline interconnection at Wallumbilla and access to transportation capacity on some pipelines in the area; and
  - the continued prevalence of longer term contracts, which they claim means the hub is only likely to be relied upon to purchase small volumes of gas to supplement existing contractual requirements.
- Other stakeholders see the development of the hub as an opportunity, but have noted that the lack of physical pipeline interconnection and access to pipeline capacity is likely to act as an impediment. It has also been noted that other design features, such as the minimum contract size of 1 TJ, may make it difficult for smaller players to participate in this market.

The views expressed by stakeholders about other potential future trading developments, are set out below:

- One stakeholder observed that the market is unlikely to move toward spot and futures trading unless there is a concerted effort to move away from longer term contracts.
- A number of stakeholders stated they would like to see a liquid forward market develop (either through the Wallumbilla supply hub or some other means), but recognise this will be difficult to achieve, particularly given the lack of standardisation across gas supply contracts.
- Some stakeholders stated that they just want to be able to continue to enter into long term gas supply and transportation contracts and do not want to have to deal with any additional complexity in the market.
- One stakeholder noted the potential for a trade facilitation service to be developed that would enable participants to submit bids and offers for supply to a hub for medium and longer term contracts.
- One stakeholder noted that before deciding to implement any more demand or supply hubs in eastern Australia, careful consideration should be given to the costs and benefits

associated with the hub and whether it is the most effective way of delivering its intended purpose. This stakeholder went on to add that liquidity in the eastern Australian gas market is finite and so the establishment of more trading hubs was likely to just result in the liquidity being spread across the hubs. The stakeholder surmised that, to the extent the development of more hubs causes this type of 'fragmentation', it could undermine the efficiency of the price signals.

Finally, it is worth noting that in a number of the discussions held with stakeholders reference was made to the relevance of international markets, such as the Henry Hub in the US and European markets. The one common observation made by stakeholders was that these markets had all taken time to evolve and so it was unlikely that the Australian market would move rapidly away from medium-long term contracts to spot and futures trading.

10.5 Retail markets

In the discussions held with a number of retailers, it was claimed that further efficiencies could be achieved if there was a greater degree of standardisation of:

- the manner in which retailers interface with gas distribution pipelines and, in particular, the information systems used to support business-to-business processes between retailers and distribution pipelines; and
- the terms and conditions of access specified in distribution pipelines' access arrangements and, in particular, the payment terms and indemnity provisions.

A small number of retailers also expressed some concerns about the potential for a significant increase in wholesale gas prices brought about by the LNG developments, to prompt policy makers to try to shield customers from higher prices by imposing a cap on retail gas prices.

10.6 Information

In general, the Bulletin Board was viewed as a favourable development by most stakeholders. A number of stakeholders did, however, suggest the following improvements to deal with perceived gaps in the Bulletin Board and other informational sources:

- Capacity, system adequacy and maintenance information should be made available by designated facility owners for the impending 12 month period, the short term outlook time period should be extended from three to seven days and information on intra-day pipeline flows and linepack should be made available.
- Storage facilities in Queensland that are not currently designated facilities should be designated and required to provide information on both the capacity of the facility and how much gas is stored in the facility.
- To the extent that there are any gas fired generators using unprocessed gas this should be reported and form part of the Bulletin Board.
- A net system load profile should be developed for each demand hub and be readily accessible to stakeholders.

- Information on the costs of transporting gas between various locations in south eastern Australia and Gladstone should be more readily available so that there is a common reference point for the transportation cost component of the LNG netback price at different supply sources (eg, Wallumbilla, Moomba and Longford).

A number of stakeholders also suggested that the quality and accessibility of existing STTM, DWGM and Bulletin Board data should be improved and that compliance with existing requirements should be better enforced.

While a range of improvements have been suggested, some operators of Bulletin Board facilities have stated that the provision of such information is not without cost.

One final issue that was raised by a small number of stakeholders is the proposed gas price index. In short, these stakeholders were sceptical that the index will add anything to the market and stated that because it will be based on the opinion of participants it could be open to manipulation.

10.7 Interaction with the NEM

During the consultation process, stakeholders were asked whether:

1. there was a need for a greater degree of interoperability, risk management and consistency between the eastern Australian gas markets and the NEM;
2. the NEM was having any effect on the facilitated markets or vice versa; and
3. the facilitated markets could affect the locational decisions of new gas fired generation.

The response to the first question was mixed, with some stakeholders questioning the need for any greater degree of convergence between the gas and electricity markets, while those with gas fired generation interests noting that further integration and consistency between the markets could be required in the future. The majority of those with gas fired generation interests were, however, of the view that there was no real urgency to deal with this issue, given the conditions currently prevailing in the NEM and the fact that no new investment in gas fired generation is expected to be required for some time.

On the issue of whether there is a need for a greater degree of consistency between the market parameters used in the NEM, DWGM and STTM, stakeholder views are summarised as follows:

- A number of stakeholders noted the potential for differences in price caps across the NEM and facilitated markets to give rise to arbitrage opportunities and therefore suggested a detailed review be undertaken to determine whether the current market price caps settings are appropriate given the interaction of price and risk between the markets.[204] Other stakeholders questioned the need for any form of alignment between

[204] It was also suggested that when carrying out its periodic reviews, the Reliability Panel should have regard to the relationship between the market parameters in gas and electricity.

market price caps and noted the potential for changes to the facilitated market price caps to expose those that don't have gas fired generation interests to a greater level of risk.

- A number of stakeholders stated that consideration should be given to pooling the prudential requirements of parties operating in both the NEM and the facilitated markets.

On the second question, a number of stakeholders claimed that increased reliance on wind generation in South Australia and, to a lesser extent, Victoria was affecting the operation of the facilitated markets, because when the wind drops off, gas that would otherwise have been supplied to the facilitated markets is being rapidly diverted to gas fired peaking generation.

The responses to the final question were mixed, with some stakeholders claiming that the complexities associated with operating within the facilitated markets may distort the locational decisions made by new gas fired generators (and other new large end-users). Others, however, pointed to new entry within the DWGM as evidence that the facilitated markets have little effect on investment decisions. Those stakeholders with gas fired generation interests stated that the locational decision will depend more on the proximity of the location to a fuel source and electricity transmission capacity than the location of the facilitated markets.

10.8 Emergency arrangements

The arrangements that been put in place to deal with emergencies affecting more than one jurisdiction is the final topic that attracted the interest of a small number of stakeholders. While most were of the view that AEMO and industry have the right level of involvement in emergencies through the NGERAC, some noted the need for:

- AEMO to play more of a central coordination role during emergencies;
- greater transparency around the curtailment principles to be employed by jurisdictions in an emergency; and
- a more comprehensive set of information than is currently available on the Bulletin Board to be made available during emergencies, so that they can be effectively managed.

11. Findings of the Scoping Study

As the discussion in the preceding chapter highlights, there are some perceived deficiencies with the existing regulatory and market arrangements and the manner in which policy and market development has occurred over the last two to three years. Based on our own high level review of these arrangements, we agree that some aspects of the current arrangements may be adversely affecting the productive, allocative and/or dynamic efficiency of the provision of natural gas services. Other general observations we would make are that:

- the changes currently underway in the market (see chapter 4) could test some of these arrangements in the future;
- any future market development work carried out by policy makers, the AEMC or AEMO should be guided by the NGO and subject to a rigorous and transparent assessment process, with industry consulted effectively throughout the process; and
- there is a clear need for a strategic review to be carried out to determine just how the eastern Australian gas market can make the transition from its current, relatively immature state, to a more mature, well-functioning market (comprising commodity, transportation and financial markets) that supports:
  - the efficient allocation of gas and transportation capacity in the short, medium and long term;
  - the efficient trade and movement of gas between jurisdictions;
  - efficient and timely investment in upstream production and transportation capacity; and
  - the efficient allocation of risks between market participants and allows participants to hedge risks.

These three issues are explored in sections 11.1-11.3 of this chapter, while sections 11.4 - 11.10 set out the results of our assessment of:

- whether there are any particular issues with the current regulatory and market arrangements that may benefit from a more detailed review (Step 1);
- the likely materiality of these issues (Step 2); and
- the options for progressing those issues found to be material and who would be best placed to take the lead on the issue and/or undertake any detailed work (Step 3).

It is important to reiterate that the relatively short period for completing this scoping study has only allowed a very high level review of the issues. The findings contained in this chapter should therefore be viewed accordingly.

11.1 Influence of changes on existing arrangements

To better understand the potential effect of changes currently underway in the eastern Australian gas market on the existing regulatory and market arrangements, we have considered how the following changes could affect the movement and trade of gas:

- Conditions in the market continue to tighten in the short to medium term as the LNG projects ramp up and a large number of domestic gas supply contracts expire, with the effects of this tightness being felt most acutely in Queensland (see section 4.4).
- Gas prices across eastern Australia converge toward the LNG netback level (with prices either linked to an international oil price benchmark or set at an equivalent level) as existing contracts roll off and new contracts are entered into (see section 4.4.2).
- New sources of supply need to be developed in the medium to long term to fill the void created by the LNG developments but in the interim more gas from Victoria is supplied into NSW, the ACT, South Australia and, potentially Queensland (see section 4.4).
- The demand for gas by generators falls and no new investment in gas fired generation occurs in the short to medium term unless conditions in the NEM change materially, or there is a change in climate change policy settings that supports such generation (see section 4.3).

Some of the ways in which these changes *may* affect the movement or trade of gas in eastern Australia in the short to medium term are outlined in Box 11.1. The term ‘may’ is used in this context because it is not possible to determine precisely how all of these changes will affect the market. The material in this box should therefore be viewed as illustrative only.

Box 11.1: How changes *may* affect the movement or trade of gas in short to medium term

Tighter conditions in Queensland – as existing gas supply contracts expire, it may become difficult for large buyers in Queensland to find producers in the area that are willing to enter into a medium to long term contract until the LNG facilities ramp up (2015-2018). Large buyers in Queensland may therefore need to either rely on shorter term contracts or gas from Victoria in this period. If gas is purchased from Victoria, then buyers may either:

- enter into a swap with a party that has gas in Queensland but needs gas in south eastern Australia, which could result in a reduction in the utilisation of pipelines previously used to bring gas south from Queensland; or
- have the gas transported from Victoria via the eastern (via the EGP), central (via the DTS) or western (via the SEA Gas Pipeline) routes. If gas is transported via the central route, the buyer will have to participate in the DWGM and deal with differences between the market and contract carriage models. If, on the other hand, gas is transported via the eastern or western routes, the buyer will have to participate in the STTM. Depending on the predominant flow of gas on some pipelines, the buyer may also have to rely on a less than firm transportation arrangement, because backhaul tends to be provided on an 'as available' basis.

Higher gas prices - if wholesale gas prices rise to the LNG netback level, the following could occur:

- Policy makers could try to protect small customers from the increase by imposing a cap on retail prices.
- Higher prices could prompt a significant reduction in demand by domestic customers, which could, in turn, result in a reduction in the utilisation of pipelines and some parts of the pipelines being deemed redundant.
- If the prices paid by retailers become linked to international oil prices they will have to find new ways of hedging their exposure. In those jurisdictions where retail price regulation is in place (NSW only at this time), this will add further complexity to determining an appropriate retail price cap.

Greater reliance on Victorian supplies in south eastern Australia – if there is a significant reduction in gas supplied from the Cooper and Bowen/Surat basins into NSW/ACT and South Australia, and more gas has to be supplied to these jurisdictions from Victoria until new sources are developed, the following could occur:

- There could be a significant reduction in the utilisation of the MAPS and MSP (or part thereof) while the utilisation of the SEA Gas Pipeline, EGP and/or the DTS/Interconnect/MSP (between Culcairn and Sydney) could increase.
- If more gas is exported via the DTS, buyers would need to participate in the DWGM and deal with differences between the market and contract carriage models.
- The increased reliance placed on gas from Victoria until new sources of supply are brought on line could result in these jurisdictions becoming more exposed to any emergencies that may arise in this state (ie, because there is less diversity of supply).

New sources of supply – if the Gunnedah and Gloucester basins are developed and used to supply NSW, then new pipelines will need to be built. The development of these new sources of supply could result in a material reduction in the utilisation of the EGP and the MSP (or part thereof if gas from Gunnedah is supplied via the CRP and CWP).

Increased reliance on Cooper and Bowen/Surat basin gas for LNG projects – if significant volumes of gas from the Cooper Basin are used for the LNG projects and less gas from the Bowen/Surat basins flows south, it could result in the predominant flow and utilisation of the SWQP/QSN changing. It may also mean that if there is an emergency in either basin and rationing is required, consideration will need to be given to how to share gas between exports and domestic customers.

Implications of conditions in the NEM – the forecast subdued growth in demand for electricity and continued expansion of renewable energy sources in South Australia and, to a lesser extent, Victoria, could result in gas fired generators playing more of a back-up role, which could lead to:

- a greater degree of volatility (price and quantity) in the Adelaide STTM and DWGM and therefore expose participants in these market to a greater degree of risk; and
- a reduction in the utilisation of pipelines servicing gas fired generators, which may result in certain parts of these pipelines becoming redundant for a period of time.

If, on the other hand, demand for gas from the NEM increases, there could be greater interaction between gas and electricity markets.

* Note the material in this box should be considered illustrative only.

In short, the material in this box suggests that, in the short to medium term, the changes underway in the market *may*:

- test the degree of interoperability between the Victorian market carriage and contract carriage models, given the potential for more gas to be exported from Victoria to other markets in south eastern Australia;
- have a material effect on the utilisation of some pipelines, which could:
  - result in the capacity of those pipelines experiencing a substantial reduction in utilisation becoming partially redundant; or
  - mean significant investment is required on pipelines experiencing higher utilisation.

  These effects could be transitory or permanent and so to the extent the effects are felt by regulated pipelines, regulators will need to consider carefully how to use particular rules in the NGR, such as the new facilities investment and redundant asset provisions;
- result in a greater degree of volatility in the Adelaide STTM and, to a lesser extent the DWGM, given the amount of new renewable generation forecast in these locations and the increased reliance that may be placed on gas fired generation to act as back-up generation;
- adversely affect retail competition if policy makers respond to higher gas prices by imposing a cap on retail prices that doesn't allow efficient costs to be recovered; and/or
- test the emergency arrangements in the future, given the potential for:
  - south eastern Australian to be more exposed to emergencies that may originate in Victoria, due to greater reliance on gas from Victoria until new sources of supply are brought on line (ie, because there is less diversity of supply); and
  - emergencies affecting the supply of gas from the Cooper or Bowen/Surat basins requiring gas to be apportioned between export and domestic customers.

These potential short to medium term effects are explored in further detail in sections 11.4-11.10.

Over the longer term, the market will continue to evolve and be subject to a range of different pressures, which could further test the regulatory and market arrangements. More proactive monitoring may therefore be advisable in the future to identify emerging issues earlier, and if necessary take action to ensure the arrangements remain fit for purpose.

11.2 Assessment of future regulatory or market interventions

One of the more fundamental concerns raised by stakeholders is that policy and market development over the last two to three years has been occurring in a less than rigorous manner, with limited consideration purportedly given to:

- the extent to which there is a market failure that warrants regulatory intervention;
- whether the regulatory response is:

  - fit for purpose given the characteristics of the market;
  - targeted and proportionate to the issue it is intended to address; and
  - consistent with the principles established by the NGO; and
- the importance of undertaking transparent consultation and a robust cost benefit assessment.

Irrespective of whether or not this is an accurate characterisation of what has occurred, it is a timely reminder for those involved in policy and market development to ensure that future regulatory or market interventions are assessed in a transparent and open manner having regard to both the NGO and COAG's Principles of Best Practice Regulation. That is:

- The market failure[205] or deficiencies in the existing legislative/regulatory framework should be clearly articulated before any steps are taken to try to identify a solution.
- Once articulated, the set of feasible policy solutions (including regulatory, self-regulatory, co-regulatory and non-regulatory approaches) should be identified, having regard to:
  - the NGO and any other principles identified by SCER;
  - the nature and size of the market, the physical characteristics of the market (ie, pipeline characteristics and nature of demand) and the commercial arrangements underpinning the supply and transportation of gas;
  - whether the solutions are targeted and proportionate to the issue they are intended to address; and
  - input from stakeholders.
- The set of feasible solutions should then be assessed by carrying out a transparent cost benefit assessment and a regulatory solution should only be implemented if it yields the greatest net benefit and is consistent with the NGO.
- Industry, end-users and other key stakeholders should be consulted effectively throughout the process and involved in both the articulation of the problem and the identification of the set of feasible solutions.

The importance of the last of these points cannot, in our view, be underestimated, given the depth of knowledge that exists within the gas industry.

In practice, as with any regulatory or decision making process, promoting good outcomes needs to strike the right balance between sometimes conflicting considerations – for example the need to make time decisions versus the robustness of analysis able to be undertaken; and the need to make judgements in the face of incomplete information.

205 The term 'market failure' is used in this context to refer to a situation in which the market, left to its own devices, is unable to allocate resources efficiently.

11.3 Strategic review of gas market development

A common theme emerging from many of our discussions with stakeholders is that gas market development in eastern Australia over the last two to three years has occurred in a relatively ad-hoc manner and without a clear strategic direction of how the market can make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports:

- the efficient allocation of gas and transportation capacity in the short, medium and long term;
- the efficient trade and movement of gas between jurisdictions;
- efficient and timely investment in upstream production and transportation capacity; and
- the efficient allocation of risks between market participants and allows participants to hedge risks.

In our view, this constitutes a real gap in the market and, if not addressed, could result in the implementation of sub-optimal market development decisions that:

- risk undermining confidence in the market; and
- may result in a reduction in the productive, allocative and/or dynamic efficiency of the eastern Australian gas market and other downstream markets, and, in so doing, adversely affect the long term interest of consumers.

Consistent with SCER's policy principle of 'promoting market development', we would therefore recommend that steps be taken to fill this gap over the next 12-18 months through a strategic review that considers both:

1. the direction that facilitated markets in eastern Australia should take over the next ten to fifteen years if the market is to make the transition to a more mature and well-functioning market that exhibits the characteristics set out above. Some of the matters we think would be relevant to consider in this context include:
   - what the market can be expected to look like if it evolves in this manner;
   - the likely optimal structure and location of facilitated markets, given the characteristics of the market and the need to attract depth and liquidity;[206,207]
   - the pre-conditions for the market to evolve in this manner, how long it is likely to take and any intermediary steps the market is likely to have to take;

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206 Some of the characteristics that will be important to consider in this context are: the small number of players in the market, the geographic dispersion of players, the difference in the nature of demand across locations, the potential for medium to long term contracts to continue to have a role in the market over the longer run and the level of liquidity in the market. One other point to bear in mind is that a one size fits all approach may not be appropriate given differences in physical and regulatory arrangements prevailing in each jurisdiction.

207 As a general observation, given the size and nature of the market, it is unlikely that the eastern Australian gas market could support more than one upstream supply hub that acts as a reference point for wholesale gas prices because, as one stakeholder pointed out, there is only a finite amount of liquidity in the market and dividing this across multiple supply hubs could undermine the efficiency of the price signal. See Origin, Submission to Gas Market Scoping Study, 14 June 2013, p.2.

- whether the market, if left to its own devices, will evolve in this manner, or whether some form of policy intervention might be required to support the development;
- the relevance of the experience garnered in other international markets;
- how a well-functioning financial market can be developed; and
- whether the existing facilitated markets (eg, the DWGM and STTM) are meeting their stated objectives in the most efficient manner and if the development of any new facilitated markets may obviate the need for any of the existing facilitated markets.

2. the principles that should guide the development of facilitated markets in the future. Some of the matters we think would be relevant to consider in this context include:
   - the circumstances in which it will be appropriate to employ particular types of facilitated markets and the importance of having regard to market characteristics;
   - how a market should be designed, so as to minimise costs and risk exposure, and to provide an appropriate basis for the development of financial hedging products; and
   - the assessment framework to be used when deciding to implement a new market.

In keeping with the allocation of functions and responsibilities set out in the NGL, we are of the opinion that:

- the review should be sponsored by SCER; and
- consistent with its market development function under the NGL, the AEMC should be accorded responsibility for actually carrying out the review.

In keeping with its standard practice, we would expect the AEMC to carry out such a review in close consultation with industry and other key stakeholders, such as AEMO and the AER.

11.4 DWGM and STTM

Three issues that have become clear from our review of the STTM and DWGM and the consultation process are that:

- certain design elements of the STTM and DWGM appear to be imposing unnecessary costs on market participants and exposing them to risks that cannot be effectively hedged;
- the time taken to develop, review and implement STTM and DWGM related rule changes has been protracted and may be imposing unnecessary costs on market participants; and
- the restriction on who can propose DWGM related rule change may need to be reviewed.

Each of these issues is examined, in turn, in the remainder of this section.

11.4.1 Improving the design of particular elements of the DWGM and STTM

Based on our high level review of the DWGM and STTM, it appears that while the imbalance components of these markets are working relatively effectively, some of the ancillary components,[208] may be imposing costs on participants (and, in turn, consumers) and giving rise to risks that cannot be effectively hedged.[209]

Some other general observations we would make about these markets are that:

- Inconsistencies between the risk management frameworks adopted in both the DWGM and STTM (eg, the market price cap, the cumulative price threshold and prudential requirement arrangements) and differences between other market design elements (eg, start of gas day) may be imposing unnecessary costs on market participants operating across the two types of markets.
- Certain elements of both the STTM and DWGM are complex, which in addition to imposing costs on market participants, may be deterring entry into these markets.
- There appear to be some specific design issues in the Brisbane STTM, which may be affecting the efficacy of this market (see section 10.3.2).
- The continued expansion of renewable generation could result in a greater degree of volatility in the Adelaide STTM and the DWGM and, in so doing, expose participants in these markets to a greater degree of risk (see section 11.1).

While we are not in a position to quantify the extent to which these issues are affecting the efficient trade of gas or imposing unnecessary costs and risks on market participants (and, in turn, consumers), stakeholder feedback suggests they are having a material effect and that the effects are being felt more acutely in the STTM. We are therefore of the view that there is a case for carrying out a more detailed review of the design of the STTM to determine whether the existing design can be improved. Given that it has been over nine years since the last detailed review of the DWGM was carried out,[210] we think there may also be value in carrying out a review of particular elements of this market design, in conjunction with the review of the STTM.

Indicatively, such a review could focus on opportunities for:

- removing any inefficient or unnecessary costs – matters that may be relevant to consider in this context are whether:
  - any unnecessarily complex elements of the markets can be simplified;

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[208] For example, the ancillary payment/uplift component of the DWGM and the MOS/deviation component of the STTM.

[209] As noted in Box 11.1 it is possible that this risk exposure could become greater in the future if, as a result of the continued expansion of the renewable energy, gas fired generation demand becomes more variable and deviations in the STTM or DWGM become more significant.

[210] VENCorp, Victorian Gas Market Pricing and Balancing Review – Recommendations to Government, 30 June 2004, p.11.

- the prudential requirements of participants (and their subsidiaries) operating across the DWGM and STTM could be pooled;
- there would be any benefit in harmonising the start of gas day across the markets; and
- the level of the MOS cap in the STTM is appropriate, given the function it plays in the market and the investment signals it is intended to provide.

▪ improving the ability of participants to manage risks by:
  - ensuring the design of the markets can support the development of financial products that can be used by participants to effectively and efficiently hedge risks; and
  - providing participants in the STTM with the information they require to understand their daily risk exposure.

▪ developing a consistent risk management framework across the DWGM and STTM, having regard to:
  - the differences between the design of these two markets;[211] and
  - the effect any changes to the market price cap or the cumulative price threshold may have on the risk that participants in the two markets are exposed to.[212]

▪ addressing the Brisbane STTM design issues (see section 10.3.2);

▪ addressing other specific design issues raised by stakeholders (see Table 10.1); and

▪ intra-day trading for the STTM, having regard to the nature and size of the STTMs, the types of users in these markets and the additional costs and complexities this would add. If the benefits of moving to intra-day trade are judged to exceed the costs, an intra-day implementation plan should be developed.

Ideally such a review would follow the strategic review outlined in the preceding section, because one of the issues the strategic review will look at is the effectiveness of the existing facilitated markets. To ensure the scope of this review does not become too broad, and that the level of effort is proportionate to the underlying issues, we would suggest that SCER and the AEMC work together to prepare draft terms of reference at the completion of the strategic review. At this stage it is difficult to determine precisely what the scope of the review will be and whether the AEMC and/or AEMO should be responsible for carrying out such a review. We would therefore suggest this be considered by SCER when preparing the draft terms of reference, having regard to the functions of both organisations as set out in sections 69 and 91A of the NGL. In principle, the AEMC should be responsible for defining the high level design of these markets, while AEMO should be responsible for carrying out the detailed design and implementation work.

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211 The different design elements include intra-day vs day ahead trading, the number of players and access to storage.

212 One thing to bear in mind is that while eliminating arbitrage opportunities across the two markets may be considered important, changes to the market price cap can expose participants to significant risks. Careful consideration must therefore be given to whether the benefits of eliminating the potential for arbitrage to occur are likely to exceed the costs and risks imposed on market participants.

Such a review should be carried out in close consultation with industry and other key stakeholders, including the AER. The need to consider how some of the risks in these markets could be hedged through financial products suggests possible value in involving people with experience in developing derivative products.

11.4.2 Rule change process

Another issue that we think needs to be considered further by both the AEMC and AEMO, is how the time taken to develop and/or review STTM and DWGM related rule changes can be shortened. This issue was raised by nearly all of the stakeholders we spoke to and in each case the stakeholders asserted there was a significant degree of duplication in the consultation process carried out by both AEMO and the AEMC.

Apart from imposing additional consultation costs on participants, the duplication of consultation processes has the potential to substantially delay the implementation of rule changes that are required to address significant issues with the existing rules and, in so doing, impose additional costs and/or risks on market participants.

Given the potential inefficiencies associated with the current arrangements, we would suggest that AEMO and the AEMC work together over the next six months to determine how the consultation process can be streamlined, taking into account their respective consultation obligations under the NGL and NGR. To the extent that provisions in the NGL and NGR are acting as an impediment to such streamlining, this issue may need to be escalated to SCER.

11.4.3 Restriction on DWGM related rule changes

Section 295(3)(a) of the NGL currently prevents anyone other than AEMO or the Victorian Minister for Energy and Resources from submitting a DWGM related rule change request to the AEMC. While we can see that this limitation may have been introduced originally to ensure that there was some degree of co-ordination of DWGM related rule changes by the market operator, stakeholders have claimed that:

- it is unduly restrictive and may be resulting in sub-optimal outcomes; and
- the restriction is at odds with STTM rule changes, which can be submitted by any person.

Although we are not in a position to test the first of these claims, we do think there would be value in the Victorian Department of State Development, Business and Innovation (DSDBI) considering whether there is still a rationale for imposing this restriction and if so, whether any improvements could be made to the current process. We would therefore recommend the AEMC advise the Victorian DSDBI of the feedback received from stakeholders and allow it to determine how to proceed.

11.5 Pipeline carriage models

One of the more elementary questions arising during the scoping study is whether the contract carriage and Victorian market carriage models are promoting efficient investment in, and efficient use of, transmission pipelines. Before setting out the results of our high level assessment of this question, it is worth taking the time to explain the efficiency trade-offs that exist between these models.

11.5.1 Efficiency trade-offs

From an economic efficiency perspective, the Victorian market carriage model appears to promote both:

- the efficient use of the DTS because:
  - the gas spot price facilitates access to the DTS by those who value access most highly; and
  - use of the pipeline is unencumbered by contract capacity rights, which avoids problems associated with capacity trading, including difficulties in defining capacity and the potential exercise of market power by incumbent shippers or the pipeline owner.
- dynamic efficiency in other markets, such as the upstream market (though improved access to the pipeline system by new producers) and the retail market (by reducing the barriers to entry for new retailers).

The inability of shippers operating within a market carriage model to secure firm access rights may, however, mean there is less assurance of efficient and timely market-based investment in the pipeline because shippers are unwilling to fund any expansions they cannot guarantee having firm access to, even if the benefits of doing so outweigh the investment cost. Instead, investment decisions need to be made through a regulatory process, which some may consider less efficient and timely than relying on market driven investment incentives.

The contract carriage model, on the other hand, arguably should encourage efficient investment in the pipeline, because shippers can secure firm access rights to any capacity expansions they fund, and are in a better position to manage long term investment risk through commercial arrangements with gas producers and/or end-users. Shippers should only be willing to fund investment in the pipeline if the benefits of doing so outweigh the cost of the investment, which promotes both allocative and productive efficiency.

Whether or not a contract carriage pipeline will be utilised in the most efficient manner will depend on:

i. the extent to which firm capacity rights can be defined efficiently, which, in turn, depends on the physical characteristics of the pipeline, ie, whether the pipeline is a simple point-to-point pipeline, a point-to-point pipeline with multiple injection/withdrawal points or a meshed network. Of these three options, the simple point–to-point pipeline is the easiest one on which to define firm capacity rights;[213]

ii. whether the shipper and/or pipeline owner has the appropriate incentives and ability to on-sell any spare capacity (see section 5.4);

iii. whether a prospective shipper can rely on the type of service being sold by the shipper and/or pipeline owner (ie, if the prospective shipper is only able to secure an 'as available' service but it requires a firm transportation service then this may not be sufficient) (see section 5.4); and

iv. the transaction and co-ordination costs associated with entering into such a trade.

It follows from the preceding discussion that the choice between market and contract carriage models may involve a trade-off between promoting:

- efficient investment in the pipeline (contract carriage); and
- efficient utilisation of the existing pipeline and dynamic efficiency in upstream and downstream markets (market carriage).

At different points in time these trade-offs may become more or less important. For example, when a market carriage pipeline needs to be expanded, the unwillingness of shippers to underwrite the investment brings this shortcoming of the model clearly into focus. At other times, however, the effects of this shortcoming may be less acute. Similarly, when a contract carriage pipeline is fully contracted and consideration is given to expanding the pipeline even though there is spare unutilised capacity, it highlights the potential for pipeline utilisation to be inefficient. At other times, however, the effects of this shortcoming may be less acute.

In our opinion, these efficiency trade-offs are important to bear in mind when considering whether or not to move from one type of carriage model to another. The remainder of this section sets out the results of our high level review into whether the Victorian market carriage and the contract carriage models have been encouraging efficient investment in, and use of, gas pipelines.

11.5.2 Victorian market carriage model

The Victorian market carriage model has a number of positive attributes, including open access, relatively low barriers to entry and exit for market participants. It also appears to promote efficient utilisation of the DTS and dynamic efficiency in both upstream and downstream markets. Concerns have, however, been raised by stakeholders about the timeliness and efficiency of investment in the DTS and, to a lesser extent, the ability to export gas via the DTS.

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213 In a meshed network it can be difficult to define firm capacity rights in a meaningful or efficient manner because the capacity in a particular location can depend on what others are doing in other parts of the network. Similar issues may also arise on point-to-point pipelines with multiple injection/withdrawal points because the capacity in a particular part of the pipeline will depend on what is being injected or withdrawn from another part of the pipeline.

Although we understand that a significant amount of investment (including export capacity related investment) has recently been approved by the AER in the 2013-2017 DTS access arrangement review process[214] and that exports via the DTS are increasing,[215] the issues raised by stakeholders are, in our view, still worth exploring. Our observations on the specific issues raised by stakeholders and recommendations are set out below.

11.5.2.1 Observations on issues raised by stakeholders

One of the more substantive issues stakeholders raised about investment in the DTS is that shippers have little incentive to underwrite investment in the DTS because they are unable to obtain firm access rights and so investment decisions depend upon the regulatory process, which may result in less than timely or efficient investment. In addition to this issue, concerns have been raised by stakeholders about:

- the potential for investment opportunities arising during the regulatory period to be deferred because of certain features of the regulatory framework;
- the potential incentive the owner of the DTS may have to allow congestion to persist;
- the manner in which the investment test is applied to export projects; and
- the ability to export gas via the DTS.

These issues are explored below.

Timeliness of investment

Based on our understanding of what has occurred in Victoria over the last five years, reliance on regulatory processes for investment decisions appears to have led to at least one less than optimal outcome. That is, the proposed expansion of the South West Pipeline (SWP), which was deferred from the latter part of the 2008-2012 regulatory period to the 2013-2017 regulatory period.

This proposed expansion was rejected by the ACCC in the 2008-2012 DTS access arrangement review on the grounds there was too much uncertainty surrounding the time at which the option would be required and the appropriateness of the proposed solution.[216] While the proposal was rejected, the ACCC noted that if conditions changed during the period, the owner of the DTS could seek a binding approval from the regulator at any time during the access arrangement period.[217] Although this option was open to the DTS owner,

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214 In its final decision the AER approved $171.5 million in capital expenditure, of which $83.2 million is to be spent on the Gas to Culcairn project, which will result in the expansion of export capacity at Culcairn. See AER, Access arrangement final decision – APA GasNet Australia (Operations) Pty Ltd 2013-17, Part 1, March 2013, pp. 20-23.

215 According to actual flow data from the Bulletin Board, exports from Culcairn in 2012 were around 11.2 PJ while in 2011 they were around 8.7 PJ.

216 ACCC, Final Decision: GasNet Australia – revised access arrangement, 2008-2012, 30 April 2008, pp. 46-47.

217 ibid, p.47.

the option was not exercised within the period and it would appear the expansion is now to occur in 2013-14 as part of the Gas to Culcairn project.[218]

The effect of this deferral is not easy to quantify, but public submissions on this deferral suggest it may have contributed to: [219]

- congestion on the SWP;
- higher spot prices; and
- shortages of AMDQ credit certificates on the SWP, which have the potential to expose some users to congestion uplift charges.

Apart from affecting the productive efficiency of the DTS, these submissions suggest that the delay may have also imposed costs and risks on market participants and, in turn, consumers.

While this is the only significant example we have been able to identify over the last five years, we still think there would be merit in exploring this issue further, particularly given the potential for the delays in efficient investment to adversely affect market participants and the efficiency of the pipeline. Our specific recommendations are set out in section 11.5.2.2.

Intra-period investment opportunities

During the consultation process it was claimed that investment opportunities arising within the regulatory period tend to be deferred until the commencement of the next period, because:

i. the investment costs can't be recovered from shippers through the approved tariffs during the regulatory period; and

ii. the owner won't take on the risk that the AER will not approve the investment.

Given that there are a number of provisions in the NGR that are designed to enable investment to occur within the regulatory period, this claim was somewhat surprising. For example, rule 80 of the NGR allows the service provider to seek an advance determination from the AER on proposed capital expenditure within the regulatory period. While this option wouldn't necessarily address the first point set out above, it would ameliorate the risk of the investment not being approved.[220] If the first point is a significant barrier to intra-period investment, then the service provider could also include a trigger event in the access arrangement to deal with any significant investments required within the period. Alternatively, the service provider could submit a proposal to the AER seeking a variation of its access arrangement during the regulatory period (rule 65).[221]

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218 AER, Draft decision - Access arrangement, APA GasNet Australia (Operations) Pty Ltd 2013-17, Part 2, September 2012, p.49.

219 See for example, EnergyAustralia Gas Storage, Submission - APA GasNet Access Arrangement 2013-2017, 7 January 2013 and APA, Submission to the AEMC's Reference and Rebatable Services review, 5 October 2012.

220 We understand that this option was used by the owner of the DTS in 2006 to have the Brooklyn Lara Pipeline approved. See AER website (http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements).

221 We understand that this option was used by the owner of the DTS in 2004 and 2008 to deal with a number of proposed variations. See AER website (http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements).

Stakeholders did not explain why these options are not currently being employed, but it could reflect a range of different things, such as:

- deficiencies in the current drafting of the rules;
- the AER's application of the rules;
- the costs associated with pursuing these options; and/or
- the limited incentive the service provider may have to pursue such options.

In our view, this is an issue that warrants closer consideration, particularly given the potential for the deferral of efficient investments to adversely affect market participants and the efficiency of the pipeline. Our recommendations on how such a review could be carried out are set out in section 11.5.2.2.

Incentive to allow congestion to persist

One other concern raised by some stakeholders is that the owner of the DTS may have an incentive to allow congestion to persist because it can derive additional revenue from the auction of higher valued AMDQ credit certificates and storage capacity in the Dandenong LNG facility, both of which currently sit outside the regulatory framework. While we can see that, in principle, the auction arrangements and ownership of the LNG facility may give rise to such an incentive, it is not clear from any of the material we have reviewed that the owner of the DTS has acted on this incentive. That is not to say it may not act on the incentive in the future, but with significant investments about to be undertaken in the DTS, this is unlikely to be an issue over the next access arrangement period. Having said that, this is an issue we think would be worth exploring further as part of a broader review (see section 11.5.2.2).

Application of the investment test to export projects

Another concern raised by some stakeholders is that when applying the investment test to export-related projects, the AER may not take into account benefits arising in other jurisdictions. Based on our review of regulatory decisions that have involved export related investments, it would appear that while this may have been an issue under Gas Code,[222] it is no longer an issue under the new investment test set out in rule 79 of the NGR.

Specifically, it would appear from our review of the AER's most recent export oriented investment decision (the Gas to Culcairn project), that when considering the proposed investment, the AER took into account the economic benefit that would be derived by a range of parties (eg, the owner of the DTS, users of the DTS, end-users and gas producers),[223] but had no regard to the location of those beneficiaries.[224]

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222 See for example, ACCC, Final Decision – GasNet Australia – revised access arrangement, 2008-2012, pp. 41-42

223 This project was assessed under the first limb of the investment test, ie, capital expenditure is justifiable if the overall economic value of the expenditure is positive.

224 AER, Access arrangement final decision – APA GasNet Australia (Operations) Pty Ltd 2013-17, Part 1, March 2013, Attachments, p.40.

The only point at which the AER appeared to consider the location of the beneficiaries was when it was deciding how to allocate the costs of the approved investment between different users and to structure the Culcairn export tariff.[225] The fact that some of the beneficiaries were located outside Victoria did not therefore appear to have any bearing on the AER's assessment of whether or not to approve the investment.

On the basis of our high level review, there does not appear to be anything fundamentally wrong with either the drafting of rule 79 of the NGR or the AER's application of this rule to export projects. We are not therefore recommending any further work to be carried out on this issue.

Export related issues

One of the primary concerns raised by stakeholders that have sought to export gas via the DTS is that, in the past, it has been difficult to obtain AMDQ for exports via Culcairn, which has meant exports have been more at risk of curtailment than other forms of demand. Based on our review, it would appear that while this has been an issue in the past, it has been addressed through both the assignment of AMDQ to Culcairn and capacity expansions. That is not to say it may not become an issue again in the future. We would therefore recommend further consideration be given to this issue as part of a broader review (section 11.5.2.2).

Another concern raised by stakeholders is that having to participate in the DWGM represents an additional complexity for those shippers that just want to export gas via the DTS. While we recognise this may be viewed as an impediment to exports, it is worth noting that shippers seeking to export gas to NSW can bypass the DWGM by exporting gas from the Gippsland Basin via the EGP while shippers seeking to export gas to Adelaide can export gas from the Otway Basin via the SEA Gas Pipeline. For those shippers seeking to export gas to Queensland, however, there does not appear to be any way to bypass the facilitated markets (eg, if gas is exported via the EGP (SEA Gas Pipeline) the shipper would need to participate in the Sydney (Adelaide) STTM or if gas is exported via the Interconnect the shipper would need to participate in the DWGM) unless the shipper is prepared to fund the development of a new lateral that would bypass the STTMs. It has not been possible to determine how significant an issue this is at present but it is something that we think should be considered further during the strategic review (see section 11.3).

Two other issues arising from our consideration of the effect the changes underway in the market may have on the movement of gas, are that:

- More gas may need to be exported from Victoria to the remainder of south eastern Australia and potentially, Queensland, until new sources of supply are developed and/or the LNG facilities ramp up. While this may be a transitory issue, we are of the view that the regulatory arrangements should be flexible enough to deal with this change and not act as an impediment to this occurring. This is an area that we think should be considered more closely (see section 11.5.2.2).

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[225] ibid.

- Increased exports may test the degree of interoperability between the Victorian market carriage and contract carriage models. The potential for the different carriage models to act as an impediment to exports was raised with a number of stakeholders that are either currently exporting gas from Victoria or are considering doing so, but none of the stakeholders we spoke to considered this to be a significant issue. We are not therefore recommending any further work be carried out on this issue.

11.5.2.2 Recommendations

As the preceding discussion highlights, a number of factors have contributed to the investment and export issues observed in Victoria over the last five years. The root cause of most of the issues can, however, be traced back to the fact that market participants are unable to obtain exclusive firm capacity rights on the pipeline under the existing model and so investment decisions are based on regulatory processes, which may not be optimal.

In our opinion, there are two potential options that could be taken to promote improved investment outcomes in the DTS, which differ depending on whether the investment issues are viewed as a deficiency in the current regulatory process or market design. These options are not necessarily mutually exclusive, but differ substantially in the level of effort and time required and the chances of success. An overview of these options is provided below.

Option 1: Review of regulatory investment processes and application

This option is based on the view that promoting efficient investment in the DTS is primarily, or exclusively, a question of better regulation. Under this option a holistic review could investigate all factors affecting the efficiency of investment in the DTS (including investment in export capacity), indicatively to:

- understand the extent of the investment problem in the DTS (if any);
- identify the root causes of the problems including:
  - the current drafting of the investment related rules in the NGR (ie, rules 79-86);
  - the application of the relevant rules by the AER and the owner of the DTS; and
  - the planning process.
- consider the extent to which the rules and investment process are sufficiently flexible to enable the owner of the DTS to respond to changes, such as those that are currently underway in the market; and
- identify potential solutions (if any). To the extent the solutions require any changes to the drafting of the rules, then careful consideration will need to be given to the effect this may have for other regulated pipelines in eastern Australia, the Northern Territory and Western Australia.

The review could also consider whether the current process of allowing the owner of the DTS to retain any revenue derived from the auction of AMDQ credits or any other factors may be affecting investment incentives.

Essentially this review would build on, and investigate in more detail, the matters identified in the preceding sub-section. Importantly, the review should seek to improve common understanding of the issues. Conceivably, the review may provide comfort that investment in the DTS is being undertaken satisfactorily or alternatively may recommend changes to address any identified shortcomings.

If this option is considered appropriate, we would recommend the review be sponsored by SCER and carried out by the AEMC.

Option 2: Investigate and if feasible implement transmission rights

This option is based on the view that promoting efficient investment in the DTS is a question of better market design.

VENCorp undertook a detailed review of the DWGM in 2004, which recommended introducing tradable transmission rights to address congestion and investment issues in the DTS. Some insight into how VENCorp saw this working can be found in the following extract: [226]

> "The objective is to further develop AMDQ into transmission rights that are a consistent single product that addresses within-day constraints and "free-rider" issues. Accordingly, and as a first step, AMDQ is to be progressively modified into a single product, being a transmission right, which provides better physical, financial and competitive certainty, and is firm and readily tradable by the market."

We have not investigated why this aspect of VENCorp's recommendation was not progressed but possibilities include:

- transmission rights may not provide sufficient incentive to promote investment[227] (although transmission rights could still be justified as a more efficient way of managing pipeline congestion the current AMDQ system);
- the complexity involved in making such a change to the design of the market. Note that tradable transmission rights do not appear to have been introduced in any other gas market; and
- the investment and congestion-related benefits of making the change may not be considered sufficient to warrant the costs involved in introducing transmission rights.

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226 VENCorp, Victorian Gas Market Pricing and Balancing Review – Recommendations, 30 June 2004, p.11.

227 We understand that it is now generally accepted that FTRs in meshed electricity transmission grids do not generally provide adequate signals for investment. See for example the following extract taken from *Financial Transmission Rights in Europe's Electricity Market* Duthaler and Finger, November 2008, p.2:

> "Regarding transmission investment, the whole concept of merchant transmission investment relies on the idea that merchant investors receive FTRs to the extent that they add new capacity to the network. The benefits of allocated FTRs then would refund the initial investment over time. Experiences in most US markets indicate however that a pure merchant transmission approach is not enough to upgrade the grid sufficiently, especially if the grid upgrade relieves congestion and lowers the benefits of FTRs. In this case, the merchant approach fails and a regulatory approach has to be applied, including investment costs into regulated tariffs."

It has been nine years since the last detailed review of these issues was carried out and the investment issues have persisted over this period. This suggests there would be value in the AEMC undertaking a preliminary internal review into the potential for introducing tradable transmission rights into the DTS. Such a review could assist the AEMC's understanding of the decisions made in the 2004 review and provide an informed basis for considering whether a more extensive public review process might be justified.

A full review, if undertaken, is likely to require a number of complex issues and efficiency trade-offs to be considered and, in some ways, will be akin to the AEMC's Transmission Frameworks Review. Given the substantial resources required, we would suggest the AEMC establish whether there is a reasonable chance of success before undertaking such a review. In particular, the conceptual questions of whether tradable transmission rights could provide improved investment signals (and not simply improved management of congestion) would need to be assessed. Analysis of transmission rights in electricity markets should also be undertaken as part of this work.

Finally, it is worth noting that some stakeholders have suggested that many of the issues outlined above could be addressed if the market carriage model was replaced by the contract carriage model. One important point to bear in mind when considering the applicability of the contract carriage model in Victoria, is that the meshed network nature of the DTS (see section 6.1) means that it can be difficult to define exclusive capacity rights in a meaningful way. It may not therefore be possible to apply the contract carriage model in Victoria. That is not to say there may not be ways of improving access rights within the market carriage model (for example as proposed by VENCorp in 2004), but the solution is unlikely to be as simple as just switching to the contract carriage model.

Assessment of options

Of the two options set out above, we are of the view that:

- a review of the investment related regulatory processes and application (Option 1) could be undertaken in a timely manner, would not be overly complex, may produce workable improvements and would still be of benefit even if a review of tradable transmission rights occurs; and
- a review of tradable transmission rights (Option 2) would be complex, time consuming and at this stage does not have a clear prospect for success. However, if there is a feasible solution it could produce superior investment outcome compared to regulation. Before progressing down this path, we would therefore suggest the AEMC carry out an internal review on the prospects for introducing tradable transmission rights and only proceed to a more detailed public review if such rights are considered likely to provide improved investment signals in the DTS (and not simply improved congestion management).

At this stage we would recommend commencing work on Option 1 and the internal review under Option 2, but only proceeding to the detailed review if the internal review reveals it is likely to be beneficial. In terms of who should be responsible for carrying out either of these reviews and what priority it should be accorded, we are of the opinion that:

- SCER should sponsor the review(s) while the AEMC should carry out the review(s); and
- there is no great urgency for either review to be carried out given investment and exports are currently occurring. However, if a decision is made to go down either of these paths, they would ideally be carried out in the next one to two years, so that any recommended changes to the NGR, can be reflected in the next access arrangement, to be reviewed in 2017.

11.5.3 Contract carriage model

Unlike the Victoria market carriage model, investment in contract carriage transmission pipelines reportedly has been timely and efficient. We understand, however, that questions have been raised by SCER and AEMO about the efficiency with which fully contracted contract carriage pipelines are being utilised and that they are both currently exploring options to encourage a greater degree of capacity trading (see section 6.3).

At the outset it is worth pointing out that it is difficult to determine the significance of this issue given the lack of data on the extent of secondary trading that occurs, or the level of unmet demand for this type of service. However, based on our review of the incentives and abilities of shippers and pipeline owners to on-sell spare contracted but unutilised capacity (see section 5.4) and the feedback received from stakeholders (see section 10.2.2), it would appear that:

i. Both shippers (through a capacity trade) and pipeline owners (through 'as available' contracts)[228] can sell unutilised contracted capacity and there are no significant commercial[229] impediments to these types of transactions taking place.

ii. Apart from pipelines with multiple injection and withdrawal points (eg, the RBP), there do not appear to be any technical impediments to these types of transactions occurring.

iii. Shippers and pipeline owners should have an incentive[230] to sell any spare capacity and, in theory, should compete against each other to sell the capacity. The latter of these points is of particular importance, because while a shipper may appear to have little incentive to sell spare capacity to a downstream competitor, the fact that a pipeline owner can sell that same capacity on an 'as available' basis, should encourage the shipper to compete to supply the service and recover some of its fixed transportation costs.

228 If the *contracted* capacity is not being fully utilised by the contracting shipper(s), a pipeline owner may offer the unutilised capacity to other shippers on an 'as available' basis. For transactions involving the transportation of gas more than one day ahead, the capacity can only be sold on an 'as available' basis because it is possible that the contracting shipper may decide to use its entire MDQ reservation on any particular day. For spot or day ahead sales of transportation services, pipeline owners can offer a service that is more akin to a firm service than an 'as available' service because it will know what its shippers' nominations are when such transactions are entered into.

229 Shippers can sell their capacity through either a bare transfer or a novation.

230 A pipeline owner should have incentives to sell capacity because the capacity has already effectively been paid for by the contracting shipper (ie, because transportation charges are largely fixed and are payable irrespective of the volumes transported), so it will derive additional revenue from the sale. A shipper's incentive will depend on the opportunity costs associated with not entering into the transaction (which can be quite high because transportation costs are predominantly fixed) and commercial considerations, such as the effect the transaction may have on the buyer's competitive position in a downstream market.

iv. 'As available' capacity trades or sales by pipeline owners are only likely to occur at the margin because the nature of most buyers' gas requirements is such that they require access to firm transportation services. The potential exceptions to this are gas fired peaking generators, customers that can readily switch between alternative fuels and buyers with a portfolio of gas supply and transportation contracts and multiple uses for gas (eg, retailers that have gas fired generation interests and retail customers in multiple locations).

v. In terms of the transaction and co-ordination costs associated with these types of trades, it would appear that a distinction can be drawn between:

- spot or very short term trades – the transaction and co-ordination costs for these types of trades, when expressed on a $/GJ basis, are likely to be:
  - relatively high for formalised[231] capacity trades because shippers are unlikely to have the contracts or processes in place to readily enter into these types of transactions and many of these costs are likely to be fixed (eg, contract negotiation costs); and
  - lower for 'as available' transactions, because pipeline owners have established processes (eg, standard contracts) in place to minimise transaction costs.[232]
- other longer term transactions (eg, monthly, seasonal or longer term transactions) – the transaction and co-ordination costs in this case, when expressed on a $/GJ basis, will be much lower, because fixed costs will be spread across a greater volume of gas.

It is possible, therefore that the transaction and co-ordination costs associated with entering into spot or very short term *capacity* trades could act as an impediment to trade, but the same is unlikely to be the case for 'as available' transactions over the same period, or for longer term capacity and as available trades.[233]

Based on this synopsis, it would appear that a distinction can be drawn between:

- the ease with which trades of different duration can be entered into; and
- capacity trading on pipelines with multiple injection and withdrawal points versus simpler point-to-point pipelines.

These issues are explored in further detail below.

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231 We understand that these types of trades can also be carried out informally and may not involve the use of contracts.

232 Note also that there are unlikely to be any additional co-ordination costs under these transactions because the pipeline owner and prospective shipper deal with each other directly rather than through the shipper.

233 The transaction and co-ordination costs are likely to be relatively high for short term capacity trades because shippers are unlikely to have processes in place to deal with these transactions and many of the costs (eg, contract negotiation) are likely to be fixed. These costs are likely to be lower for 'as available' transactions, because pipeline owners have established processes (eg, standard contracts) in place to minimise transaction costs. For longer term contracts, the transaction and co-ordination costs, when expressed on a $/GJ basis, will be much lower, because the fixed costs are spread across a greater volume of gas.

Longer term trades (eg, monthly, seasonal or long term trades)

Setting aside for one moment spot or very short term trades, the synopsis above suggests that:

- both shippers and pipeline owners have the appropriate incentive and ability to sell unutilised contracted capacity; and
- transaction and co-ordination costs are unlikely to act as an impediment to longer term capacity trades or sales of 'as available' services by pipeline owners.

There does not therefore appear to be any failure in this segment of the market that would require the introduction of a regulatory measure to encourage a greater level of this type of trading. While on this topic, it is worth pointing out that if heavier handed regulatory measures were implemented to encourage a greater level of capacity trading then, apart from imposing costs on the market, they could have a deleterious effect on investment in contract carriage pipelines if they undermine the firm capacity rights held by shippers.

One only has to consider the issues raised about the effects of delayed investment in the DTS to realise that if the market driven investment signal is undermined it can adversely affect the productive efficiency of these pipelines, give rise to congestion and have a range of other adverse consequences for producers located upstream of the pipelines, shippers, downstream markets and, ultimately, consumers. We would therefore caution against the use of such measures unless there is a clear market failure and the benefits outweigh all of the costs (including losses of investment efficiency) that would be associated with implementing such a reform.

Spot or very short term trades

Turning now to very short term trades of pipeline capacity (eg, spot trades). It is possible, as noted in point iv, that the transaction and co-ordination costs associated with formalised capacity trades could act as an impediment to these types of trades, because shippers are unlikely to have standardised contracts or processes in place. It is less clear, however, these would act as an impediment to sales of 'as available' services by the pipeline owner, because they are more likely to have established processes in place to minimise transaction costs.

Whether or not there is much demand at this time for very short term capacity trades is another question. However, the following observations tend to support stakeholders' view that such trades are only likely to occur at the margins during the normal course of events:

- There is continued reliance placed by market participants on medium to long term firm gas supply and transportation contracts to meet their gas requirements (see section 5.1).
- Very few buyers are able to utilise additional gas (ie, over and above their contracted quantities) on a spot basis or for very short periods, with the list of buyers potentially limited to gas fired peaking generators, customers that can readily switch between alternative fuels and buyers with a portfolio of gas supply and transportation contracts and multiple uses for gas (see sections 3.1 and 5.7).

The term 'normal course of events' is used in this context because during a major gas supply shortage, it is possible that more of this trade will be required (either through formal or informal trades) to enable gas to flow to those that value it most during such extreme events. It is also possible that the introduction of the Wallumbilla gas supply hub and the development of a day-ahead and balance of the day gas product may encourage more of this trade to occur amongst the small number of players located in this area.

While we recognise that spot and very short term capacity trades are only likely to occur at the margin, there may be some value in trying to reduce the search, transaction and co-ordination costs associated with these types of trades, so that these types of trades can occur more readily. Some measures that would be useful to consider in this context include:

- developing standardised contracts for use by shippers; and
- developing a new section on the Bulletin Board (in accordance with rule 176 of the NGR) that can be used by participants to notify others they have spare capacity for sale or that they wish to purchase capacity.

Ideally, this work would be led by industry, or they would be closely involved in identifying solutions to this issue, given they are the ones that will be involved in the transactions and have a good understanding of their transportation requirements and contracts.

Capacity trading on point-to-point pipelines with multiple injection/withdrawal points

One other point of distinction raised in a number of discussions with stakeholders is the potential for technical impediments to defining capacity on pipelines with multiple injection and withdrawal points (notably the RBP) to affect the ability of shippers to trade capacity. This is because the available capacity on one part of such a pipeline can depend on what is being injected and withdrawn on another part of the pipeline.[234]

This means that trades between parties using different injection and/or withdrawal points can be difficult to co-ordinate from a system operation perspective; because the optimal solution depends on understanding the intentions of all affected parties in regard to injections and withdrawals at a point in time.

Given that this impediment to trade stems from the relevant physical characteristics of the pipeline, it is unlikely that any of the solutions being considered by SCER or AEMO will give rise to efficiency improvements from additional capacity trading on these types of pipelines.

234 This is similar in some ways to what occurs on a meshed network like the DTS.

11.6 Regulation of gas pipelines

On the whole, it would appear from our review that the gas pipeline regulatory provisions set out in the NGL and NGR are working relatively effectively and have sufficient flexibility to deal with the changing market conditions.[235] Having said that, we understand concerns have been raised by some stakeholders about:

- the effect that differences in the regulatory status and forms of regulation applied to transmission pipelines may have on shippers trying to transport gas between different jurisdictions;
- the form of regulation applied to distribution pipelines; and
- the effect that certain provisions in the NGR, or the application of those provisions, may have on investment.

It would also appear from our examination of the changes underway in the market (see section 11.1), that changes in the utilisation of regulated pipelines could test the efficacy of the regulatory arrangements. These issues are considered, in turn, below.

11.6.1 Different forms of regulation

Based on our review, it is unclear to what extent differences in the regulatory status or form of regulation are really an issue for shippers seeking access to multiple contract carriage pipelines, because, irrespective of whether the pipeline is regulated (full or light) or not, shippers must still negotiate access with the pipeline owner. The only substantive difference is that when negotiating access to a transmission pipeline that is subject to full (light) regulation, the reference (published) tariff provides a reference point for negotiations and if a dispute arises on a regulated pipeline (full and light), the shipper has recourse to the dispute resolution mechanism.

While the lack of an equivalent reference point or dispute resolution mechanism for unregulated pipelines may appear to be a gap in the current regulatory framework, it is important to recognise that most unregulated transmission pipelines compete with another pipeline to supply a demand centre. It is competition that therefore acts as a constraint on the unregulated pipeline owner's pricing behaviour rather than regulation.[236] The fact that access to some pipelines is not regulated under the NGL and NGR should not therefore, in and of itself, be considered a gap in the current regulatory framework.[237]

It follows from the preceding discussion that while we understand that differences in the regulatory status and form of regulation may be confusing, it is not obvious that this is

235 Through the coverage, light regulation and greenfield provisions in the NGL and a number of the regulatory provisions in Part 9 of the NGR.

236 It is worth reiterating that unregulated pipelines are still subject to the general competition provisions in the *Competition and Consumer Act 2010*.

237 The coverage (and form of regulation provisions) in the NGL are founded on sound economic principles and if there are genuine concerns about particular pipelines, then an application can be made to the NCC seeking coverage.

imposing any additional costs or inefficiencies on shippers seeking to move gas between multiple jurisdictions. We are not therefore suggesting any further work be carried out on this issue.

11.6.2 Regulation of distribution pipelines

In a number of discussions with stakeholders, it was claimed that distribution pipelines can possess a greater degree of market power than transmission pipelines and should therefore be regulated in the same manner as electricity networks. It was not clear however from stakeholder feedback whether their concerns related to differences in the specification of the rules in the NGR and NER, or to the proportion of a pipeline owner's revenue that may be subject to regulatory review (see section 10.2.3.1).

In our opinion, the relevant question to consider in this context is *not* whether the same regulatory framework should be applied to distribution pipelines as that which is applied to electricity networks. Rather, the question is whether the current regulatory framework is fit for purpose, targeted and proportionate to the problems it seeks to address. Based on the discussions held with stakeholders, there does not appear to be any suggestion that the current regulatory framework is not achieving these outcomes.

The other general observation we would make is that it is not clear that applying the electricity regulatory framework to gas distribution pipelines would result in a significant change in the productive, allocative or dynamic efficiency of the pipelines, or otherwise better promote the NGO, given that:

- in substance most of the rules in the NGR and NER are designed to achieve the same outcomes;[238] and
- the majority of services provided by regulated distribution pipelines tend to be classified as reference services, which means a large portion of revenue is subject to regulation.

We are not therefore recommending any further work be carried out on this issue at this time.

11.6.3 Investment related rules

In terms of the investment related rules, concerns have been raised about the potential for the following provisions (or the application of these rules by the regulator) to create uncertainty, or to otherwise affect, investment decisions by the owners of regulated pipelines (see section 10.2.3.2):

- the advance determination of future capital expenditure provisions (rule 80);
- the speculative capital expenditure provision (rule 84(2)); and
- the redundant asset provisions (rule 85).

[238] For example, while different terminology is used in the operating expenditure test in the NGR and NER, they are both designed to only allow operating expenditure to be approved if it is such as would be incurred by a prudent service provider acting efficiently.

In relation to rule 80, we expect that as part of a review of regulatory investment processes and application in Victoria (see section 11.5.2.2), this provision would be closely examined to determine whether it is achieving its stated objective. In terms of the concerns raised about rules 84(2) and 85, we suggest that, to the extent they are adversely affecting efficient investment decisions, affected stakeholders are best placed to consider submitting a rule change proposal to the AEMC.

11.6.4 Changing pipeline utilisation

As noted in section 11.1, the changes underway in the market may result in significant changes in the utilisation of some pipelines. Based on our review of the NGR, the existing regulatory framework appears to provide sufficient flexibility to deal with these changes. For example:

- Rule 89 of the NGR allows the depreciation profile to be aligned with the utilisation of the pipeline, so to the extent there is a transitory reduction (increase) in utilisation, this could be accommodated by back end (front end) loading depreciation.
- Rule 85 of the NGR allows any assets that cease to contribute in any way to the delivery of services to be removed from the capital base and for the effect of this removal to be shared with users. Rule 86, on the other hand, allows any redundant assets that later contribute to the provision of services to be rolled back in.

Given the flexibility that already exists within the NGR, we do not think this issue needs to be considered any further from a market development or rule making perspective. We would, however, suggest that if there is a reduction in the utilisation of a pipeline, regulators should carefully consider whether or not to use the redundant asset provisions, given the potential adverse effect on investment.

11.7 Retail markets

Based on our understanding of the retail arrangements (see section 7.6) it would appear that the harmonisation of consumer protection frameworks that has occurred through the NECF should substantially reduce the costs, complexities and barriers to entry faced by retailers operating across multiple jurisdictions, with consumers being the ultimate beneficiaries. While over time it may become apparent that further efficiencies in the retail segment can be achieved by amending this new regulatory framework, it is not obvious at this point in time that any further work needs to be carried out.[239]

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[239] Two other issues that a number of retailers raised are that:

- the different information systems used to support business-to-business processes in NSW/ACT *vis-à-vis* other jurisdictions are giving rise to additional costs. On the information before us, it is difficult to determine how material an issue this is and whether the benefits of harmonising these processes are likely to outweigh the costs. We understand, however, that the AEMC has sought further information on this issue in the context of the NSW retail competition review and that this issue has recently been considered by AEMO's Gas Retail Consultative Forum. Given this issue already appears to be in hand, we are not recommending any additional work be carried out on this issue; and

In terms of retail price regulation, one potential risk we have identified with the changes underway in the market (see section 11.1) is that, as the effect of higher wholesale gas prices start to flow through to residential customers, policy makers may try to protect residential customers from higher gas prices by:

- reintroducing retail price caps in those jurisdictions that have removed retail price regulation; and
- implementing retail price caps that prevent retailers from recovering their efficient costs.

While there has been no indication that any jurisdictions are currently considering this type of response, it is possible that once the effects start to flow through to residential prices in 2015-2018 (see section 4.4.2) some consideration may be given to this option. Given the potential for this type of response to adversely affect the viability of retailers and retail competition, more generally, we suggest the AEMC keep a watching brief and if there is any indication this option may be pursued, the AEMC should liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition.

11.8 Information

During the consultation process a number of stakeholders raised concerns about:

- the level of information currently available on the Bulletin Board;
- the fact that some facilities are not designated Bulletin Board facilities; and
- the quality and accessibility of the existing STTM, DWGM and Bulletin Board data.

On the first of these issues, we understand AEMO carried out a review into the information that should be made available through the Bulletin Board in 2011/12 and will shortly be submitting a rule change proposal to the AEMC.[240] Since this review considered many of the issues identified in section 10.6 and stakeholders will have an opportunity to participate in the upcoming AEMC consultation process, we are not recommending any further work be carried out on this issue.

On the second issue, we agree that AEMO should consider whether the current list of designated facility operators is appropriate, given the changes currently underway in the market, and, if necessary use its declaration powers under rule 153 of the NGR.

On the third issue, we agree that the quality and accessibility of some elements of the STTM, DWGM and Bulletin Board data could be improved. However, it is unclear how material this issue is for the market or what the costs are likely to be of addressing this issue. We are not

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- there should be a greater degree of harmonisation between the terms and conditions specified in distribution pipelines' access arrangements and, in particular, the payment terms and indemnity provisions. Once again, it is unclear how material an issue this is but to the extent it is an issue, we are of the view that the AER's access arrangement review process is the appropriate forum to deal with this type of issue for those distribution pipelines that are regulated.

240 AEMO, Final Report: Gas Market Information – Gas Bulletin Board, 30 March 2012.

therefore suggesting a discrete piece of work be carried out on this issue, but we suggest the AEMC encourage AEMO to consider this further and engage with industry through its consultative forums to determine what, if any, improvements could be made.

Another issue raised by one stakeholder is the need that buyers and producers have for greater transparency about the costs of transporting gas between various locations in south eastern Australia and Gladstone if LNG netback pricing is to become the predominant form of pricing in eastern Australia.[241] While we can see that in this new paradigm of LNG netback pricing, there may be merit in a common transportation cost reference point from different supply sources being established,[242] we would expect this type of information could be provided on a more cost effective basis by a market information provider(s), rather than by imposing additional obligations on pipeline owners. We are not therefore recommending any further work be carried out on this issue at this stage.

11.9 Greater interaction with the NEM

AEMO's current outlook for gas fired generation in the NEM is that demand from this segment will fall by 17% between 2012 and 2020 and that no new gas fired generation investment will be required until at least 2025.[243] On current projections, the greater degree of convergence that was previously expected to occur between the gas and electricity markets appears to be some way off. It would also appear from our own high level review that the existing arrangements in the gas market have not imposed any significant imposts or risks on gas fired generators to date,[244] or otherwise affected the efficiency of this sector.[245]

Given the conditions prevailing at this time, there does not appear to be any immediate urgency to undertake a review into whether a greater degree of interoperability, risk management and consistency between the NEM and imbalance markets would be beneficial. Having said that, we do think there would be value in either:

- a detailed review being carried out by the AEMC in the medium term (or if there is a significant change in climate change polices and/or conditions in the NEM that supports gas fired generation), to get a better understanding of the interactions between the two markets and to ensure that the existing arrangements are fit for purpose; or

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241 Note that currently, owners of regulated pipelines (full and light regulation) are required to publish their tariffs but owners of unregulated pipelines are not.

242 The availability of this common reference point could eliminate a potential source of dispute when new gas supply agreements are being negotiated.

243 AEMO, Gas Statement of Opportunities, 2012, Figure 1 and Figure A-13.

244 While some gas fired generators have claimed that differences between the market price caps prevailing in the NEM and the imbalance markets may give rise to arbitrage opportunities (see section 10.7), this does not appear to have been a significant issue to date because none of the STTMs have reached the market price cap and the last time it was reached in the DWGM was in November 2008 when it prevailed for one pricing period.

245 While that is not to say this could not occur in the future, it is something that should be borne in mind when considering the priority to be accorded to this issue.

- having the AEMC or AEMO consider the question of whether a greater degree of consistency between the market parameters in the NEM and the imbalance markets is appropriate, as part of the STTM and DWGM review (see section 11.4).

Given stakeholders have to date only focused on the potential benefits that may arise if there is a greater level of consistency between the market price caps and prudential requirements, we would recommend pursuing the latter option in the first instance and only carrying out a detailed review if a greater degree of convergence between the gas and electricity markets becomes more likely.

One point that will need to be borne in mind if the latter option is pursued is that gas fired generators currently only account for around 30% of the gas consumed in eastern Australia (see section 3.2). Careful consideration will therefore need to be given in such a review to:

- the risks that the remaining 70% of the market will be exposed to if the market price cap or prudential requirements in the STTM and/or DWGM are revised, the implications that these risks may have for gas consumers[246] and any other costs the changes may impose on market participants;
- the frequency with which any arbitrage opportunity is likely to arise between the two markets, the opportunity costs associated with such events and the effect that such events may have on electricity consumers, which will require a detailed assessment to be carried out on the interaction between prices and risk in the imbalance markets and the NEM;[247] and
- whether the benefits of eliminating the potential for arbitrage to occur across the markets are likely to exceed the costs and risks imposed on the remaining 70% of the market.

Any assessment of the consistency question will also need to take into account the differences between the design of the NEM, STTM and DWGM and the risks faced by parties in these markets.

As the preceding discussion highlights, greater consistency between the NEM and imbalance markets should not be pursued for consistency's sake. Rather, consistency should only be pursued if material problems are identified and the benefits of addressing the problem are judged to outweigh the costs and it is consistent with both the NGO and the National Electricity Objective.

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246 For example, if the market price cap is reached and a retailer is unable to meet its obligations then this is likely to prompt the exit of that retailer, which will have broader implications for retail competition.

247 This will likely involve an actuarial type study.

11.10 Emergency arrangements

The arrangements put in place to deal with emergencies extending beyond one jurisdiction are the final area of the current gas market arrangements that, in our opinion, warrant further consideration.

In principle, effective emergency management arrangements should exhibit the following characteristics:

- From a legal and regulatory framework perspective:
  - Powers and obligations should be clear, transparent, and binding.
  - Decision makers should be clearly identified in each jurisdiction.
  - The extent of immunities, if any, for decision makers should be clear and unambiguous.
  - The framework should enable and require timely provision of relevant information to decision makers.
  - Obligations should be supported by a targeted, fit-for-purpose monitoring and enforcement regime.
- From an economic perspective:
  - The arrangements should allow and encourage market responses where feasible to address problems as they arise.
  - Risks should be allocated as efficiently as possible, and the risk allocation should be clearly understood by those who bear the risks.
- From an operational perspective:
  - Emergency governance and communication arrangements should be clear and publicly available.
  - Arrangements should be subject to regular practical testing and reviews.
  - Appropriate resources should be made available by government and industry to support emergency decisions, operational reviews and ongoing compliance.

It is beyond the scope of this study to consider whether the current arrangements exhibit all of these characteristics. Our high level review has instead focused on whether the arrangements established through the National Gas Emergency Response Protocol Memorandum of Understanding are likely to satisfy the following criteria:

- transparent and publicly available;
- clearly specifies the obligations, accountabilities and any indemnities of decision makers and advisors;
- provides for timely and informed decision making during an emergency;

- to the extent possible, allows the market to allocate gas to those that value it most when there are shortages; and
- the arrangements are tested on a frequent basis.

We have also considered whether AEMO and industry have the right level of involvement in the process.

In short, it would appear from our review of these arrangements (see section 7.8) and the high level feedback provided by stakeholders (see section 10.8) that:

- AEMO and industry have the right level of involvement in the process through NGERAC.
- The arrangements appropriately recognise the role that the market can play in managing gas shortages before a jurisdiction needs to consider exercising its emergency powers.
- The emergency arrangements are tested on a relatively frequent basis.

It would also appear from our discussions with NGERAC members that stakeholders consider the arrangements to be working relatively well and that active steps have been taken to improve certain processes, such as emergency management co-ordination services, information provision and the modelling used during emergencies.

Although there do not appear to be any significant issues with the existing arrangements, it is clear from our discussions with stakeholders and our own attempts to understand how the arrangements operate, that there is a lack of clarity around:

(i) the roles and responsibilities to be played by NGERAC in a major gas supply shortage;

(ii) the role to be played by AEMO, both within NGERAC and during a major gas supply shortage;

(iii) the circumstances in which NGERAC will be convened;

(iv) any immunity NGERAC and AEMO may have from liability;

(v) the principles that should underpin the jurisdictional curtailment tables and commercial gas sharing arrangements; and

(vi) the obligations that industry has to provide NGERAC with information during a major gas supply shortage or an emergency and the level of information to be provided.

While we understand that some of this information can be found in the National Gas Emergency Response Protocol Memorandum of Understanding (MoU) (eg, (i)), other elements appear to be dealt with in procedures and/or reports that are not publicly available (eg, (iii) and (iv)), while other elements, as far as we can ascertain, do not appear to have been formally documented (eg, (ii) and (v)).

It is difficult to quantify the materiality of this issue, given the small number of occasions on which the emergency arrangements have been triggered. However, given the changes underway in the market and the potential for some jurisdictions to become more exposed to emergencies in other jurisdictions in the future and some more complex issues to be considered if curtailment is required[248] (see section 11.1), we think there would be some value, from a both a reliability and security of supply perspective, in doing the following:

- Formalising industry's obligations to provide NGERAC with information in an emergency. While we understand information has been forthcoming in the past, we are of the view that a greater level of clarity amongst all parties about their respective obligations could be beneficial and reduce the potential for unnecessary delays in information provision in an emergency.
- Having AEMO carry out a review to determine whether there are any additional pipelines, production or storage facilities that should be deemed Bulletin Board facility operators, because there appear to be some gaps in this area at present (see section 10.6).
- Improving the transparency and accessibility of the existing arrangements and addressing the issues set out in items (ii)-(v) by either:
  - updating the existing MoU; or
  - moving the emergency arrangements into the NGL/NGR and ensuring that, in addition to the material already contained in the MoU, items (ii)-(v) are dealt with either in the NGR or through procedures/guidelines that are provided for in the NGR and are made available in a central location.

  One benefit the latter of these options has is that liability and indemnification issues can be dealt with more readily through the NGL or legislation than it can through a MoU. It is also consistent with the way in which the Victorian arrangements are treated.
- Having NGERAC carry out a review of the jurisdictional curtailment tables to determine whether they are appropriate given the changes currently underway in the market[249] and consistent with the curtailment principles we understand it has developed. One other issue that should be considered in this review is whether the jurisdictional curtailment tables should be made publicly available. While we understand there may be some political sensitivity to this, producing a similar level of information to that contained in AEMO's *Victorian Gas Load Curtailment and Gas Rationing and Recovery Guidelines,* could be beneficial to industry. In short, the publication of this type of information would provide industry with a better idea about the likelihood they will be curtailed, allow them to choose how to manage the risk (eg, through insurance) and enable them to put in place the necessary arrangements *before* a jurisdiction exercises its emergency powers.

Given that the emergency arrangements do not currently form part of the NGR and that any work in this area will require the agreement of the jurisdictions, we would recommend the AEMC refer the stakeholder comments and our high level findings to SCER and DRET, who may then consider whether to take the suggested changes forward.

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248 For example, once the LNG projects are operational consideration may need to be given to how to ration gas amongst domestic and export customers if an emergency affects supply from the Cooper Basin or within Queensland.

249 For example, the curtailment tables in Queensland should be updated to recognise the LNG projects.

11.11 Summary of recommendations

The table below contains a summary of the recommendations set out in this chapter.

Table 11.1: Summary of recommendations

Recommendation	Responsibility	Timing
High Priority		
Strategic direction for future gas market development		
Undertake a strategic review that considers both: ▪ the direction that the eastern Australia gas market should take over the next 10-15 years, if it is to make the transition to a more mature, well-functioning market (consisting of commodity, transportation and financial markets) that supports: the efficient allocation of gas and transportation capacity in the short, medium and longer-term; the efficient trade and movement of gas between jurisdictions; efficient and timely investment in upstream production and transportation capacity; the efficient allocation of risks; and the development of financial markets that can be used by participants to hedge risks. As part of this assessment, consider would ideally be given to whether the existing facilitated markets (ie, the DWGM and STTM) are meeting their stated objectives in the most efficient manner and, if not, how this could be addressed; and ▪ the principles that should guide the development and design of facilitated markets in the future. A review of this nature is consistent with both SCER's gas market policy principle of 'promoting market development' and its policy objective of increasing the role of market to: ensure the most efficient allocation of gas resources and infrastructure; and increase market flexibility.	SCER to sponsor review. AEMC to carry out review.	2013-14
Detailed review of the design of the STTM and certain elements of the DWGM		
Undertake a detailed review of the design of the STTM and particular design elements of the DWGM and determine whether improvements can be made to the existing design that would better promote the NGO.	AEMC and SCER to jointly draft terms of reference. SCER to determine whether the AEMC and/or AEMO should carry out review once the scope of work defined.	2013-14
Medium Priority		
Time taken for STTM and DWGM rule changes		
Investigate ways of reducing the time taken to develop, review and implement STTM/ DWGM rule changes and streamline the consultation process.	AEMO and AEMC.	2nd half 2013
Improved investment under the market carriage model		
The two review options (not mutually exclusive) that could be taken to promote improved investment outcomes in the DTS include: Option 3: Undertake a holistic review of the regulatory investment process and application of this process in Victoria; and/or Option 4: Undertake a preliminary internal review on the prospects for introducing tradable transmission rights and proceed to a more detailed public review if tradable transmission rights are considered likely to provide improved investment signals in the DTS. Of the two options, we would at this stage recommend commencing work on Option 1 and the internal review under Option 2, but only proceeding to the detailed public review under Option 2 if the internal review reveals it is likely to be beneficial to implement tradable transmission rights.	SCER to sponsor review. AEMC to carry out review.	2014-15

Recommendation	Responsibility	Timing
Capacity trading under the contract carriage model		
Consideration to be given to how to reduce search, transaction and co-ordination costs associated with spot or very short term capacity trades (ie, capacity trades for periods less than one month) to facilitate this form of capacity trading by shippers. For longer term trades (eg, monthly, seasonal or longer term transactions), it would appear that shippers and pipeline owners have the appropriate incentive and ability to sell unutilised contracted capacity and that transaction and co-ordination costs are unlikely to act as an impediment to such trade. There does not therefore appear to be any failure in this segment of the market that would require the introduction of a regulatory measure to encourage a greater level of this type of trading.	Industry led.	2013-14
Low Priority		
Greater interaction with the NEM		
Assessment of whether greater consistency between market parameters in the NEM and imbalance markets to be carried out as part of the STTM and DWGM design review.	AEMC and/or AEMO depending on allocation of responsibility for review.	2013-14
If there is a significant change in climate change polices and/or conditions in the NEM that supports gas fired generation, then a more detailed review could be undertaken to get a better understanding of the interactions between the two markets and to ensure that the existing arrangements are fit for purpose.	SCER to sponsor review. AEMC to carry out review.	n/a
Retail markets		
Be cognisant of the potential for higher wholesale gas prices to prompt jurisdictions to implement a cap on retail prices that is lower than the efficient cost of supply and, if there is any indication this may occur, liaise with SCER and the jurisdictions and inform them of the longer term consequences that such a response may have on retail competition.	AEMC.	2015-2018
Information		
Consider whether any additional operators should be designated Bulletin Board facility operators. Consider whether improvements can be made to the quality and accessibility of existing STTM, DWGM and Bulletin Board data.	AEMO	2nd half 2013 or 2014
Other		
DWGM rule change proponents		
Refer stakeholder comments on the effect of the restriction on DWGM related rule changes to the Victorian DSDBI and allow it to consider whether there is still a rationale for having this restriction and, if so, whether any improvements could be made to the current process.	AEMC to refer to Victorian DSDBI.	2nd half 2013
Emergency Arrangements		
Refer stakeholder comments on emergency arrangements and our high level observations about the need: to improve the transparency and accessibility of these arrangements; formalise the obligations industry have to provide information in emergencies; review jurisdictional curtailment tables; and consider whether such tables should be publicly available to SCER and DRET.	AEMC to refer to SCER and DRET.	2nd half 2013