Australian Government
Department of Industry
Bureau of Resources and Energy Economics

Eastern Australian
Domestic Gas Market Study

Acknowledgements

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Cover photo (top image): Courtesy of Jemena. The Mila compressor station on the Eastern Gas Pipeline which is wholly-owned by Jemena. The Eastern Gas Pipeline is used to deliver natural gas to consumers in Victoria, New South Wales and the Australian Capital Territory.

Contents

Abbreviations and acronyms

2P	proved and probable (reserves)
3P	proved, probable and possible (reserves)
2C	contingent (resources)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGRA	*Australian Gas Resource Assessment*
APLNG	Asia Pacific Liquefied Natural Gas
APPEA	Australian Petroleum Production and Exploration Association
ASX	Australian Securities Exchange
BREE	Bureau of Resources and Energy Economics
CNOOC	China National Offshore Oil Corporation
COAG	Council of Australian Governments
CSG	coal seam gas
DOE	Department of Energy (US)
DWGM	Declared Wholesale Gas Market (Victoria)
GLNG	Gladstone Liquefied Natural Gas
GPG	gas powered generation
GSA	gas supply agreement
GTA	gas transportation agreement
IEA	International Energy Agency
IES	Intelligent Energy Systems
JCC index	Japan Customs-cleared Crude index
LNG	liquefied natural gas
MoU	Memorandum of Understanding
NEM	National Electricity Market
NGERAC	National Gas Emergency Response Advisory Committee
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
PGPLR policy	Prospective Gas Production Land Reserve policy
QCLNG	Queensland Curtis Liquefied Natural Gas
RLMS	Resource and Land Management Services
SCER	Standing Council on Energy and Resources
SEA Gas	South East Australia Gas Pipeline
SKM	Sinclair Knight Merz
STTM	short-term trading market

Units

$/GJ	Australian dollars per gigajoule
GJ	gigajoule
GWh	gigawatt hour
mmBtu	million British thermal unit
Mt	million tonnes
Mtpa	Million tonnes per annum
MW	megawatt
PJ	petajoule
TJ	terajoule
tcf	trillion cubic feet
TJ/d	terajoules per day

Executive summary

The Eastern Australian Domestic Gas Market Study is a joint project between the Department of Industry and the Bureau of Resources and Energy Economics (BREE). It was initiated in the context of the domestic gas market rapidly expanding in response to the advent of liquefied natural gas (LNG) export projects on the east coast and the associated uncertainty surrounding the outlook for supply and demand. The study is designed to help address information gaps and inform debate on strategy for gas policy. In particular, this work and continued engagement with stakeholders will inform the Eastern Australian Gas Supply Strategy to 2020 and the Energy White Paper.

The dominant issue that underlies the discussion, analysis and range of policy options presented in this study is the transition of the eastern gas market from being solely domestic to one that is export linked. The scale and duration of this change is likely to have profound effects on market participants. These effects will be exacerbated if impediments to supply or other constraints are imposed on the market's ability to respond to the challenge of future market dynamics.

Understanding this transition and its implications for the eastern gas market requires understanding of the market's key components – supply and demand, infrastructure, and the nature and role of trading mechanisms. This study examines each of these components and in doing so reveals several broad themes that relate to the need for the market to:

- provide sufficient and timely gas supply to meet expanded demand
- provide more transparent information in both the upstream and downstream sectors
- develop arrangements and mechanisms that facilitate its ability to meet the changing needs of participants and smoothly respond to future change.

The market is changing

Gas is Australia's third largest energy resource after coal and uranium. The historical development of the domestic gas market has served Australia well and has contributed to rapid growth in LNG project development opportunities. Figure ES.1 shows the location of current and committed eastern Australian gas market infrastructure, including pipelines, processing and storage facilities.

We are currently witnessing an unprecedented level of investment in the development of LNG projects on the east coast of Australia. It is creating thousands of jobs and business opportunities for Australians. The LNG projects are also a world-first, as no other country has developed LNG export trains based on coal seam gas (CSG) resources. The development of these facilities is also introducing a significant new dynamic into the eastern Australian domestic gas market.

Figure ES.1: Map of east coast gas market infrastructure
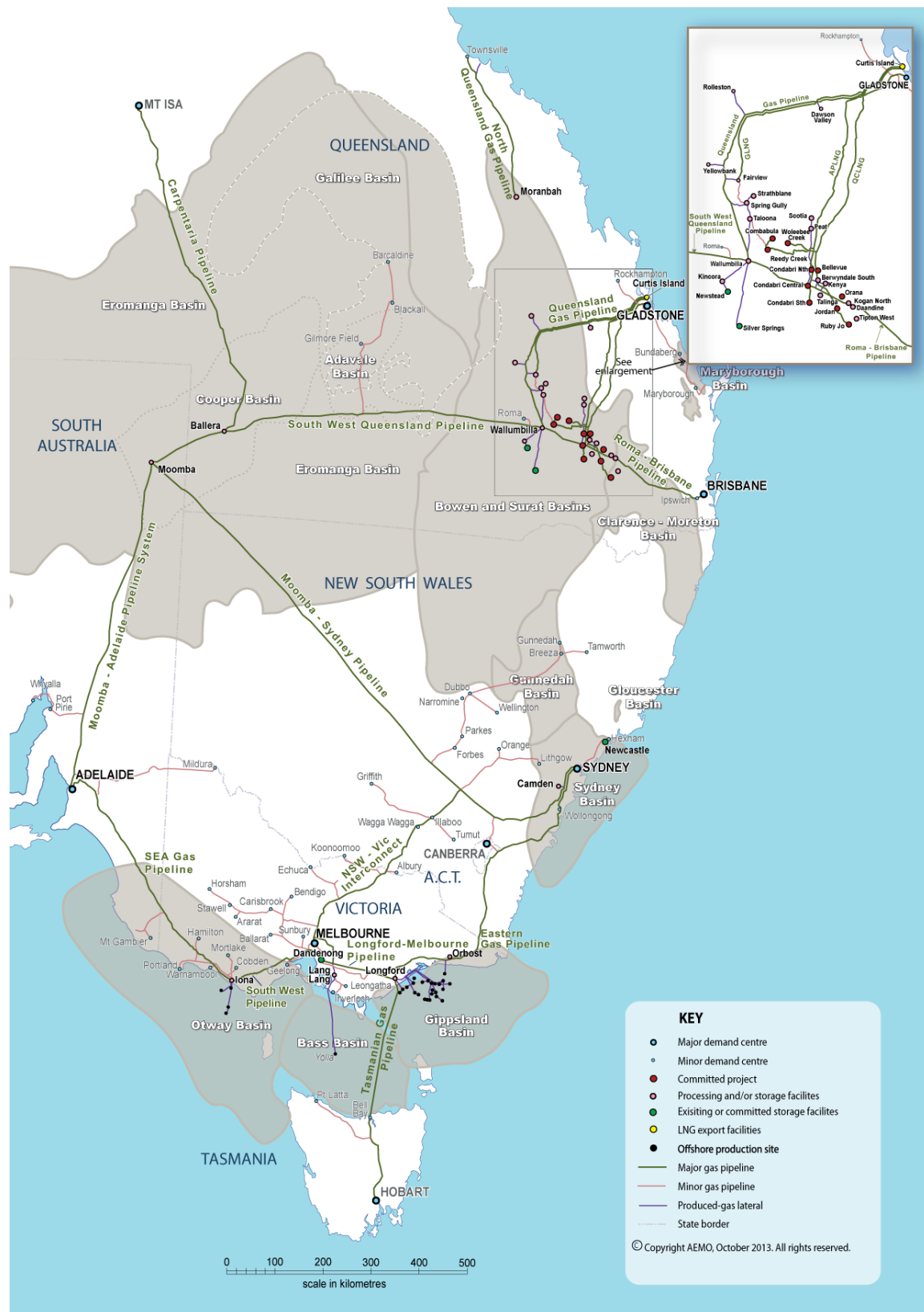
Source: AEMO (2013).

The previously stable and long-term contract market for domestic gas supply on the east coast will be subject to market forces that are in part determined on the global stage. Price increases are apparent in the latest offers to industrial users – and LNG production has not yet begun. Precisely how the market will respond and the nature of the transition to a more dynamic market is not yet clear. There are asymmetries of information in an opaque, long-term contract-based market and some new and large risks in the supply–demand balance that may affect the market's ability to respond quickly to changing circumstances.

Higher prices are also driven by assumptions about the number and timing of LNG trains and the diversion of uncontracted supply from domestic use to LNG production. To the extent that market power might be exercised in the presence of tight supply, prices could rise above netback prices and potentially be sustained for several years.

Implicit in the terms of reference for this study was the aim of providing greater clarity on forward price expectations. To meet this aim, modelling was commissioned around a range of plausible market scenarios. The modelled future gas prices remain higher relative to historical levels due to higher production costs, demand competition from Asian LNG opportunities and, as linked through contracts, the price of oil. Lower-bound prices based on the least-cost supply of gas show a gradual rise over time, mainly driven by rising costs of production. Noting modelled prices reflect their assumptions rather than negotiated outcomes, the study also reviewed outputs of alternative approaches which showed relatively higher price paths, including towards or exceeding LNG netback during the period of LNG plant commissioning.

While modelling was not able to establish a single reference price series, this is not unusual for complex markets. Quite rational interpretations of supply response, cost drivers, competitive behaviour and the ability of demand to accommodate price rises generate divergent expectations on price that are difficult to reconcile. This divergence has disrupted contracting activity and has the potential to create incentives for suppliers to delay striking deals until conditions are considered most favourable, and related challenges for gas users seeking long-term contracts.

The need for policy response

Rising prices do not automatically mean the market has failed or that intervention is necessary. While price discovery has been difficult for some time, the linkage to international markets has been coming for a number of years. All users will need to adjust to prices being set in a more dynamic and higher cost environment, particularly those domestic gas users who have had to adapt quickly after decades of fairly steady market fundamentals. Supply will respond to price and there are early signs of this starting to occur in eastern Australia.

When considering potential policy options, the extent and duration of any tightness in the market takes on particular significance. In a period of transition, there is a risk price may overshoot export parity until there is sufficient gas supply or information available to the market to overcome any transient market power and readjust risk expectations.

Long-run contracting, the potential for the exercise of market power and a lack of transparency may conspire to make this transition longer than it might otherwise be. Whether this risk is material is unclear to the extent that the level of market efficiency is not measurable (if we had confidence that the market was fully efficient, this risk would be low). Further consideration needs to be given to reforms that address and mitigate these risks.

Six areas of reform

This study outlines a range of options that could be considered by governments to address gas supply constraints and facilitate a well-functioning and transparent market. The options fall under six themes:

- gas market reform
- supply competition
- data and transparency
- infrastructure
- non-market interventions
- governance.

Figure ES.2 illustrates the six policy option themes and Figure ES.3 illustrates the range of potential outcomes that could arise from the adoption of these policy options. Which of these policy options to pursue is a matter for further detailed analysis and strategy development.

Figure ES.2: Possible policy options - themes

Figure ES.3: Potential outcomes from adopting the possible policy options
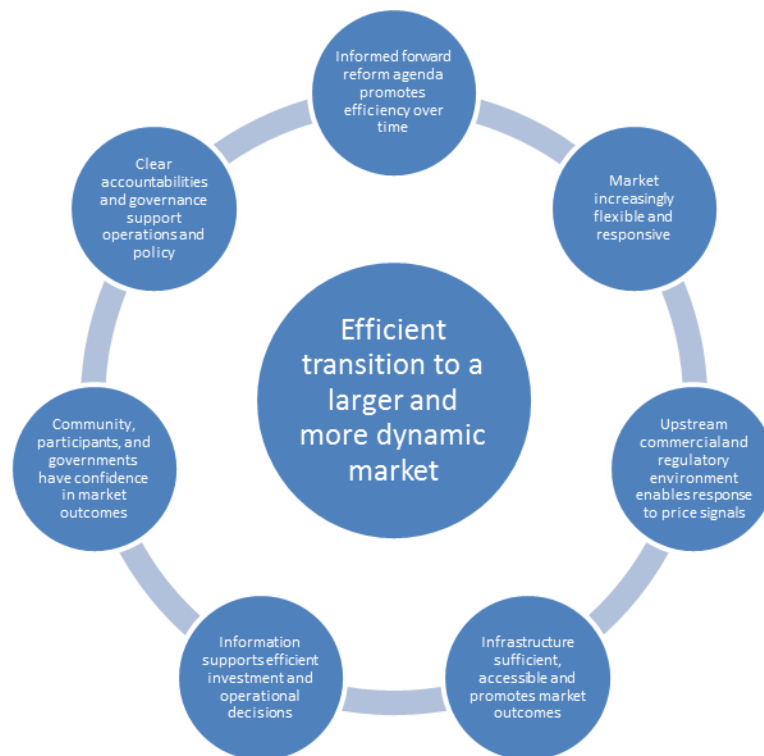
Information on supply and demand is important for building confidence in the efficiency of the market and informing policy development. For gas users, the key information asymmetry in the market – whether or not CSG production associated with LNG exports will fall short – will largely be resolved in the next few years. The later it is resolved, the more likely it is that the transition and adjustment process that follows price rises will be prolonged and more difficult than it might otherwise be. This study identifies a number of options that could improve this and other supply chain information sets to inform the regulatory reform agenda.

Facilitating and encouraging a supply response is also vital to dealing with any potential physical shortage and addressing supply uncertainty. Governments should focus on removing unnecessary impediments to developing new gas resources particularly during a period of tightness in gas supply and providing a certain and predictable regulatory and investment environment.

The interconnectedness of the market should not be used as an excuse for complacency about regulatory frameworks or market outcomes. Policy should be consistent across jurisdictions and levels of government and have a strong focus on improving accountability and governance of the domestic gas market.

Policy should seek to ensure that the operation and regulation of the market facilitates a smooth transition and provides the best opportunity possible for all market participants to adjust. In this way, the overall economy will reap the maximum benefits of the LNG developments while providing for an efficient domestic gas market. Care should also be taken not to disrupt commercial activities within the market.

The discussion on these issues raises broader questions about whether the eastern Australian gas market has now reached a point in its development where further reform is appropriate. There seems to be widespread support to use the current experience in the market as an opportunity to think more carefully about the forward market reform agenda.

There is a healthy debate on the lessons from Australian and international experience about the ability of governments to facilitate market change. Engagement with stakeholders to develop principles to guide the evolution of commodity, transportation and financial markets is crucial in this process if market reform is to be successful. Further reviews and research are also necessary.

A forward agenda could be developed in consultation with stakeholders as part of the government's proposed Eastern Australian Gas Supply Strategy to 2020, and clear and accountable milestones developed and progressed through the Standing Council on Energy and Resources (SCER).

Structure and approach

This report is structured in three parts:

Chapters 1 to 5 provide a snapshot of the current eastern Australian gas market and highlight the key drivers of investment decision-making throughout the different segments of the supply chain, detailing the impact of past gas market reform and identifying relevant regulatory lessons learned from other jurisdictions (domestic and overseas).

Chapter 6 covers the approach and key findings of gas market modelling and analysis by Intelligent Energy Systems (IES) who were commissioned for this study to improve understanding of the interaction between gas prices and supply in the eastern market and the nature of the current transition. To provide further context to IES's work, analytical advice purchased from Sinclair Knight Merz (SKM), coupled with a regular major report by Core Energy Group, and Australian Energy Market Operator's (AEMO) recently released *2013 Gas Statement of Opportunities* were also assessed.

Chapter 7 considers policy responses in the light of issues identified in the supply and demand sides of the market resulting from the factors discussed in chapters 1 to 6. It examines the key barriers to future gas market development in Australia and options available to policymakers to address impediments to supply and improve the response to new dynamics in the market.

The contents of this report were drawn from analysis of data, commissioned research, and consideration of a range of other reviews and studies. In addition, this work was informed by consultations with stakeholders between July and November 2013 and by consideration of a number of confidential submissions. The study has also benefited from the views of members of the Industry Reference Group, a high-level group comprising of representatives from the upstream supply, infrastructure/distribution and end-user segments of the gas market. The Department of Industry and BREE acknowledge and thank stakeholders for their positive engagement with this work.

Given the limited transparency in the eastern Australian gas market, it is increasingly apparent that no single participant has a comprehensive picture of gas reserves and transactions within the market. This highlights the problem faced by market participants and policymakers in this area. In this context, this study aims to present a credible picture of often conflicting information in the eastern Australian gas market. Where information is critical to policy conclusions but is lacking, the report identifies alternative paths to close information gaps. Accordingly, the data and observations provided in this report should be used as a guide only.

This report gives a picture of the market at a particular point in time, but reflects an evolving understanding of the complexities of the gas market by the Department of Industry and BREE. Given the dynamic nature of the market, the Department and BREE will continue ongoing analysis in this area to inform the debate.

Terms of reference

Study on the Eastern Australian Domestic Gas Market

Background

Australian gas markets are undergoing a significant period of development. In particular, the eastern Australian gas market is undergoing a period of substantial transformation, with the development of Coal Seam Gas (CSG) and the associated creation of an east coast Liquefied Natural Gas (LNG) export industry.

Once the LNG plants come into operation (expected from 2014) there will be a massive increase in demand for gas in the eastern Australian market, with total demand forecast to rise from 697 petajoules per annum (PJ/a) in 2012 to 1395 PJ/a in 2015 and 2386 PJ/a in 2020 (Gas Statement of Opportunities 2012). The Commonwealth's National Energy Security Assessment and follow up consultation with industry indicated that this increase in demand could lead to a period of tightening between the demand for and the supply of gas from around 2015.

While the LNG industry is helping to expand Australia's gas market by bringing on new gas supplies and greater pipeline infrastructure, the timing of these activities and the increasing exposure to international markets is creating considerable uncertainty in relation to the availability and cost of domestic gas. Specific uncertainties include the extent, duration and significance of any potential tightness in gas supply in the eastern market in the critical period between 2015 and 2020 and how any tightness will manifest itself, in particular the degree of contracting risk faced by consumers.

Current information on the gas market is limited, with information gaps around forecast domestic supply of gas, particularly given the commercial sensitivities. Some major industrial users of gas have reported they are unable to secure domestic gas supply contracts during this period at any price. Others are reporting being offered short term contracts at much higher prices than existing contracts. While many gas producers are reporting that they are willing to sign gas contracts but it is a question of price and term. There is also limited information about the relationship between international and domestic supply conditions and pricing and how this interaction will play out over time.

This Study will help address this information asymmetry and inform Government's decision making with respect to effective resource management and development of both the domestic and LNG market. Specifically, the Study aims to provide analysis of the expected gas demand-supply situation and identify potential constraints on domestic supply availability over the period 2015–2020 and its consequences for the price of gas. International linkages will also be considered.

Gas Market Study Objective

The Study will be a joint project between the Department of Resources, Energy and Tourism and the Bureau of Resource and Energy Economics. The objective of the Study is to produce a comprehensive report on Australia's gas markets, the state of play and barriers to domestic gas supply, focusing on eastern Australia but including analysis of the operation of the West Australian gas market. It is intended to provide a comprehensive view of the level of activity and competitive structure within the domestic supply industry covering tenement holders, upstream producers, pipeline owners/managers and shippers. It will also seek to estimate the current level of demand, price for gas and volumes of both short and long-term gas contracts. Importantly, it will also explicitly consider linkages between these domestic gas market variables and international markets and thereby facilitate exploration of the impact on the domestic gas market of alternative international market scenarios.

The Study will utilise a scenario approach to identifying market trends over the period 2013–2023, to provide a clear picture of the demand-supply situation in the eastern Australian gas market over the 10 year period with a particular emphasis on the period of 2015–2020.

In addition, the Study will seek to identify the potential constraints on domestic supply availability. This may include physical barriers (eg pipeline constraints) or non-physical (eg regulatory barriers) and the implications of competition with international gas demand and supply. An array of potential policy responses to mitigate any identified constraints and options to assist in improving the market dynamics to respond to emerging price signals will also be considered.

Study Scope

Building on an understanding of the developments in Australia's gas markets over the previous two decades, the Study will include scenarios over the time period 2013–2023 drawing on the following data:

- gas reserves;

- gas production rates;

- gas market demand (including but not limited to short and long-term gas contracts);

- pipeline capacity;

- wholesale and retail gas market prices; and

- state and federal government regulatory and policy settings regarding gas field developments.

As the supply and demand dynamics of the eastern gas market are interlinked with the export LNG market, the Study and scenarios will consider market trends for the international gas market, especially in the Asia-Pacific region.

The scenario-based Study will also need to account for the following market conditions:

- general macroeconomic environment;

- LNG project developments;

- conventional, shale, tight and CSG gas development and production rates; and

- gas market infrastructure developments.

Stakeholders and Consultation

It is proposed an industry reference group be set up comprising relevant stakeholders, particularly gas users and producers, to put their views, experience and expectations about the development of Australia's gas markets forward. Other Commonwealth agencies and state and territories governments will be kept informed throughout the project's development.

Timing

The project is expected to commence mid 2013 with a final report to be completed by the end of 2013. The report would be made public by the Minister for Resources and Energy in consultation with the Prime Minister.

Released 27 May 2013

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1. Introduction

In 2011, the International Energy Agency (IEA) posed the question "Are entering a golden age of gas?" The IEA put forward a scenario with a high growth trajectory for gas where gas overtakes coal as the world's major energy source by around 2030. Demand in non-OECD countries (particularly China, India and Middle East countries) drive the increase in world gas consumption. The gas-fired power sector would be the major driver of demand growth in these economies, and unconventional gas sources would play an increasingly important role in meeting that demand. In exporting economies such as Australia, there would be benefits from rapid investment in exploration, development and infrastructure, job creation and new sources of export revenue.

While the IEA's latest *World Energy Outlook* stepped back slightly from that strong growth story, gas continues to be forecast as a growing global energy source and Australia is predicted to become an increasingly important energy supplier to the Asia–Pacific region. Rapid and large-scale investment in liquefied natural gas (LNG) production capacity is readily observable in Australia and has had economy-wide implications. However, the scale of the industry is often underappreciated.

Australian gas currently supports three operating LNG projects: the North West Shelf Venture, with five LNG trains (liquefaction and purification units), and single trains at both the Darwin LNG project (with gas from the Joint Petroleum Development Area with East Timor) and the newest project at Pluto (Western Australia). The Bureau of Resources and Energy Economics (BREE 2013) expected LNG exports in 2012–13 to be just over 24 million tonnes and worth nearly $14.5 billion in export income. In 2017–18, BREE forecasts exports to exceed 80 million tonnes and be worth just over $60 billion. The scale of investment to achieve these projections is unprecedented – seven new projects and 14 trains in construction, comprising over $180 billion in committed capital.

The current development of three (potentially four) LNG export projects near Gladstone in Queensland is significantly transforming the eastern gas market. The LNG projects have ambitious timetables, around four years from project sanction to completion, and are expected to commence operations from 2014 (Table 1.1).

LNG capacity on the east coast of Australia is being built on the back of gas discoveries in Queensland coal basins. Coal seam gas (CSG) is changing the dynamics of eastern Australia's energy markets and bringing substantial economic benefits to Australia. In Queensland, those benefits include over $63 billion in direct investment into LNG and the creation of almost 30,000 jobs during the current construction phase (APPEA 2013) and up to 17,000 direct and contractor jobs when projects reach full production after 2020 (Energy Skills Queensland 2013). Even as the boom in construction activity in Gladstone subsides over the medium term, continuing CSG production activity supported by ongoing exploration, appraisal and development will maintain a flow of economic benefits in regional Australia.

Table 1.1: Major Queensland LNG projects

Under construction	Owner/proponent	Capacity (Mtpa)	LNG trains	Cost (A$b)	Estimated completion date
Australia Pacific LNG	Origin Energy (37.5%) ConocoPhillips (37.5%) Sinopec (25%)	9	2	24.7	2015
Queensland Curtis LNG	BG Group (73.75%) CNOOC (25%) Tokyo Gas (1.25%)	8.5	2	US 20.4	2014
Gladstone LNG	Santos (30%) PETRONAS (27.5%) Total (27.5%) KOGAS (15%)	7.8	2	US 18.5	2015
Planned					
Arrow LNG	Shell (50%) PetroChina (50%)	8	2	na	2017+

Source: BREE and Company reports

However, the rapid transition of the eastern market from an isolated and self-sufficient market to one linked to high-value international gas markets has also brought challenges. No country has developed an LNG export industry based on CSG, and only Qatar has experienced a similar speed and scale of export capacity expansion. The Australian CSG experience differs from the development and production of shale gas in the United States. CSG production in Australia does not include the valuable co-produced natural gas liquids that contributed heavily to the considerable expansion of gas production in the United States and the subsequent reduction in the price of gas.

Production in the eastern market will need to increase from the current level of over 700 petajoules (PJ) to nearly 2,300 PJ by 2016 to meet forecast domestic market and LNG export demand from the three LNG projects in construction. Many domestic long-term contracts will expire during that period, and replacement sources of supply will need to be secured. It is therefore not surprising that a critical source of uncertainty in the market is whether the new CSG resources will be produced in time to meet LNG train commissioning schedules and contractual commitments and what impact this will have for domestic customers.

1.1 Foundations of uncertainty

The gas market's structure has evolved incrementally and has been supported by timely investment in infrastructure. The structure is characterised by a limited number of major upstream players to leverage economies of scale. There is some basin-on-basin and project competition on the supply side, the effectiveness of which is being tested during this transition period.

While the 'golden age of gas' and the strong international LNG market present a story of opportunity and export demand, major domestic gas users and retailers are facing significant uncertainty about the availability and price of gas. Prices were always going to rise in the face of increasing production costs, but how far is increasingly difficult to predict in the face of diverging expectations on price and uncertainty about the supply response. The large number of long-term contracts rolling off during this transition period and offers of shorter term contracts compound the uncertainty for major domestic gas users.

Major gas users face an inevitable increase in the cost of gas, which will create particular challenges for companies already wrestling with productivity, a strong dollar and import competition. A number of gas users have indicated that they are investigating alternative energy sources or considering discontinuing gas-intensive operations.

The domestic market's ability to deliver efficient outcomes in a period of rapid change is untested and the subject of debate. While many stakeholders say they are satisfied with the bilateral contract market that has characterised trade in gas in Australia to date, there is a growing debate about the adequacy of current arrangements as we move to an export-linked and more dynamic gas market.

Underlying this already difficult commercial environment are diverging views of critical price drivers. These uncertainties include:

- how quickly CSG can be delivered to meet export requirements and the increasing costs of developing gas resources

- the size of the future opportunity in international markets (particularly the potential for additional LNG trains in eastern Australia over the forecast period)

- whether opportunities exist to exercise market power and reallocate risk from export projects to the domestic market and the impact of sustained high gas prices on demand

- infrastructure constraints that potentially create barriers to entry for new gas supplies.

Given these uncertainties, there are questions about how well the gas market will adjust to the new conditions in the presence of massive and rapid change and the possibility of transitional supply tightness. There are also questions about unconventional resource development, a lack of price transparency, and limited liquidity and depth on both the supply and demand sides. It is unlikely that these uncertainties will be fully resolved until the CSG–LNG projects reach a stable production stage.

1.2 Production and exports – timing is everything

Since the late 1970s, domestic gas production in eastern Australia has been a story of steady growth in an environment of relatively low gas prices. The onshore Cooper Basin and the offshore Gippsland Basin dominated production until 2002, when Cooper Basin production began to decline. In its place, CSG production dramatically increased from 2006, aided by Queensland Government policy to mandate a level of gas-fired electricity generation. In 2010, BG Group took a final investment decision on the first CSG–LNG project, accelerating the linkage to international prices.

The current development of LNG in eastern Australia and the expected tripling of gas demand are creating conditions that are in stark contrast to those in the previously isolated domestic gas market. The timely development of gas resources will be important to ensure that supply is available for domestic gas users and to meet LNG export commitments. Such is the scale of the LNG projects that even small deviations from the CSG reserve development schedule could result in significant volumes of gas being sourced from traditional domestic market supplies (Figure 1.1).

A critical issue for all market participants is uncertainty about the match between train commencement and CSG production, including the number and performance of CSG wells. If additional trains are constructed either within the three current projects or as new projects, the additional demand has the potential to compound these issues.

Figure 1.1: Potential growth in the eastern Australian gas market
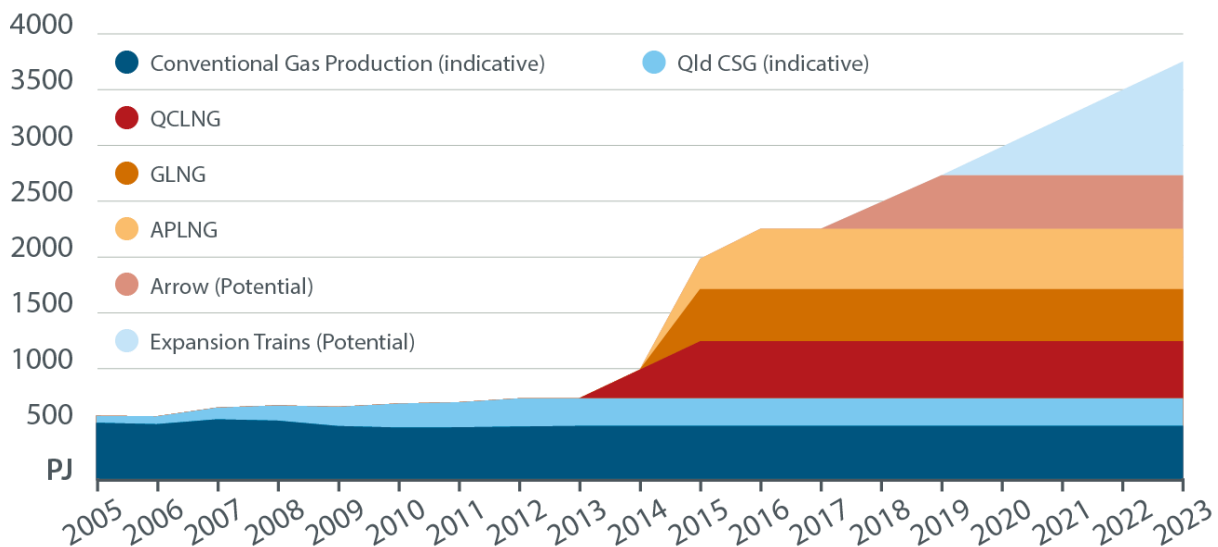
Note: Assumes constant forward domestic demand for illustrative purposes.
Source: EnergyQuest (2013) and company reports.

While the reserves of the Surat and Bowen coal basins are of particular importance to the LNG sector and currently supply the overwhelming majority of CSG to the domestic market, other basins, including the Galilee and Cooper–Eromanga basins, also have potential for CSG and for shale gas, which is in the early stages of exploration and appraisal. The Gunnedah, Gloucester, Sydney and Clarence–Morton basins all have the potential to be important contributors, especially for New South Wales domestic gas users. There is also potential to develop new conventional gas fields and increase production from existing conventional gas fields in the Cooper–Eromanga, Gippsland, Otway and Bass basins. As some of these basins are in greenfield locations, additional infrastructure will be needed to underpin and facilitate future investments in these new sources of supply.

These issues are considered further in Chapters 2 and 3.

1.3 Domestic market infrastructure

Infrastructure has implications for competitive outcomes in the eastern gas market, but there is little public information about how processing, storage or pipeline capacity is being utilised and under what terms.

Processing infrastructure in the eastern market is dominated by two plants (Longford in Victoria and Moomba in South Australia), which provide a significant proportion of the overall capacity. Both plants are undergoing major developments to enable them to handle additional volumes and to cope with more challenging gas compositions. As new developments occur, particularly in the Cooper–Eromanga Basin, access to new and existing processing infrastructure will be important for the economic production of new gas resources.

There are limited storage options serving the eastern market. New domestic LNG storage and depleted gas reservoir storage will both be increasingly important in a supply-constrained domestic market where peak demand periods may challenge the network's capacity. The LNG export projects are driving an expansion of gas storage as part of their supply-side management.

The market is serviced by a network of transmission pipelines, which connect gas basins with metropolitan demand centres, electricity generators and industry. There has been extensive investment in pipelines in the past 20 years, including in the construction of the South West Queensland, Carpentaria, Eastern Gas, Tasmanian Gas and SEA Gas pipelines and in increasing the capacity of others, including the Roma to Brisbane and South West Queensland pipelines. The ownership of this capacity is becoming increasingly concentrated.

The traditional business model for Australian pipeline operators is based on long-term gas transportation agreements with gas shippers, who effectively underwrite the construction of new pipelines and pipeline expansions. This traditional business model minimises risk for the pipeline owners - and it would be rare for a pipeline owner to expand pipeline capacity or construct a new pipeline without at least one long-term contract to underwrite the considerable capital investment.

While some of the market's pipeline capacity is congested during peak demand periods, investment in infrastructure has responded well to market signals. A reasonable expectation would be that any obvious bottlenecks could be eased by relatively modest and market-led infrastructure investments. The implications of uncertainty and shorter term contracting for these market signals, and whether there are further opportunities to facilitate more efficient trading of unused capacity, may need further consideration.

These issues are considered further in Chapter 4.

1.4 Market structure and operation

The capital-intensive nature of gas supply and transmission infrastructure combined with a desire for long-term supply certainty from major gas users, has seen the development of a bilateral contract market as the preferred vehicle to best manage long-term risks. These bilateral contracts are in the form of gas transportation agreements (GTAs) between pipeline operators and shippers and gas supply agreements (GSAs) between gas producers and gas buyers.

These contractual arrangements usually contain a complex array of terms, conditions and price linkages, but are opaque to third parties. Knowledge of contract terms and prices is largely based on informal mechanisms within the small gas trading community.

This lack of market transparency regarding contract information may limit the ability of some participants to negotiate confidently on price, producing disproportionately high transaction costs for smaller volume trades. A lack of information may also limit the development of the gas market and related forward markets and products that could help market participants manage their commercial risks.

While progressive reforms have led to important incremental changes to the market, the ability of the market to deliver efficient outcomes under the pressure of the current rapid transition is being tested. Recent reforms have promoted a modest degree of transparency and price discovery through the small volumes traded in the short-term trading markets of Adelaide, Sydney and Brisbane and the Victorian Declared Wholesale Gas Market. A further gas supply hub is also being developed at Wallumbilla in Queensland.

These issues are considered further in Chapter 5.

1.5 Potential policy problems and options

The eastern gas market is in transition from being an isolated, relatively stable and low-priced market to being linked to international gas markets where prices are higher. Domestic gas prices are adjusting accordingly. Historically, demand for gas has grown modestly, primarily in response to investment in gas-powered generation, however LNG exports will see an unprecedented demand for gas.

The problem facing the eastern gas market is that the transition to LNG exports and the uncertainty on gas supplies have not yet been resolved, so the basis for gas prices and the nature of the future supply response remain unclear.

Gas in the eastern market has been supplied mainly from conventional gas fields, which in many cases have low reserves remaining. However, recent innovations in drilling techniques and technologies have opened up a major new source of supply in the form of CSG. The realisation of the magnitude of the potential supply of CSG coincided with a period of strong demand for LNG from Asian customers.

Major energy companies saw these market developments as an opportunity to enter the LNG export market using (for the first time anywhere in world) CSG reserves to feed LNG trains. When the LNG projects were commissioned, there was a general belief that the feedstock gas required by the proposed LNG trains could and would be supplied entirely from new CSG reserves. There was also a belief in the domestic market that a surplus of gas would be available before the trains ramped-up to full LNG production and that, as a result, the price of gas would be low during that period. This has proved not to be the case and has affected the long-term contracting strategies of some market participants.

The difficulty facing the market is that gas is being produced from an unconventional resource where production over time has some uncertainties. This makes it challenging to form a view of CSG availability and reliability for both the export projects and domestic demand and hence the extent to which gas from conventional sources may also be needed to augment supply for LNG production.

The scale of this uncertainty has implications for both the availability of gas for domestic consumption and the size of gas price rises. This may have made suppliers cautious about committing to material volumes to the domestic market until the uncertainty is resolved.

This is not to say that parties operating in the market during this transition period are doing so improperly. In an environment characterised by rising wholesale gas prices and supply uncertainties, there may be a commercial incentive to hold off negotiating and committing to long-term contracts. However, the lack of clear market signals and asymmetric information between suppliers and consumers during the transition are major issues for gas users.

In any market, a rising price is not in itself a policy problem. By extension, there must also be an acceptance of the inevitability of some adjustment in response to price rises. However, there is debate about the efficiency of current and expected market outcomes and the form and severity of any adjustment.

It is understandable that the potential rapid adjustment to new prices is of significant concern to certain stakeholders, particularly large industrial gas users. This adjustment may also be exacerbated by, and difficult to separate from, other influences (such as the high Australian dollar and increasing project costs) on industry competitiveness.

The response to these market changes may also lead to outcomes that have implications for other policy objectives; for example, diverting gas from electricity generation may have implications for greenhouse gas emissions. While these are important matters, they are beyond the terms of reference for this study.

The current structure of the gas market is inherited from the time when there were different risks and dynamics and is essentially fixed during the most uncertain phase of this transition. It can take time to change market structures in response to new market conditions. How much this will increase the cost of transition is difficult to test. However, well-functioning markets are an important mechanism for ensuring the costs of adjustment are not greater than they need to be.

The Department of Industry and BREE are confident that the eastern market will continue to meet the medium-term and longer-run needs of participants and provide signals to support the timely supply of gas. However, governments could consider pursuing a number of measures to further improve supply, market signals, and support efficient market operation.

The focus of this study is therefore to seek an understanding of the issues in play in the gas market. The study explores a range of policy options aimed at removing impediments to supply and improving market responsiveness that could help smooth the current period of adjustment without unnecessarily increasing costs for market participants or leading to perverse market outcomes.

The nature of the policy problem and potential policy options are considered in more detail in Chapter 7.

2. Upstream supply and production

2.1 Overview

The outlook for supply and production is critical for supporting investment decisions. However, divergent expectations about the size of gas resources and when gas will be brought to market are generating significant uncertainty. This chapter considers these underlying resource and timing issues and identifies potential constraints that may be limiting the development of additional supply to meet both LNG export commitments and domestic market requirements. In the eastern market, questions about current and future gas supplies associated with the advent of LNG exports in Queensland include the following:

- Are there sufficient gas reserves and resources in eastern Australia to meet long-term LNG production and domestic gas supply requirements?
- Can new CSG reserves be developed and produced in a timely manner consistent with LNG contract requirements without additional draw from the domestic market?
- What are the costs of new supply development?
- Are there barriers or constraints that may be preventing the development of gas reserves and resources?

By its nature, energy resource exploration is an uncertain business that requires interpretation, extrapolation and analysis to understand the targeted geology and potential hydrocarbon reservoirs. Turning a resource that is speculative and prospective into a firm reserve that will underpin a gas development is a major investment requiring time, capital and technology.

Box 2.1: Definitions of gas reserves and resources

Reserves and resources are not static estimates of gas in the ground but figures at a given point in time. Those figures may increase or decrease, depending on geological understanding and the commercial and technical drivers for gas projects. The Australian Securities Exchange (ASX) mandates standards for the public reporting of petroleum resources by Australian-listed companies

Proved and probable (2P) reserves are widely quoted as those needed to underpin projects such as the CSG–LNG projects being developed in eastern Australia. They are a relatively bankable estimate of potential gas available for production over the life of a project.

Contingent (2C) resources are estimates of gas resources at a given date that may be recoverable from known gas accumulations, but commercial projects to develop those resources have not been established because of technical, regulatory or commercial challenges. If these challenges are addressed, contingent resources may transition to the reserves category and be available for development; however there is no guarantee a contingent resource will ever be recoverable.

Finally, there are substantial prospective resources that have been inferred as being in place from comparisons of the geological understanding of particular petroleum basins. These estimates may be very high and may change considerably as they are firmed up by exploration and appraisal.

2.2 Sufficient gas reserves

Gas is Australia's third largest energy resource after coal and uranium. Just over half of the nation's gas resources are in offshore basins along the north-west margin (Figure 2.1). Some of the youngest petroleum reservoirs (Late Cretaceous to Paleogene sandstones) are offshore Victoria in the Gippsland, Bass and Otway basins, while onshore are some of the oldest (Permian sandstones) in the Cooper Basin. Large CSG resources exist in the coal basins across eastern Australia.

Figure 2.1: Locations of Australia's gas resources and two potential gas basins
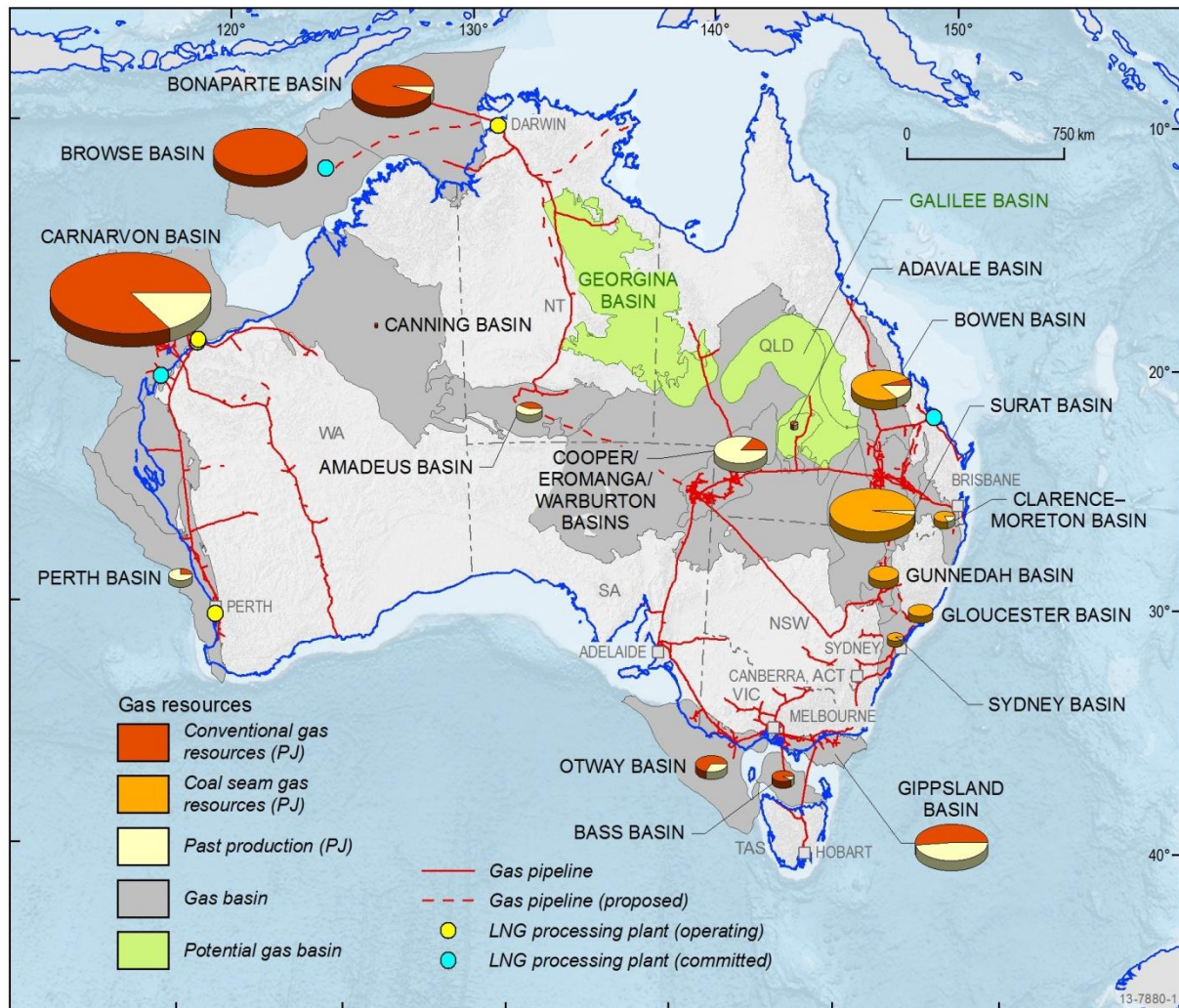
Source: Modified from GA and BREE (2012).

There is consensus that Australia has sufficient gas resources to meet both domestic and export needs. This includes gas resources for the eastern market, where the three LNG projects in construction, a fourth potential project (either as a stand-alone or integrated with other projects) and the domestic market (at current levels) will require around 2,000-3,000 PJ per year in gas supply. This equates to around 40,000–50,000 PJ in proved and probable (2P) reserves to effectively underwrite 20 years of secure gas supply. Australia's 2P reserves are currently within that range, and contingent resources and further exploration and appraisal have the potential to rapidly exceed it.

In particular, as the CSG–LNG projects complete the first round of development drilling, they will refocus their exploration and appraisal activities to increase 2P reserves. Additional 2P reserves are also likely to be available for development in the Cooper–Eromanga basins as current exploration and appraisal drilling resolves many of the geological and technical uncertainties associated with resources in those basins.

According to the *Australian Gas Resource Assessment 2012* (AGRA; GA and BREE 2012)*,* eastern Australia has over 44,000 PJ of 2P gas reserves, most of which are CSG reserves in the Surat and Bowen basins. Research prepared for this study by Resource and Land Management Services (RLMS 2013) reports a higher figure of just over 50,000 PJ of 2P reserves. Both AGRA and RLMS attribute substantial additional contingent (2C) resources for eastern Australia.

Table 2.1: Total eastern Australian 2P gas reserves and 2C gas resources

Basin and hydrocarbon	2P reserves (PJ)		2C resources (PJ)	
	AGRA (2012)[a]	RLMS (2013)[b]	AGRA (2012)[a]	RLMS (2013)[b]
Conventional gas - *Offshore Victoria*				
Gippsland Basin	5,428	3,890	3,880	1,094
Otway Basin	1,025	720	535	116
Bass Basin	261	245	508	360
Onshore South Australia/Queensland				
Cooper/Eromanga/Warburton basins	1,056	1,835	125	4,968
Surat/Bowen/Adavale basins	554	161	6	0
Onshore New South Wales				
Gunnedah Basin	12	–	–	–
Clarence–Morton basins	–	–	80	–
Total conventional gas	***8,336***	***6,851***	***5,134***	***6,538***
Coal seam gas				
Queensland				
Surat/Bowen basins	33,001	41,620	–	25,024
Galilee Basin	–	–	–	316
New South Wales				
Gunnedah Basin	1,520	1,426	–	3,460
Clarence–Morton basins[c]	428	445	–	2,511
Gloucester Basin	669	669	–	–
Sydney Basin	287	282	–	542
Total New South Wales CSG	*2,904*	*2,822*	–	*6,513*

Basin and hydrocarbon	2P reserves (PJ)		2C resources (PJ)	
	AGRA (2012)[a]	RLMS (2013)[b]	AGRA (2012)[a]	RLMS (2013)[b]
Total CSG	*35,905*	*44,442*	*65,529*[d]	*31,853*
Shale/tight gas				
Cooper Basin	~3[e]	–	2,200[f]	4,240
Total gas	**44,244**	**51,293**	**72,863**	**42,631**

a   As at 1 January 2011, reported in AGRA 2012 (GA and BREE 2012) from GA (2012) and DNRM (2012).

b   As at 31 December 2012, from RLMS (2013).

c   AGL have revised down reserve and resource assessments for Gloucester and Sydney basin in 2013 Annual Report.

d   2C resources at 30 June 2012 used as a proxy for sub-economic resources in AGRA 2012 (GA and BREE 2012).

e   2P shale gas reserve booked by Santos from the Moomba 191 well in 2012.

f   2C shale gas contingent resources reported by Beach Energy from the Cooper Basin in 2011 and conveyed in AGRA 2012 (GA and BREE 2012). Beach Energy revised the 2C unconventional gas resources in the Cooper Basin at 30 June 2012 to 1,895 PJ. Figure does not include the 2,345 PJ of 2C resources from a variety of unconventional sources (shale gas, tight gas, mixed lithologies and deep coals) reported by Santos from the Cooper Basin in late 2012.

2.2.1 Conventional gas

Eastern Australian 2P conventional gas reserves are almost entirely sourced from the offshore Victoria Gippsland and Otway basins and the inland Cooper–Eromanga basins. The offshore Gippsland Basin still has significant reserves after more than 40 years of production. The Cooper–Eromanga basins have been producing gas for over 35 years and their conventional gas reserves are declining. All conventional gas reserves in eastern Australia are currently directed solely to domestic consumption.

Comprehensive and up-to-date estimates of uncontracted and/or uncommitted 2P reserves are difficult to compile because most gas contract volume data is not obtainable. Core Energy (2013) reported that at 31 December 2012 approximately 52 per cent of 2P conventional gas reserves (3,661 PJ) in eastern Australia were uncommitted and available to the domestic market. About 68 per cent of that volume (2,499 PJ) is sourced from the Gippsland Basin and another 21 per cent (777 PJ) from the Cooper–Eromanga basins. Santos (2013) has announced that it has significant uncommitted 2P reserves of around 870 PJ in the Cooper–Eromanga basins.

2.2.2 CSG

Proved and probable CSG reserves are now approximately four to seven times larger than conventional gas reserves; 2C CSG resources are up to 12 times larger than conventional gas 2C resources.

AGRA 2012 (GA and BREE 2012) reported around 36,000 PJ of 2P reserves and up to 66,000 PJ of 2C resources of CSG in eastern Australia (Table 2.1). The CSG reserves are in seven basins across central and south-east Australia, and about 90 per cent of the 2P CSG reserves are in the onshore Surat and Bowen basins in Queensland. Most are held by the CSG–LNG projects as shown in Table 2.2. Core Energy (2013) has estimated that around 80 per cent of the 2P reserves in the Surat and Bowen basins are committed, mainly to the LNG projects.

Table 2.2: CSG reserves and resources for the eastern Australian LNG projects

LNG project (trains)	Capacity (Mt/year)	Reserves (PJ)			Contingent resources (PJ)
		1P	2P	3P	2C
Australia Pacific LNG (2 trains)	9	1,527	13,349	16,110	3,644
Queensland Curtis LNG (2 trains)	8.5	3,047	10,518	11,397	4,508
Gladstone LNG (2 trains)	7.8	1,797	5,376	6,823	1,638
Arrow LNG (2 trains)[a]	8	551	8,251	12,792	2,521
Total LNG projects	**33.3**	**6,922**	**37,494**	**47,122**	**12,311**

a   Arrow LNG is yet to take a final investment decision and is not yet in construction
Source: EnergyQuest (2013b).

Of the remaining 2P CSG reserves, approximately 50 per cent is in the onshore New South Wales Gunnedah Basin and smaller amounts are in the Gloucester, Clarence–Moreton and Sydney basins. There are a number of companies actively exploring for other CSG sources in onshore Queensland, New South Wales and South Australian basins.

2.2.3 Other unconventional gas

In the 10-year forecast timeframe for this study, other types of unconventional gas (shale gas, tight gas, deep CSG) are not expected to alter the market outlook significantly. Nevertheless, the timely development of these resources is likely to be a feature of the market dynamic in future years. While a lack of knowledge about the resources and the cost of exploration and development (drilling equipment, pipelines, roads, processing facilities and labour) may impose limits on the speed at which these resources will be brought into production, the surprisingly rapid development of CSG (driven by LNG production) may translate to other unconventional gas sources. Experience of the United States suggests that the economics of unconventional gas development will be considerably enhanced if resources include petroleum liquids (shale oil).

Currently, eastern Australia has no tight gas that can be technically classified as reserves. However, inferred resources of tight gas in central and south-eastern Australia are estimated at around 10,643 PJ. Ongoing exploration activity suggests that this figure is likely to grow, especially in established conventional gas-producing basins with access to established infrastructure. The largest known resources of tight gas in eastern Australia are in low-permeability sandstone reservoirs in the Cooper and Gippsland basins. Currently, about 8,800 PJ (8 tcf) of tight gas is estimated in the Cooper Basin (Campbell 2009), and around 1,853 PJ (2 tcf) in the Gippsland Basin (Lakes Oil 2011).

The definition of shale gas reserves and resources in Australia is at an early stage of understanding but is most advanced in eastern Australia. In 2011, the first contingent shale gas resources were reported by Beach Energy in the Cooper Basin (assessed as 1,895 PJ in 2012). Santos booked the first (albeit small) Australian 2P shale gas reserves in the Cooper Basin in 2012 and an estimated 2,345 PJ of 2C contingent resources in the basin from a variety of unconventional sources (shale gas, tight gas, and deep coals) that potentially overlap conventional resources.

A number of other companies are actively exploring for other unconventional gases in the Cooper–Eromanga basins and other areas, including Senex, Drillsearch and Exoma. Strike Energy is targeting deeper CSG in the Cooper Basin, and QGC is targeting deeper tight sands underneath its permits in the Surat Basin. Blue Energy is currently evaluating the potential of shale gas in the Georgina Basin in north-western Queensland.

The recent Australian Council of Learned Academies report on unconventional gas production estimates (Cook et al. 2013) suggested that potentially recoverable shale gas resources may be as high as 290,000 PJ (274 tcf) in eight basins in central and south-east Australia. The Cooper–Eromanga basins are where most exploration and appraisal activity is currently taking place and may have 123,000 PJ (117 tcf) of dry gas and 15,000 PJ (14 tcf) of wet gas. However, there is uncertainty attached to initial estimates of shale gas resources that are based on limited data and little production history. While exploration activity has significantly increased in the past few years, the resource potential in this area will become clearer with further exploration and appraisal.

2.3 Development and production

The critical issue for confidence in supply for the domestic gas market is the rate at which the gas reserves in eastern Australia can be developed and brought into production and the level of uncertainty in those production rates.

Conventional gas from the onshore Cooper–Eromanga basins and the offshore Gippsland Basin – led by the Gippsland Joint Venture of Esso (ExxonMobil) and BHP Billiton – has historically supplied most of eastern Australia's gas requirements. Conventional gas production from the Cooper–Eromanga basins peaked from about 1999 to 2002 and then began a decline, while production from the Gippsland Basin was relatively steady during that period at between 200 PJ and 260 PJ per year.

As the decline in gas production from the Cooper–Eromanga basins commenced, a 250 PJ per year capacity pipeline from Papua New Guinea was proposed as the replacement option for that gas. However, CSG in Queensland, which had begun commercial production from 1996, was being more intensively investigated through this period, and in 2005 the Queensland Government introduced a 13 per cent gas-fired generation target to stimulate the gas industry. The growth in CSG production in conjunction with new Otway Basin conventional gas production effectively offset the declines from the Cooper–Eromanga basins and met new demand in eastern Australia, and the idea of gas from Papua New Guinea became redundant.

Figure 2.2: Eastern Australian gas production, 1994 to 2013 (PJ per year)
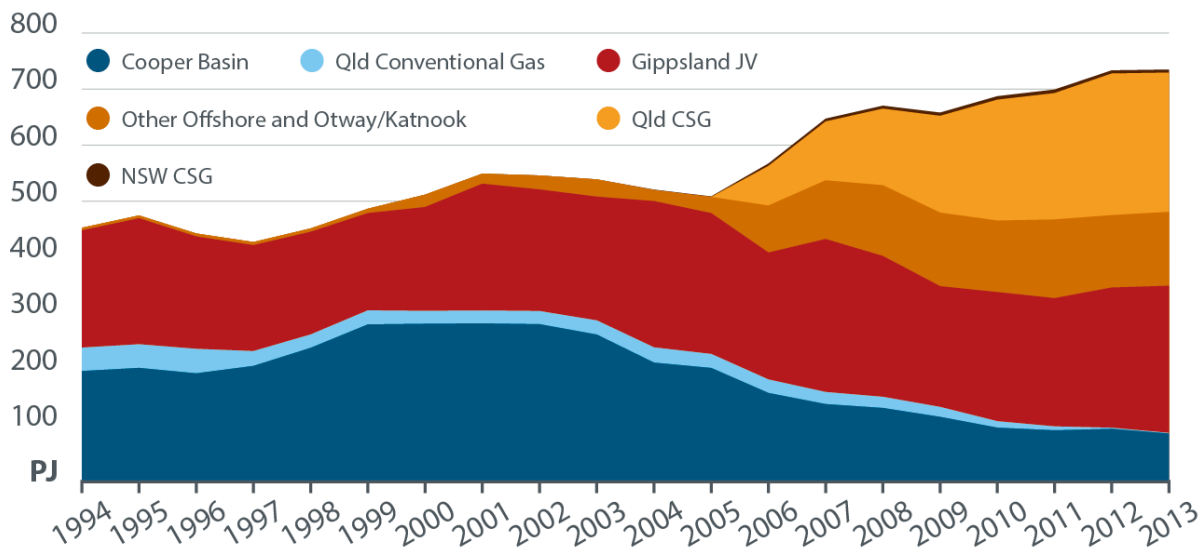
Source: APPEA statistics and EnergyQuest (2013b).

By 2007, the CSG resource was being seen as potentially much larger than required solely for the domestic market. A rapid rise in exploration and production coincided with the first announcements of acquisitions within the CSG industry as large multinational oil and gas companies moved to bring LNG production to the east coast. BG Group, Total, PETRONAS, ConocoPhillips and Shell joined Australian companies Santos and Origin, along with major customers such as Kogas, PetroChina, CNOOC, Sinopec and Japanese utilities, in taking interests in the industry.

In October 2010, BG Group's QCLNG Project was the first LNG project to reach its final investment decision, followed by GLNG (Santos, Total, PETRONAS and Kogas) and then APLNG (Origin Energy, ConocoPhillips and later Sinopec). The Arrow LNG Project (Shell and Petro China) is yet to make its final investment decision.

Eastern Australia produced over 700 PJ of gas in 2012–13, almost half of which was sourced from the conventional gas fields of the offshore Victorian Gippsland and Otway basins. Around one-third of gas production was from CSG in the Surat and Bowen basins in Queensland, and most of the remainder was sourced from the Cooper–Eromanga basins. A small amount of that production was placed into storage.

If market conditions prove attractive and parties agree, some production facilities have the potential to increase production from conventional gas fields. In May 2013, Santos announced that it will increase gas production from the Cooper-Eromanga basins by 2015.

Current production will need to more than triple to nearly 2,300 PJ by 2016 to supply both the domestic market (at current levels) and the LNG export market (the three LNG projects in construction). If the Arrow LNG Project proceeds with an additional two trains (either stand-alone or as expansion trains on existing projects), that would add an additional 480 PJ of gas production per year.

2.4 How long will gas production continue?

The cumulative production of conventional gas in eastern Australia is substantial. At 1 January 2011, approximately 6,791 PJ of conventional gas had been produced from the Cooper–Eromanga basins and only about 12 per cent of the total demonstrated gas resource remains (Figure 2.2). In the Gippsland Basin, about half of the gas resource was produced by 1 January 2011.

The major conventional gas production basins (Gippsland, Otway and Cooper–Eromanga) have between six and 17 years of gas production from 2P reserves remaining at current rates of production (Table 2.3). A proportion of higher-cost 2C resources may be brought into production as technology and economics improve.

The contingent conventional gas resources in the Bass and Cooper-Eromanga basins would add over 20 additional years to the remaining years of conventional gas production in eastern Australia (Table 2.3). Ongoing exploration for conventional gas resources in the Cooper–Eromanga, Gippsland, Otway and Bass basins suggests that there is potential to discover further conventional gas resources in those basins and extend their productive life.

Table 2.3: Estimated depletion rates for selected basins

Basin and production rate	2P reserves (PJ)	Years of 2P reserves	2C resources (PJ)	Years of 2C resources
Gippsland Basin at 270 PJ/year	3,890	14.4	1,094	4.1
Otway Basin at 120 PJ/year	720	6.0	116	1.0
Bass Basin at 15 PJ/year	245	16.3	360	24.0
Cooper–Eromanga basins at 123 PJ/year	1,835	14.9	4,968	40.4

Source: Reserves and resources (2P and 2C) as at 31 December 2012 from RLMS (2013); annual production statistics from APPEA (2013).

Companies are continuing to explore for and develop gas resources offshore in Victoria. The Gippsland Joint Venture is currently completing the $4.5 billion Kipper/Turrum/Tuna project (gas and oil production from Tuna has begun) and commencing the Longford gas conditioning plant expansion project. Once completed, the Turrum project will provide approximately 77 PJ per year of new capacity. The Kipper component of the project will add another 30 PJ per year in production and provide continued production for the Gippsland Joint Venture.

Origin Energy and its joint venture partners are continuing to prove up additional reserves to maintain current production levels in the Otway and Bass basins with potential for further discoveries in the area. There is also the potential for the discovery of new gas (and oil) fields in non-producing and frontier basins with many areas poorly explored and the large structures untested.

Santos and others are investing in new production capacity and well development in the Cooper Basin for both conventional and unconventional gas production. Santos is upgrading the Moomba gas plant to address gas composition issues associated with some of the new gas coming on-stream. Testing on a number of wells will be carried out during 2014, along with the use of multi-well pads to improve efficiency and reduce costs.

2.4.1 CSG production

The first commercial production of CSG began in 1996 from the Bowen Basin in Queensland. CSG production in eastern Australia is now around 250 PJ (over one-third of total eastern Australian gas production) and comes almost exclusively (more than 97 per cent) from the onshore Bowen and Surat basins. The remaining three per cent is from the onshore Sydney Basin. More than 90 per cent of CSG production to the domestic market is from the four LNG project joint ventures (or companies associated with them).

CSG supplies approximately 80 per cent of the Queensland market. During 2011–12, CSG production from the Surat Basin was, for the first time, greater than production from the Bowen Basin (Figure 2.3). Production of CSG in New South Wales is from AGL's Camden Project in the Sydney Basin, which has been steadily producing roughly 5–6 PJ of gas per year since 2007.

Figure 2.3: Eastern Australia CSG production since 1996, by basin
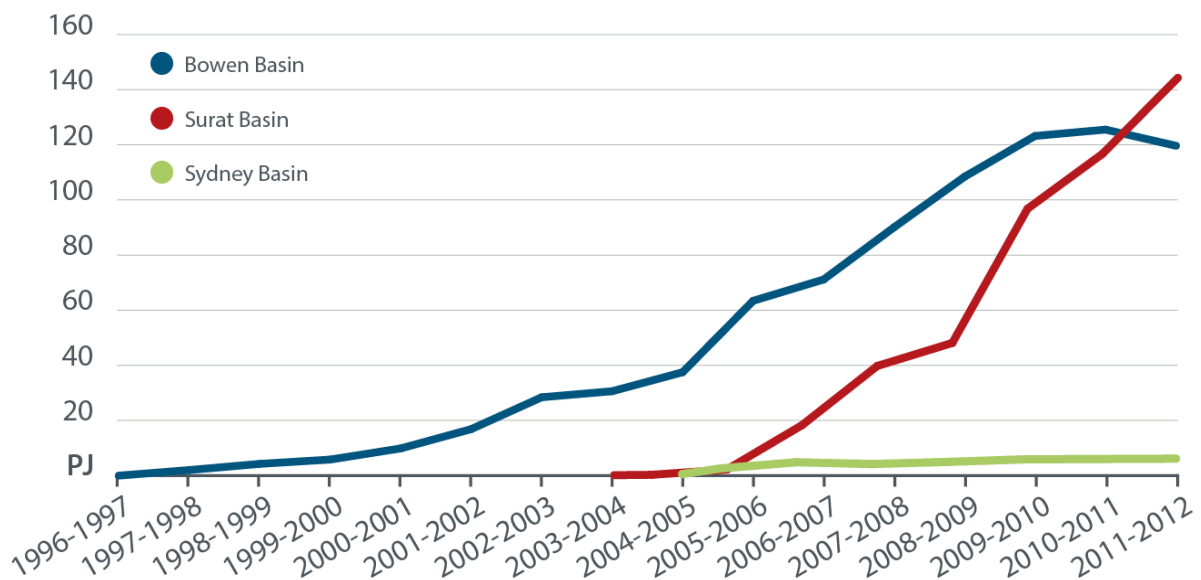
Source: Bowen and Surat basins – DNRM (2013); Sydney Basin – APPEA (2013).

Approximately 85 per cent of the 2P CSG reserves and 60 per cent of the 2C CSG resources are controlled by the four major LNG projects (including Arrow which is yet to take a final investment decision). Of the 15 per cent of reserves theoretically available for the domestic market, there are approximately 25 years of 2P reserves remaining at current annual production rates. Current contingent resources not directed solely to the four LNG projects may also become economically viable to produce and could supply an additional 32 years of CSG production in eastern Australia.

CSG production capacity is expanding rapidly to meet the LNG obligations as the six LNG trains under construction commence production. Two of the three projects under construction (GLNG and QCLNG) are also purchasing additional gas: GLNG from Santos in the Cooper Basin and Origin Energy (source not specified) and QCLNG from AGL (effectively buying back gas contracted to AGL by QGC) and APLNG. While the LNG proponents expect to continue to fulfil existing commitments to the domestic market, there may be a reluctance to offer additional gas domestically until volumes to underpin LNG contracts are assured.

Additionally, a number of small 'independent' producers are developing CSG projects. AGL is the largest, with minority interests in some production from the Surat and Bowen basins and its own project in the Galilee Basin. Westside Energy Corporation has commenced production from its project in the Bowen Basin with a number of other companies active in both the Surat–Bowen and Galilee basins. While there is scope for these companies to provide additional volumes into the domestic market as projects are developed, LNG proponents have bought out or taken over the many promising independents.

2.4.2 LNG and timely development

The three LNG projects in construction all appear to be making good progress against demanding schedules, and all report – to varying degrees of detail – that they expect to meet contractual obligations for the completion of projects and the supply of LNG. Santos (in its October 2013 quarterly activity report) noted that the GLNG project is now 65 per cent complete and on track to deliver its first LNG in 2015. In Origin Energy's September 2013 quarterly production report, the company noted that the APLNG upstream project was 50 per cent complete and the downstream component was 54 per cent complete. BG Group reported in its Q3 2013 results that it expects commissioning to commence by the start of 2014 and the first LNG deliveries to be made in the second half of 2014.

The upstream development timetables for the projects remain tight but all appear to be making progress on well and field development. QGC has reported an additional 225 wells being drilled in Q3 2013 and is on track to meet the requirement of 2,000-plus wells for project commencement. Santos has reported a further 67 development wells being spudded in Q3 2013, and the 200th well for the year spudded in early October 2013. Origin Energy has reported an additional 105 wells spudded in Q3 2013, with 448 wells drilled for APLNG Phase 1.

While the performance of these wells is unknown, the APLNG and QCLNG drilling rates appear to be on schedule. GLNG is mitigating drilling risk through contracting gas from Santos and Origin Energy (equivalent to 240 TJ per day). Table 2.4 gives an indication of the progress in wells drilled for the three LNG projects in construction and the requirements for the proposed Arrow LNG project. These are only an approximation of the number of wells required to support full LNG production – it is reasonable to expect very different production rates per well among the different projects and different areas within each project. Estimates of CSG well requirements will fluctuate with the evaluation of these development wells and actual well performance data.

Table 2.4: CSG development wells drilled for LNG projects

LNG project	Wells drilled Q2 2013	Wells drilled Q3 2013	Total wells drilled	Estimated wells – 2 trains	Additional production[c]
QCLNG	196	225	1,700	2,000 plus additional gas	50 PJ domestic gas
APLNG[a]	87	105	448	1,100	85 PJ QCLNG 110 PJ domestic gas
GLNG	56	67	380 final investment decision (~540 total)	1,000–1,400 plus Cooper Basin	40–50 PJ domestic gas
Arrow[b]				2,500	25–30 PJ – Dom Gas

a APLNG distinguishes between pre-Phase 1 drilling (domestic gas) and Phase 1 drilling (LNG). In Q2 2013, a total of 87 wells were drilled, bringing wells drilled for LNG to 343 to date.

b Arrow is yet to make a final investment decision or undertake intensive development drilling.

c Additional production includes current production for domestic market and contract to supply other LNG projects

Source: Company reports and EnergyQuest (2013b).

There is variability in well production across the Surat and Bowen basins, ranging from around 0.5 TJ/d to 2.2 TJ/d depending on the field. Some data on production for some areas of the basins has been published, but because of the variability across and between fields it is not possible to draw strong conclusions about how development programs are progressing or make firm assumptions about future well requirements.

The required gas volumes, projected drilling rates and individual well production profiles set a critical period for the LNG projects through to 2020, after the initial ramp-up period. The extent to which LNG proponents can meet ongoing and any additional demand from the domestic market is largely dependent on their certainty on production rates and well and field performance. LNG supply and export contractual obligations are expected to take precedence over domestic gas supply for the projects' investors.

The LNG proponents are adopting a number of additional strategies to manage these risks, ensuring both the efficient use of ramp gas (gas being produced as wells are de-watered in advance of optimal gas production) and the ability to supplement CSG production with other domestic gas. Examples of these strategies include:

- building physical and commercial links between LNG facilities
- contracting and swaps between the LNG proponents or with retailers
- cross-ownership and commercial links with power stations
- use of storage to manage ramp gas and start-up
- direct contracting of conventional gas
- potential form and timing of later project and train development
- potentially buying gas contracts from major industrial users.

However, uncertainties associated with drilling schedules, individual well performance (both production rates and production profiles) and the progress on production infrastructure (collection and main pipelines, water treatment and handling, central processing plants, access agreements) are a significant matter for other market participants when forming expectations about price and availability. Anecdotal evidence suggests that those expectations are very diverse, and that the difficulty in accessing timely data has created an information asymmetry that may not be resolved until the projects are operating.

Other unconventional gas development possibilities are likely to provide significant volumes of gas only if production costs decrease, rig and hydraulic fracture service availability increases and infrastructure issues (pipelines and logistics support capacity, in particular) are addressed. It is unlikely that other sources of CSG or unconventional gas will be able to supply any shortfall in the production for LNG exports before 2017.

The Cooper Basin is the most likely area for additional unconventional production given its connection to the eastern market (it has pipeline connections to Queensland, New South Wales, South Australia and Victoria). This is reflected in nearly $400 million in exploration expenditure in 2012–13. The cost of developing these resources is largely unknown and will be a significant factor in determining when they are brought to market.

2.4.3 New South Wales CSG development

CSG developments in New South Wales have the potential to supply more than half of current New South Wales domestic demand within the next five years. These developments include Santos's Narrabri CSG Project, AGL's Camden Gas Project Expansion, Metgasco's Casino Project and AGL's Gloucester CSG Project (Table 2.5).

Santos is proceeding with its exploration and appraisal program near Narrabri, having gained the necessary state and federal approvals for the first stage of the program in October 2013. However, regulatory issues may see the project delayed over the coming years. Two other CSG developments in New South Wales, AGL's Camden Gas Project Expansion and Metgasco's Casino Project, were suspended after the announcements on State Environmental Planning policy and their commencement remain uncertain.

Table 2.5: New CSG projects and expansion projects currently under development

Project	Company	Basin	Estimated start-up	New capacity (PJ/year)	Capital expenditure ($m)
Feasibility stage					
Gloucester CSG Project	AGL	Gloucester	2016	15	200
Narrabri CSG Phase 1	Santos	Gunnedah	–	~35	1,300
Stalled development (suspended)					
Casino (West Casino Gas)	Metgasco	Clarence–Moreton	–	18	0–250
Camden Gas Project (Stage 1) Expansion	AGL	Sydney	–	12	0–250
Camden Gas Project (Stage 2) Expansion	AGL	Sydney	–	–	0–250

Source: Company reports and BREE (2013a).

2.5 Appropriate regulation

Petroleum resources are in effect owned by all Australians, with legal ownership vested through governments' rights over these resources. Government assigns rights to explore for, develop and produce petroleum to companies through the release of exploration acreage and the administration of a petroleum tenure system. In return for those rights, companies are required to contribute back to government through taxes or royalties. Government therefore has an interest in the effective and efficient regulation of the upstream petroleum industry to maximise returns from industry for the benefit of the Australian community.

The aim of regulating the upstream petroleum sector is to provide a framework to facilitate exploration and development of petroleum resources while gaining and maintaining a social licence to operate in concert with local communities and existing industries. This requires confidence that the regulatory regime is adequately addressing risks to the environment, water resources, public health, worker safety and the broader community. Policies to address risk should be evidence based, informed by scientific research and commensurate with the identified risk. A risk management framework that is informed by both the likelihood of an event occurring and the likely consequences of that event is crucial to effective regulatory responses.

CSG and other unconventional gas regulation is continuing to evolve across Australia. The Queensland regulatory regime is an example for other jurisdictions in that it has facilitated the establishment of a CSG industry while providing protection for the environment, water resources, farm land and communities. The Queensland Competition Commissioner is currently undertaking a review of the regulatory regime that applies to CSG to identify further improvements in the areas of regulatory overlap and duplication, regulatory effectiveness and the cost of regulation. It has the potential to become a useful point of reference for other states and territories as they develop unconventional gas regulation.

South Australia is also taking a proactive approach to unconventional gas development through its *Roadmap for Unconventional Gas*. The Roadmap covers the the life-cycle of shale and tight gas projects in South Australia including logistics, supply chains and infrastructure. The Roadmap emphasises community confidence in the ability and impartiality of regulators as fundamental to ensuring continued gas development.

Better approaches to regulation such as these should be encouraged. Regulatory changes which are not based on scientific evidence run the risk of either delaying investment or requiring an unnecessary commitment of resources by both proponents and regulators, potentially without commensurate benefits. Compliance cost may be further exacerbated by complex and heavily conditioned approvals. As an example, the CSG–LNG project approvals in Queensland each contained over 300 Commonwealth conditions and hundreds of additional state approval conditions - some of which overlap but require extensive reporting and monitoring by both companies and regulators.

Box 2.2 CSG, communities and co-existence

The growth in the CSG industry over the past decade and its expected future development pose significant challenges for governments, communities and the industry. As in the development of other extractive resource industries, the sustainable development of the sector requires balanced consideration of its social, environmental and economic benefits and costs.

However, unless a community is engaged with and supportive of CSG operations, the industry will struggle to maintain its social licence to operate. Governments may be able to provide assistance in this engagement and communications.

Australian governments are focused on developing a world-class CSG industry while also protecting the environment, water resources and human health. These protections are best delivered within an evidenced-based regulatory framework and a commitment to leading practice by industry. Governments are addressing real risks and understanding community perceptions in the development of CSG and adopting a regulatory approach and specific policies that respond to these risks and perceptions.

As an example of government action addressing both risks and perception, a national assessment of chemicals associated with CSG extraction in Australia is being led by the National Industrial Chemicals Notification and Assessment Scheme within the Commonwealth Department of Health and is expected to be completed in 2014. The assessment will examine human health and environmental risks from chemicals used in drilling and hydraulic fracturing for CSG extraction in Australia. This will build on a March 2013 Queensland Health risk assessment of health complaints and environmental monitoring data which found that a clear link cannot be drawn between the health complaints of some residents and the local CSG industry.

In order to maximise the benefits and minimise the likelihood of potential conflict over land access, a shared commitment to co-existence between the CSG industry, other land-users and governments is needed. The industry has improved its performance in this area over the past few years in partnership with communities and government. Queensland now has a strong Land Access Framework which provides strong protections for land-owners and agricultural practice and certainty for industry. Queensland has more than 4,000 land access agreements in place between land owners and the CSG industry with zero in dispute (APPEA 2013).

Where regulatory regimes generate unnecessary delays, this can lead to adverse impacts on the community. This has been a particular focus of debate in New South Wales, which has seen potential CSG developments delayed or suspended on the back of uncertainty and a shifting moratorium. If these projects proceed they could supply important tranches of gas to the domestic market and support local investment and jobs.
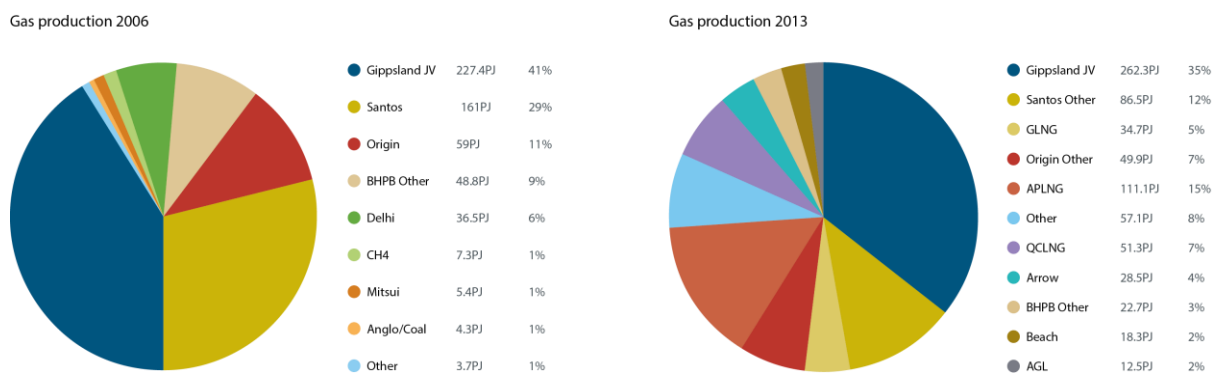
Victoria has similarly restricted the development of new gas supply through a moratorium on the CSG industry (and the potential of tight gas in Gippsland and shale gas in the Otway Basin). The recent report of the Victorian Gas Market Taskforce specifically recommended the removal of the moratorium on fracture stimulation and the issuance of new CSG exploration licences subject to reforms being implemented.

The principles of leading practice regulation for CSG are set out in the SCER-endorsed *National Harmonised Regulatory Framework for Natural Gas from Coal Seams* which was finalised in May 2013. The Framework sets out a range of indicators for leading practice regulation around environmental protection, water management, chemical use and well integrity all of which are key areas of concern for communities and the industry. All jurisdictions endorsed the Framework at the May 2013 SCER meeting and its use in legislative practice would provide protection for the environment and water resources, assurance for communities and certainty for industry.

2.6 Reserves and production ownership

The entry of major multinational oil and gas companies into gas production in eastern Australia is commensurate with the financial backing and technical requirements necessary for large gas projects. In 2006, the top three producers (the Gippsland Joint Venture, Santos and Origin Energy) produced nearly 85 per cent of eastern Australia's gas (Figure 2.4). By 2013, the top three producers accounted for 62 per cent of gas production, and APLNG had become the second largest supplier behind the Gippsland Joint Venture. Overall, the number of companies with production has remained relatively stable at around 20, and there continues to be a larger number of smaller companies involved in exploration that are yet to bring gas resources into production.

Figure 2.4: Eastern market gas production, 2006 and 2013, by company

Gas production 2006

Gippsland JV	227.4PJ	41%
Santos	161PJ	29%
Origin	59PJ	11%
BHPB Other	48.8PJ	9%
Delhi	36.5PJ	6%
CH4	7.3PJ	1%
Mitsui	5.4PJ	1%
Anglo/Coal	4.3PJ	1%
Other	3.7PJ	1%

Gas production 2013

Gippsland JV	262.3PJ	35%
Santos Other	86.5PJ	12%
GLNG	34.7PJ	5%
Origin Other	49.9PJ	7%
APLNG	111.1PJ	15%
Other	57.1PJ	8%
QCLNG	51.3PJ	7%
Arrow	28.5PJ	4%
BHPB Other	22.7PJ	3%
Beach	18.3PJ	2%
AGL	12.5PJ	2%

Source: EnergyQuest (2006, 2013b).

The ownership of reserves is somewhat different. In 2006, the Gippsland Joint Venture controlled nearly 40 per cent of 2P reserves in eastern Australia (Figure 2.5). In 2013, that proportion had dropped to around 7 per cent (Figure 2.5), although the volume of the reserves had not decreased significantly. The key factor has been the growth in CSG reserves, both in Queensland as a result of the LNG developments and in New South Wales, where there is potential for CSG to supply significant quantities of gas if regulatory issues can be addressed.

Figure 2.5: Eastern market gas reserves, 2006 and 2013, by company

Gas reserves 2006

Gippsland JV	4656PJ	39%
Santos	2367PJ	20%
Origin	1890PJ	16%
Other	950PJ	8%
Woodside	477PJ	4%
BHPB Other	432PJ	4%
QGC	423PJ	3%
Delhi	293PJ	2%
AWE	203PJ	2%
CH4	191PJ	2%

Gas reserves 2013

Gippsland JV	3382PJ	7%
Santos Other	3242PJ	6%
GLNG	5242PJ	10%
Origin Other	797PJ	2%
APLNG	13382PJ	26%
QCLNG	10402PJ	21%
Arrow	8592PJ	17%
Other	3152PJ	6%
AGL	2231PJ	4%
Metgasco	426PJ	1%
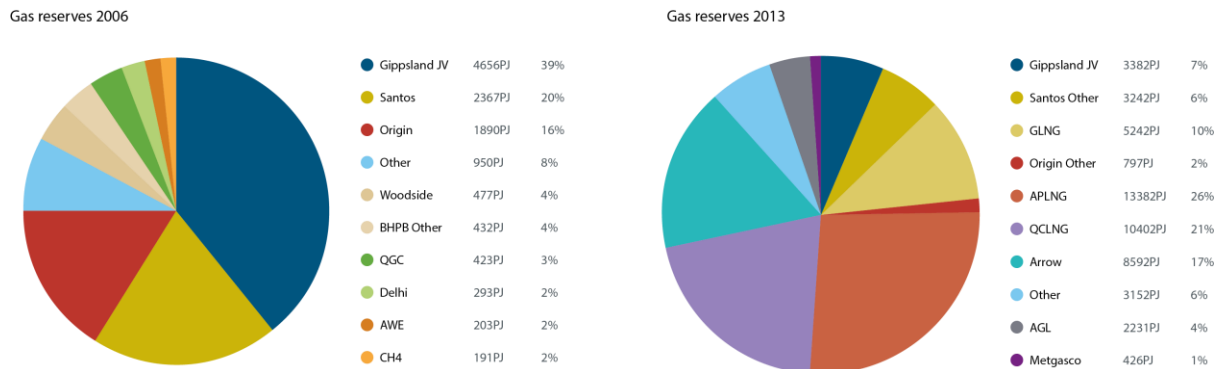
Source: EnergyQuest (2006, 2013b).

2.6.1 Tenure

In Queensland, the LNG projects and the companies associated with them (Origin Energy and Santos) have considerable acreage, mostly in the Surat and Bowen basins. The acreage positions of the LNG projects and associated companies were obtained either through pre-existing tenements or through a series of acquisitions from late 2007. These included the acquisitions of Queensland Gas Company and Sunshine Gas by BG Group, Arrow and Bow Energy by Shell and PetroChina, Tipperary Corp and Eastern Star Gas by Santos, Origin Energy's purchase of interests from Pangaea CSG and AGL's purchase of BHP Billiton's CSG interests.

Santos and Origin Energy also have interests in the Cooper–Eromanga basins, and Santos has tenements in the Gunnedah Basin of New South Wales. Both companies also have offshore acreage in the Otway Basin, while Origin Energy has acreage in the Bass Basin and Santos in the Gippsland Basin. A number of other smaller companies have interests in the Surat and Bowen basins including Westside Energy Corporation, which is developing a project on the south-eastern edge of the Bowen Basin.

Control of tenements is more diverse in other areas, including the Galilee Basin and the Cooper–Eromanga basins. Competition for acreage in the Galilee Basin is influenced by higher development costs, longer distances to markets and some disappointment at CSG drilling results to-date which has made the area less attractive for the first tranche of LNG production. While Santos and Origin Energy have significant presence in the Cooper–Eromanga basins through their interests in the Cooper Basin Joint Venture, others, such as Beach Energy, Senex Energy, Drillsearch Energy and Strike Energy, also have significant positions in the basins.

2.7 Cost of development

The cost of new gas developments has increased rapidly worldwide: the average cost more than doubled between 2004 and 2008 (GA and BREE 2012). Over the same period, development costs in Australia increased sharply and have increased further as a result of technology requirements, skills shortages, tight engineering and construction markets and productivity issues.

McKinsey and Company (2013) observe that the cost of building new LNG projects in Australia is now about 20–30 per cent higher than it is for competitors in North America and East Africa. Development projects for both LNG and conventional oil and gas projects have all seen cost over-runs. The three CSG–LNG projects in construction in Australia have all had cost revisions; for example, the development of the Gippsland Joint Venture – Santos Kipper/Turrum/Tuna project has doubled in cost to over $4.5 billion.

CSG development at the scale required to support LNG development is a new phenomenon in Australia and, although many costs and technical aspects remain uncertain, production costs are relatively high. This high cost is reflected through the exploration and appraisal, well drilling and development, and project execution phases. In October 2013, the proponents of the GLNG and APLNG projects announced their agreement to share pipeline infrastructure to avoid duplication of a 140 km pipeline and alleviate some capital costs.

Gas reserves are also getting more expensive to find and extract. Figure 2.6 shows that CSG and unconventional gas resources will become increasingly costly to develop. Costs will increase as development and production moves from existing conventional and known unconventional gas reserves to less certain resources (deeper and more distant from supporting infrastructure). The current average cost of development for new unconventional and CSG gas is already approaching $5/GJ (IES 2013) and will continue to rise.

Figure 2.6: Development costs for unconventional gas and CSG ($/GJ)
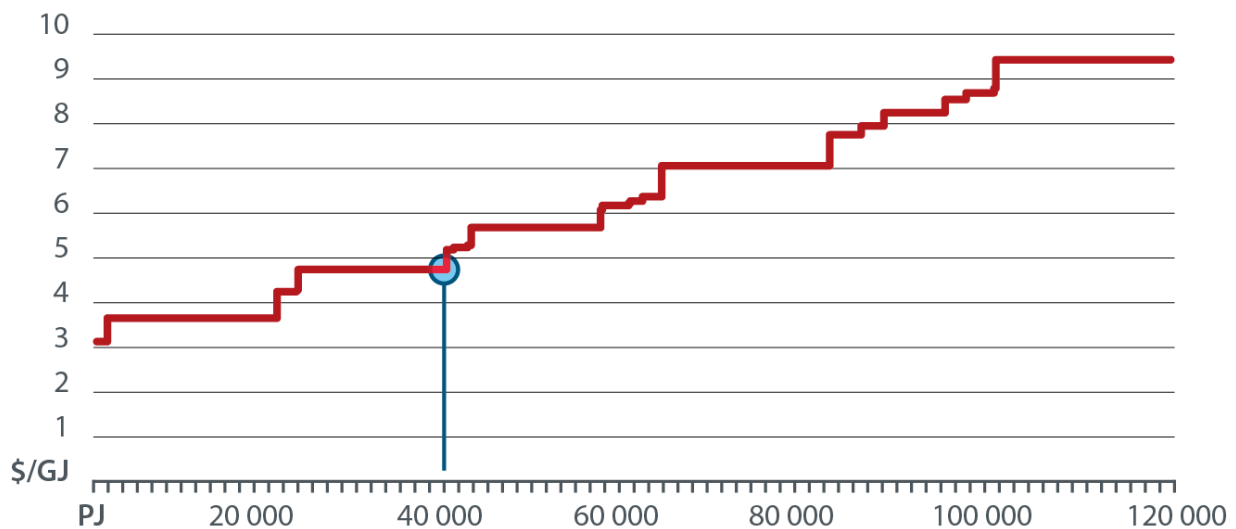
Source: RLMS in IES (2013).

Unit costs of supplying gas have also risen following the dedication of a large proportion of recently discovered gas reserves to meet LNG export obligations. The commitment of reserves to the CSG–LNG projects has placed further upward pressure on domestic prices because of the increasing costs for developing, producing and transporting new gas supply.

While the pull of high LNG demand and prices will be the main factor in developing the majority of additional gas resources, the viability of commercialising further reserves for the domestic market will be affected by uncertainty about future gas prices and the ability of domestic gas users to pay more for gas.

2.8 Conclusions

The eastern gas market has significant gas resources that are currently being developed. In addition, there are significant potential reserves that could be developed in the future if it becomes economically viable to do so. The timeline for proving up and extracting these resources will be important for satisfying domestic and LNG export demand, and eventually replacing gas from depleting basins.

The rapid development of LNG export capacity has created uncertainties relating to domestic supply, the timeline for developing CSG production and the performance of CSG wells. All the LNG projects are striving to meet gas requirements for project start-up and ongoing operations using a number of strategies. Project schedules are tight, and even minor delays, weather interruptions or poor well performance could lead to the diversion to the LNG projects of additional gas from sources traditionally supplying the domestic market.

These uncertainties are manifesting as significant issues in the market. Better information about CSG development progress could help to reduce uncertainty and improve the ability of market participants to manage risk. Actions by governments to remove any unnecessary technical and regulatory barriers to development will also be important in bringing on additional gas supply, enhancing upstream project completion and improving market outcomes.

3. Demand

While supply uncertainty is a key issue, the demand response to higher gas prices in this rapidly changing market is a matter of debate. Perspectives on this issue are becoming increasingly important to the price discovery process. This chapter considers gas demand in the eastern market and how demand in major sectors of this market may be affected.
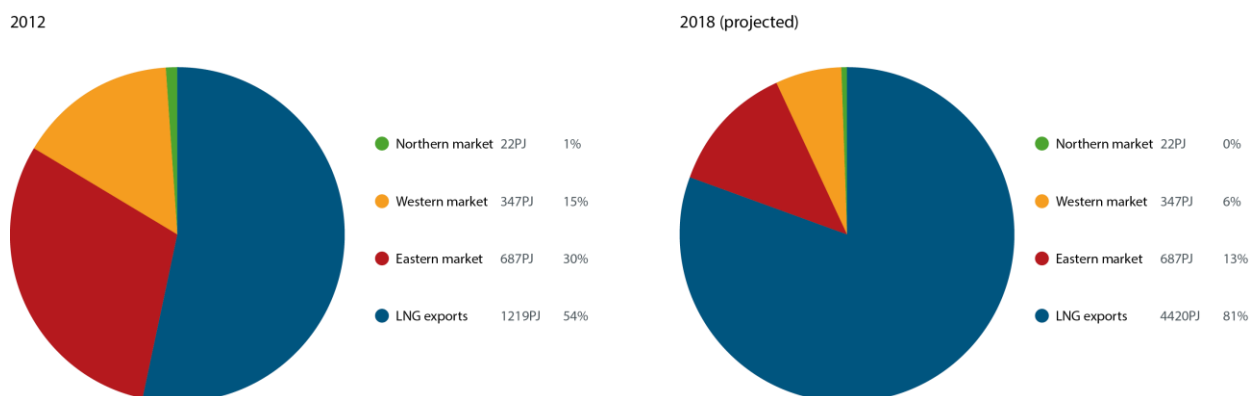
3.1 Overview

In 2012, the eastern market was the largest of the three domestic gas markets in Australia with around 65 per cent (687 PJ) of total Australian domestic gas production (1,056 PJ). A further 1,219 PJ was exported as LNG from Western Australia and the Northern Territory (Figure 3.1).

The eastern gas market has several distinct features compared to Australia's other gas markets that contribute to its demand profile:

- a larger population compared to the northern and western Australian gas markets, centred on several major demand centres

- greater climatic variability, which contributes to a seasonal gas demand profile

- an electricity generation sector dominated by coal-fired generation

- a high percentage of the national manufacturing base.

Both the western and northern gas markets incorporate existing LNG export industries; have small populations, less climatic variability, greater dependence on gas-fired electricity generation and a strong gas demand component from the mining industry.

Figure 3.1: Australian gas consumption, 2012 and projected 2018, by market

2012

● Northern market	22PJ	1%
● Western market	347PJ	15%
● Eastern market	687PJ	30%
● LNG exports	1219PJ	54%

2018 (projected)

● Northern market	22PJ	0%
● Western market	347PJ	6%
● Eastern market	687PJ	13%
● LNG exports	4420PJ	81%

Source: AEMO (2013), EnergyQuest (2013a). BREE (2013a).

LNG exports from Australia are set to grow significantly over the next five years and will account for 81 per cent of gas production when all seven projects currently in construction are completed. LNG exports from the eastern market are expected to commence from 2014 and result in a trebling of gas demand from east coast production centres by 2016–17.

Historically, total gas demand in the eastern market has grown steadily. The three largest demand components – large industrial uses, gas powered electricity generation, and residential and commercial demand – exert different influences on total demand growth in individual states and territories. Figure 3.2 shows the share of each sector's demand in the five states and territories that comprise the eastern market (the Australian Capital Territory is shown as part of New South Wales demand).

Overall, residential demand has grown steadily in line with population and economic growth. Electricity generation demand has grown more rapidly, driven partly by historically low gas prices, expectations about carbon prices and gas-powered generation targets set in Queensland. Large industrial demand has moderated as manufacturing activity has declined, driven by cost pressures, a high dollar and import competition. As storage options are limited, most gas is directly consumed in the demand centres of Brisbane, Sydney, Canberra, Melbourne and Adelaide.

Large industrial use (manufacturing and mining) is the largest demand component in the market, accounting for 43 per cent of demand in 2012. Gas-powered generation is responsible for one-third of total eastern market demand, most of which is base load generation in Queensland and South Australia with a small amount of peaking demand during the summer. Residential and commercial use is relatively stable, although it exhibits a definite seasonal peak that corresponds with winter demand in the south-eastern states. Queensland has very low gas penetration into the residential market. The three major gas demand sectors and their component demand drivers are discussed in further detail below.

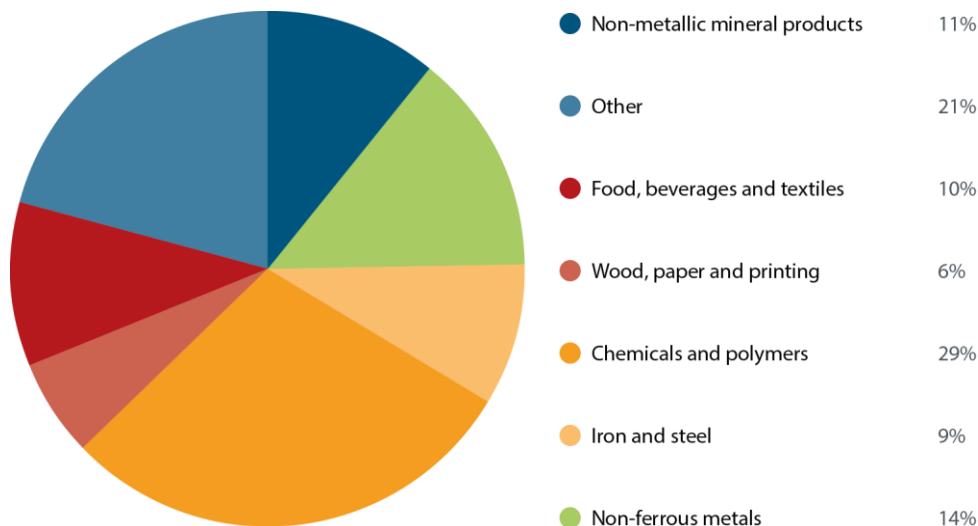**Figure 3.2**: Eastern market primary consumption of gas, 2012, by sector
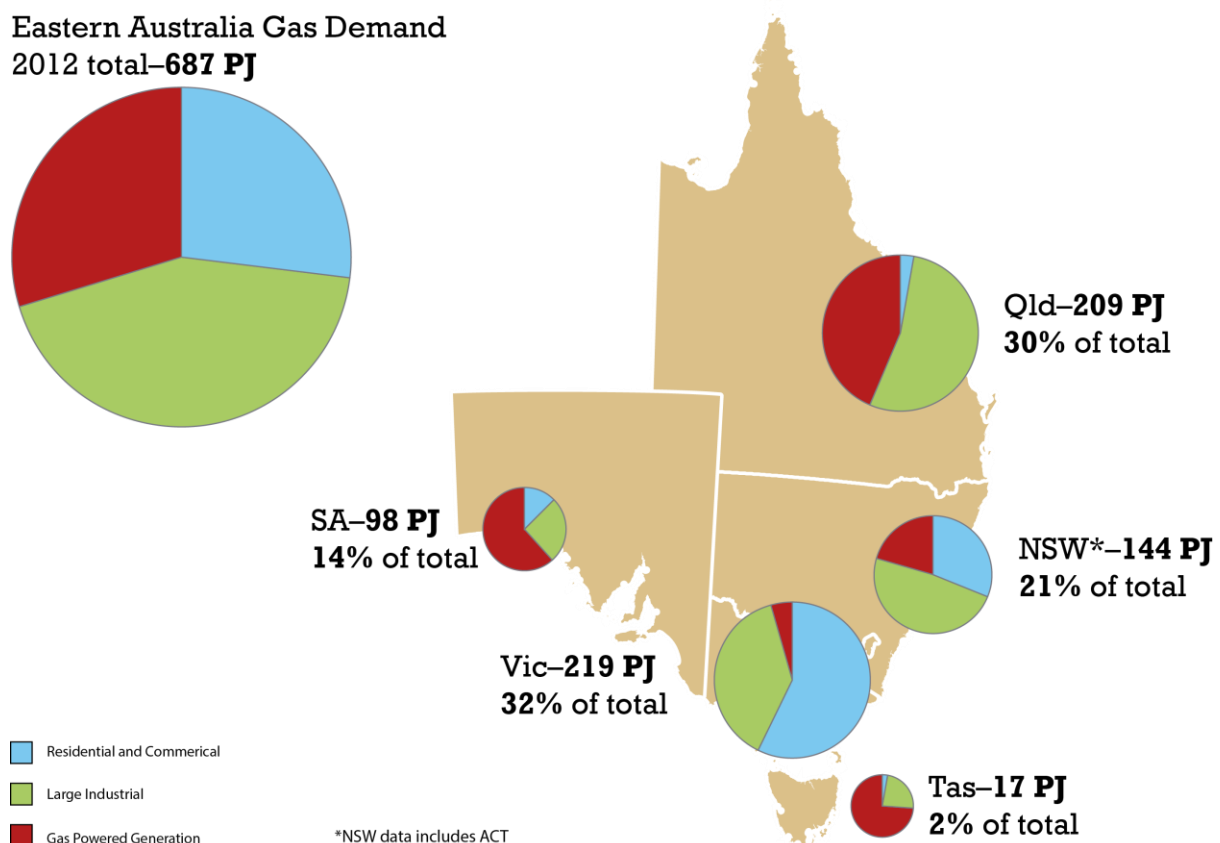
Source: AEMO (2013).

3.2 Industrial gas demand

Industrial gas demand (comprising industrial and manufacturing consumers with gas demand greater than 10 TJ/a) makes up a significant proportion of total demand in the eastern market, consuming approximately 300 PJ, or 44 per cent of total gas supplied. Industrial demand is characterised by few but very large consumers of gas, most notably metals processors and refiners, chemicals and plastics producers, and non-metallic mineral processors. Figure 3.3 shows industrial sector gas consumption in the eastern market.

Figure 3.3: Gas consumption, 2011–12, by industrial subsector

● Non-metallic mineral products	11%
● Other	21%
● Food, beverages and textiles	10%
● Wood, paper and printing	6%
● Chemicals and polymers	29%
● Iron and steel	9%
● Non-ferrous metals	14%

Source: BREE energy statistics database.

Over the longer term, growth in gas consumption for industrial purposes has been declining steadily over time (Figure 3.4). The decline suggests that, even when gas prices were low, industrial users of gas were facing a range of factors (for example, the value of the dollar or import completion) which were impacting on manufacturing activity and growth.
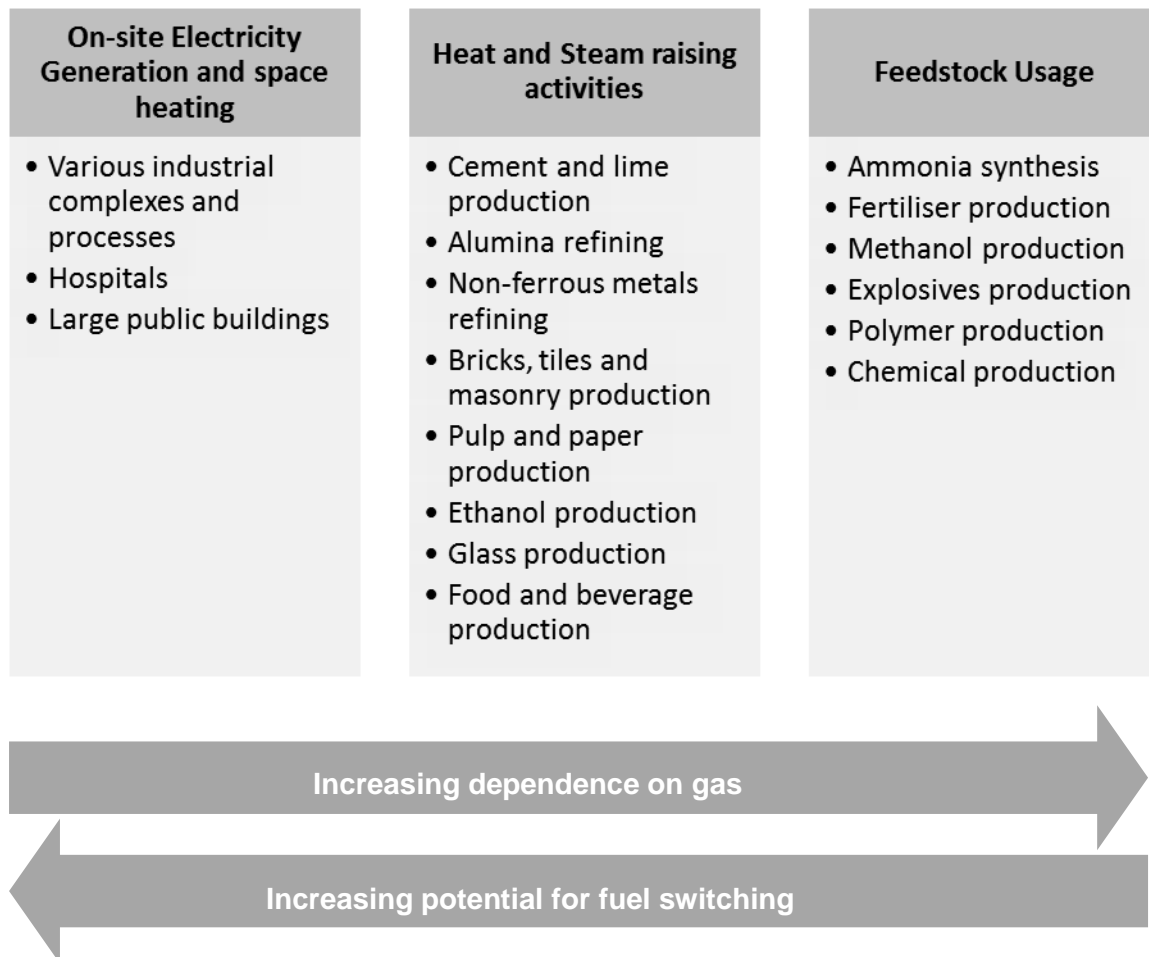
Figure 3.4: Change in gas consumption in the industrial sector, 1990–91 to 2011–12
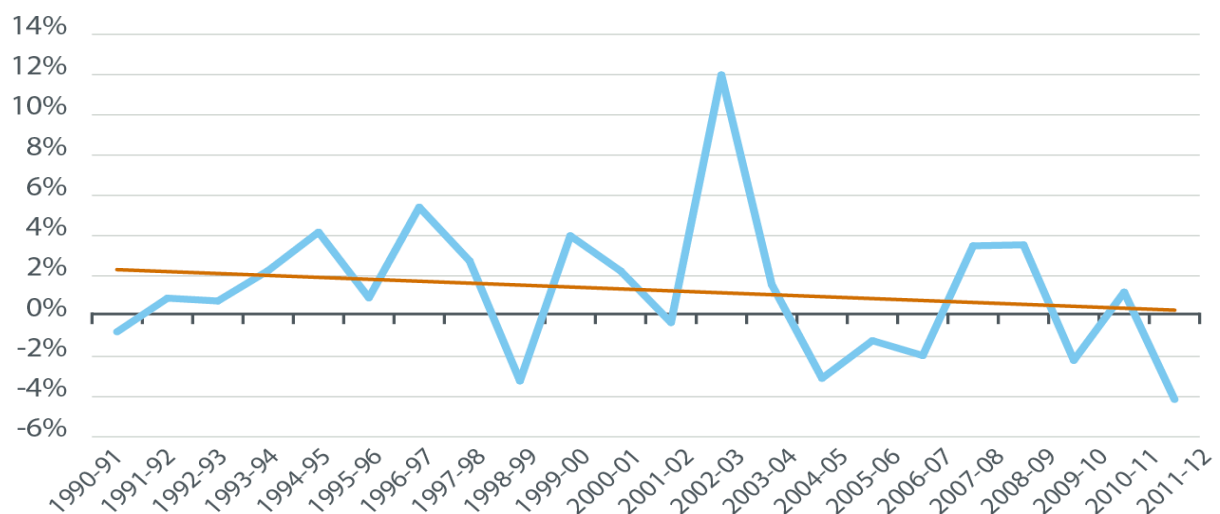
Source: Energy Supply Association of Australia.

The opaque nature of the contract market and a price environment characterised by historically relatively small increases allows little insight into the potential demand response of large gas users to rapid and large price increases. The response of large industrial gas users to increases in the gas price will depend on the significance of gas in their production processes and the potential for fuel switching. Figure 3.5 categorises industrial users based on their use of gas.

Figure 3.5: Major gas user categories

On-site Electricity Generation and space heating	Heat and Steam raising activities	Feedstock Usage
• Various industrial complexes and processes • Hospitals • Large public buildings	• Cement and lime production • Alumina refining • Non-ferrous metals refining • Bricks, tiles and masonry production • Pulp and paper production • Ethanol production • Glass production • Food and beverage production	• Ammonia synthesis • Fertiliser production • Methanol production • Explosives production • Polymer production • Chemical production

Increasing dependence on gas →

← **Increasing potential for fuel switching**

Fuel substitution or switching options (e.g. electricity) are available for space heating, low-temperature heat and low-pressure steam generation. However, this may require large capital expenditure and therefore, be difficult to justify when energy prices are highly uncertain.

Activities involving gas-fired cogeneration and tri-generation (cooling, heating and generation) facilities may also respond to rising gas prices by reducing their gas consumption. For example, rather than operating a site-specific small generation plant, gas users in this category have the option to reduce their gas use and cease exporting surplus electricity to the National Electricity Market (NEM), operating as peak generators only, or source all their electricity directly from the network.

Industrial activities using gas for very high temperature heat and high-pressure steam or as a feedstock are relatively more constrained in being able to respond to rising gas prices. In these industrial processes, gas is either a significant input in the manufacture of the end product or is the preferred fuel for those processes (which might not be the case for fuels with lower energy content or higher cost). Feedstock users typically perform the most gas-intensive production activities and therefore, gas comprises a significant share of input costs.

The trend of declining manufacturing activity in New South Wales, Victoria and South Australia may result in further reductions in gas demand from the large industrial sector. Notable closures have occurred or have been announced by Shell (Clyde Refinery) and Norsk Hydro (Hunter Valley aluminium smelter). Other large industrial gas users, such as BlueScope Steel and Caltex, have announced restructuring or changes to operations that will reduce gas consumption. These changes may also have implications for electricity demand which could reinforce the effects on gas-powered generation. The exception to this trend may be in Queensland, where large industrial gas demand is projected to grow (AEMO 2013). In some circumstances, some large industrials may have the opportunity to on-sell their contracted gas supply.

3.2.1 Major industrial users' energy intensity

Energy intensity in the Australian economy has been declining over time, and rising gas prices are likely to contribute to a continuation of that trend. The extent to which the intensity of gas use could be reduced has the potential to provide some buffer against the current tight market although the ability for individual businesses to make such changes varies widely.

Detailed energy efficiency data obtained during the course of this study did not lend itself to empirical analysis and assessment of these issues. However, it did reinforce the key point that an important component of Australia's overall energy intensity is the gas intensity of large industrial activities. The extent to which this will change in response to rising prices depends both on the availability of substitutes and the ability to pass through costs. In as much as activities are highly dependent on gas either as a feedstock or for specialised industrial processes, have low per unit margins, or are competing with lower price imports, the ability to absorb higher prices or justify investment in adaptation is significantly constrained.

3.2.2 Major industrial users' recent contracting experience

As discussed further in Chapter 5, large industrial gas users typically seek long-term gas supply agreements (GSAs) to deliver a degree of future price certainty and assist them in making major capital investments in plant upgrades or new capacity. They also typically seek gas transportation agreements (GTAs) to guarantee a flow of gas via pipelines for industrial processes that often operate continuously.

A number of major industrial gas users have provided information in confidence to the study on their experiences in negotiating GSAs, but it was generally not possible to objectively verify this data. There were reports of increasing difficulties in attracting firm offers for supply, despite high prices, but it was similarly difficult to ascertain whether this is a transient or sustained problem. A recent survey published by the Australian Industry Group, while fairly subjective, is broadly consistent with the themes of submissions made to the study (Box 3.1).

Box 3.1: Australian Industry Group survey on contracting experiences

The Australian Industry Group surveyed eastern Australian gas-using businesses in April and May 2013, enquiring about their current gas use, contracts sought and investment impacts.

The survey found that nearly half of the 61 respondents were looking for a new gas contract. Of those:

– nearly 10 per cent could not get an offer at all

– a third could not get a serious offer

– a quarter could get an offer from only one supplier.

On contract prices, the survey found that:

– of the businesses being offered prices, those seeking relatively short-term contracts to commence in 2013 were seeing offers of $5.12/GJ (a moderate uplift)

– for everyone else seeking later or longer contracts, the average offer was $8.72/GJ (more than double the historical price).

Source: Australian Industry Group (2013).

Approaches to gas contracting vary by user, and historically often involved only direct discussion with an existing retailer. Gas contracts have typically been long term and often renewed with little or no renegotiation of terms and conditions, including only minor readjustments for incremental price increases. As a result, large industrial gas users have previously not needed to acquire a comprehensive understanding of gas markets in order to undertake contract negotiations.

Longstanding methods of gas contracting has served large industrial gas users well in the past but the rapidly changing dynamic of the eastern market may require different strategies to manage gas portfolios. Some large users in Australia are responding by adopting innovative strategies to secure gas supply including:

- negotiating directly with or investing in upstream explorers and producers
- embracing shorter term contracts or less restrictive terms and conditions
- establishing in-house gas market expertise
- developing relationships with specialised gas procurement consultants.

3.3 Electricity generation

Demand for gas for electricity generation has grown over recent years as a result of relatively low gas prices, expectations around carbon prices and gas-fired generation targets set in Queensland. Gas-powered generation is unique in that it produces both base-load and peaking electricity supply. It is a significant source of demand for gas in the eastern market, consuming around 201 PJ in 2012 (approximately thirty per cent of gas demand in eastern Australia). Approximately 13 per cent of total National Energy Market (NEM) electricity supply was provided by gas-powered generation in 2011–12 (Figure 3.6).

Figure 3.6: NEM (eastern market), 2011–12, by energy source

|	
Black coal	50%
Brown coal	25%
Natural gas	13%
Hydro	7%
Wind	3%
Other	2%
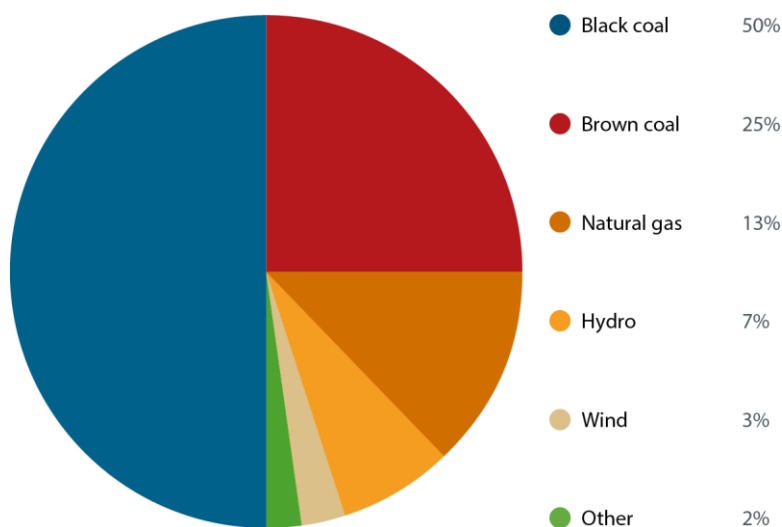
Note: 'Other' includes oil, bioenergy, solar photovoltaic and multi-fuel fired power plants.
Source: BREE (2013b).

Because about 30 per cent gas demand in the eastern market is from electricity generation, future changes in demand for electricity have the potential to significantly affect the gas market. The main factors affecting electricity demand in the NEM include consumers' responses to rising electricity prices, energy efficiency measures, and installation of residential solar photovoltaics.

Factors including gas prices and the Renewable Energy Target (RET) will affect the amount of gas-powered generation in the NEM. Figure 3.7 presents AEMO (2013) modelling of gas demand for electricity generation. It shows a significant decline in gas demand for electricity generation in all jurisdictions in the NEM from 2012, with the largest falls in Queensland. AEMO expects an average annual decline in gas-powered generation of 9.8 per cent from 2014 to 2022, followed by a steady recovery to 2032 as electricity demand improves.

Figure 3.7: Annual gas use in electricity generation, 2008 to 2033
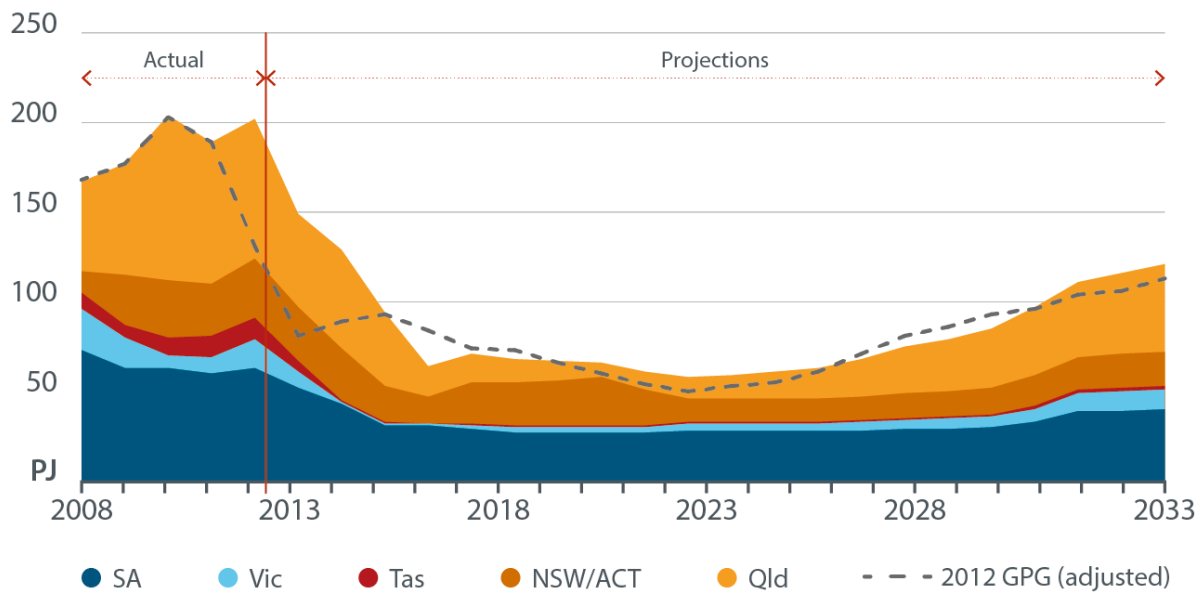
Source: AEMO (2013).

Declines in gas consumed in electricity generation are particularly noticeable in South Australia and Queensland – states that have traditionally had higher levels of gas generation and local gas production. Gas production that typically would have been supplied from the Cooper–Eromanga basins (South Australia) and the Surat–Bowen basins (Queensland) for gas-powered generation may well flow to supply LNG export projects.

The reduction in demand for gas from base- and intermediate-load generators is likely to see existing gas generation capacity mothballed or used to meet periods of peak demand in summer. If a base-load combined cycle gas turbine plant that typically uses between 30 PJ and 40 PJ of gas per annum switches to a peak generation role, gas use would fall to 5 PJ per annum or less. Significantly lower demand for gas-fired base-load electricity generation would result in large volumes of gas being made available to other sectors of the market.

The integration of gas-powered generation with the LNG projects will lead to generation capacity increasingly being used as a balancing item for LNG production. Origin Energy, QGC (BG – Condamine power station – 144 MW) and Arrow (Braemar 2 – 495 MW) all have generation capacity, which can be used to manage feed-in gas for LNG production. These plants are likely to be used extensively to manage gas demand during ramp-up to full LNG production and assist optimisation of operations when the LNG trains are running at capacity.

3.4 Residential gas demand

Residential and commercial gas demand, often termed mass market demand (comprising users of less than 10 TJ/a), is an important component of demand in the eastern market. It accounts for approximately 187 PJ or around 27 per cent of the total eastern market demand in 2012 (AEMO 2013). Residential and commercial demand is mainly temperature dependent and has a strong seasonal winter peak, attributable to gas demand for space and water heating in New South Wales and Victoria.

Residential and commercial demand in the eastern gas market is dominated by Victorian consumption. Victoria, and to a lesser degree New South Wales, have far more extensive gas distribution networks for mass market customers. Queensland has very low gas penetration in the mass market – 5 PJ compared to 122 PJ in Victoria (BREE 2013c).

A significant demand response to higher wholesale gas prices in this sector is unlikely in the near- and medium-terms. Although an increase in the wholesale price of gas will increase the retail price, this component only accounts for about 30 per cent of the retail price and consumers are relatively slow in switching from gas to electricity appliances.

3.5 Conclusions

Projections of gas demand in the eastern market have changed considerably over the last few years as the implications of factors affecting the wholesale gas price have become clearer. In the period of interest to the study, it is reasonable to assume gas demand by the electricity generation sector will significantly decline, the residential and commercial sector will experience relatively steady demand, and while demand in the large industrial sector is in a declining trend, the extent of the impact of higher prices remains uncertain. Therefore, the most significant and uncertain element of the debate on demand is primarily around the impact on large industrial users, particularly manufacturers.

While the effect of rising gas prices on industry costs and competitiveness should not be understated, this needs to be viewed in the context of a range of factors that impact on the overall competitiveness of manufacturing and industrial gas users. Firms with the highest sensitivity to gas prices are those in trade-exposed, gas-intensive industries. Firms that use gas as a feedstock are particularly vulnerable due to a lack of substitutes. Other industrial activities may require large capital investments in order to switch fuels where uncertainty about the price and availability of gas makes long-term investment decisions difficult. If firms that are sensitive to gas prices expect the price to remain high for a long time they may also exit the industry. Demand will respond to price.

In the current environment, the extent and rate of change in the gas market and the consequent supply uncertainty appear to be making it difficult for firms to be confident that they are being offered gas on fair terms. At the same time, suppliers may be cautious when making offers or competing for domestic contracts. Gas users may therefore need to adapt their contracting and supply strategies to secure supply. The difficulty being experienced by large gas users highlights the need for improving information available in the market to facilitate informed and efficient short and long-term purchasing decisions.

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4. Infrastructure

4.1 Overview

Development of new upstream gas supply and effective competition in wholesale gas markets is linked to access to efficiently priced gas transportation, processing and storage services which in turn relies on a combination of efficient price signals and regulatory arrangements. To date, this framework has arguably worked well – in recent years there has been a consistent build and redevelopment of infrastructure to meet growing demand. However, significant changes are occurring in the gas market and there is debate about whether commercial and regulatory arrangements could be improved to address supply tightness and rising gas prices.

Internationally, there are a number of examples of reforms to gas market infrastructure underpinning the development of more liquid and competitive gas markets, but the translation of those experiences to Australia, and the eastern market in particular, is not straightforward. The eastern market is small in comparison with many international markets, with few major producers and a reliance on a limited number of processing facilities, pipelines and storage options.

While transportation, processing and storage costs are a lower proportion of delivered gas prices than production costs, they have the potential to affect long-term gas supply outcomes by limiting the competitiveness of primary contracts for gas supply and the efficiency of spot and forward pricing markets. In addition, storage is subject to some physical limitations but is potentially important in maximising short-term availability in a tighter market.

All these components of infrastructure are underpinned by a diverse and complex range of products and services that are subject to limited specific regulation. The National Gas Law and subordinate National Gas Rules commenced on 1 July 2008, bringing regulation of natural gas pipelines in eastern states under a national energy framework. While initiatives such as the National Gas Market Bulletin Board have placed some important information into the gas market, many aspects of gas infrastructure operations and service offerings are characterised by limited information in the public domain.

The lumpy nature of gas infrastructure investment can also affect the economics of upstream production and exploration. Established pipeline and processing infrastructure with available capacity in an area that is prospective for gas will greatly enhance development potential (the Cooper Basin is a good example of existing infrastructure facilitating new development). However, smaller explorers and developers attempting to develop new gas resources with acreage distant from existing infrastructure may have difficulty proving enough reserves to justify the processing and pipeline investment required to produce and get gas to market.

4.2 Existing infrastructure

4.2.1 Transmission pipelines

Historically, the long distances and high capital costs associated with gas pipeline infrastructure development in Australia required government investment to ensure that projects proceeded. Gas market reforms in the 1990s led to structural reforms of the vertically integrated gas utilities and the privatisation of most government-owned transmission pipelines.

Figure 4.1: Major Australian gas pipelines
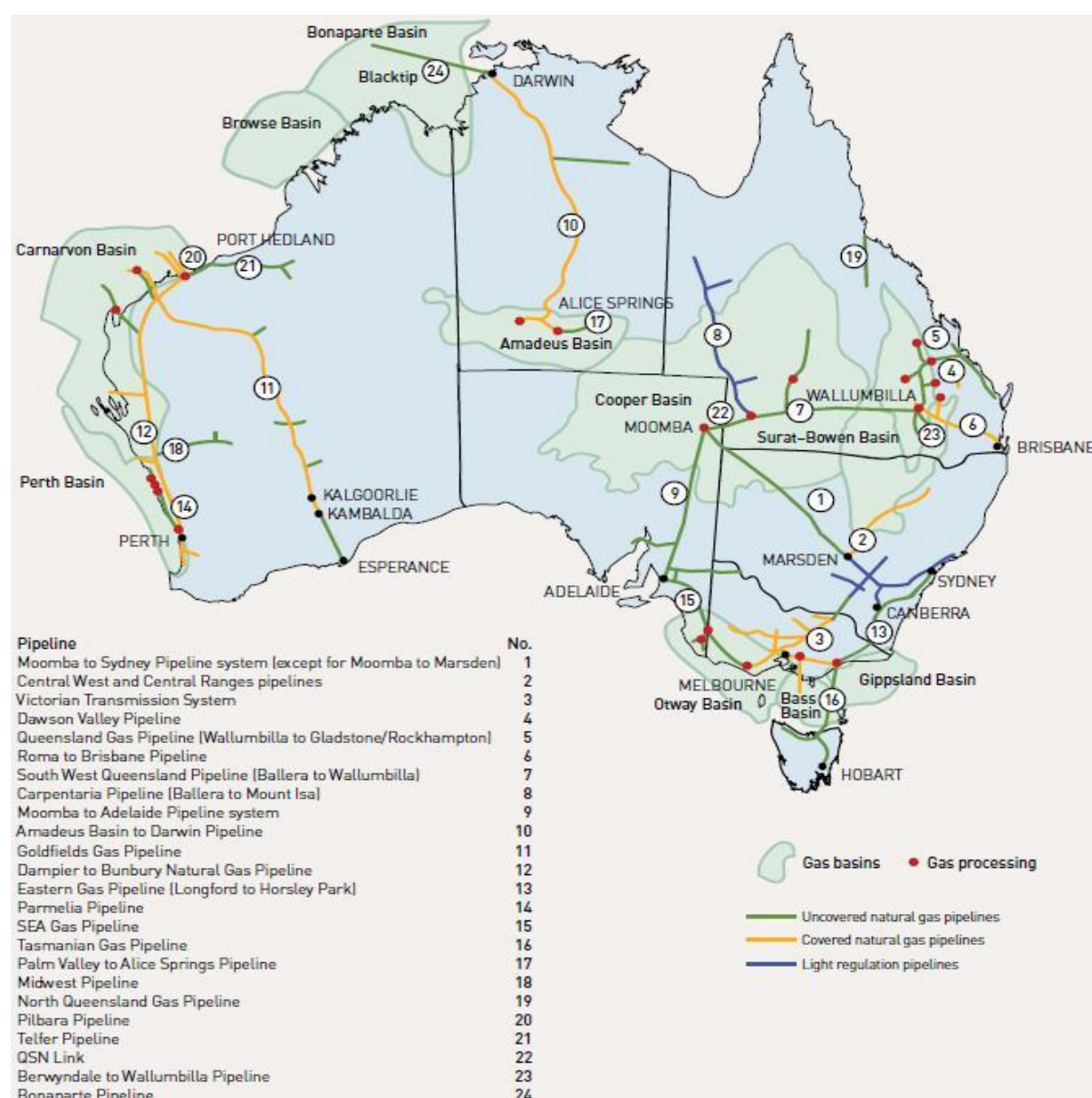
Source: AER (2012).

Significant investment in the regulated and unregulated transmission sector has occurred over the past 10 years for the expansion of pipeline capacity, including the Eastern Gas Pipeline, the New South Wales – Victoria Interconnect, the Moomba to Sydney Pipeline, the Roma to Brisbane Pipeline, the Queensland Gas Pipeline and the Victorian Declared

Transmission System. New pipelines have also been constructed, including the SEA Gas Pipeline in 2004, the Queensland to South Australia/New South Wales Link in 2009 and the three pipelines serving the LNG projects at Gladstone in Queensland currently under construction.

Gas transmission investment typically involves large and lumpy capital projects to expand the capacity of existing pipelines (through compression, looping or extension) or to build new infrastructure. In most cases, these investments have occurred in response to firm long-term commitments by shippers and were underwritten by either long-term foundation transportation contracts or with direct buyer/producer ownership interests in the pipeline.

Figure 4.1 illustrates the location of major gas pipelines in Australia. There is a significant degree of pipeline interconnection in eastern Australia, so it is technically feasible to transport gas between producing basins and many demand centres. However, various technical and commercial limitations may prevent the optimal use of the network in a more dynamic market. In addition, the development of new markets (such as LNG exports) and access to new sources of supply will depend on the cost and availability of transportation services.

Further detail on the pipeline network in eastern Australia is in Table 4.1. APA Group is the largest owner of pipelines (in terms of number, total distance and capacity) in eastern Australia, followed by the significant assets of Jemena.

During 2012, the APA Group expanded its gas transmission portfolio through a $1.4 billion acquisition of Hastings Diversified Utilities Fund, which owned Epic Energy. The Epic portfolio included the Moomba to Adelaide Pipeline, the South West Queensland Pipeline, the Queensland to South Australia/New South Wales Link and the Pilbara Energy Pipeline (in Western Australia). As part of the terms of the deal agreed by the Australian Competition and Consumer Commission, APA had to divest its ownership of the Moomba to Adelaide Pipeline. Since the separation of AGL and APA Group, no gas retailer or producer holds any significant transmission or distribution pipeline infrastructure.

Pipeline operators offer various ancillary or supplementary services, including storage capability (park-and-loan services) and risk management services that are highly valued by shippers. A pipeline operator that has control over a larger share of the network arguably has more capacity to offer such services, which may be bundled with, or priced into, the primary capacity right.

From consultations with pipeline companies, the regulator and shippers, it appears likely that the importance of non-reference or negotiated services has increased with the changed dynamics of the gas market. For example, managing swings in demand and optimising supply portfolios that can switch between alternative energy sources must rely on a more diverse range of services than a traditional forward haul service.

Table 4.1: Ownership of gas transmission pipelines

	Pipeline	Owner	Operator	Length (km)	Capacity (TJ/day)	Covered
Qld	North Queensland Gas Pipeline	Victorian Funds Management Corporation	AGL and Arrow	391	108	Not
	Queensland Gas Pipeline (Wallumbilla to Gladstone)	Jemena	Jemena	629	142	Not
	Carpentaria Pipeline (Ballera to Mount Isa)	APA	APA	944	119	Light
	Berwyndale to Wallumbilla Pipeline	APA	APA	112	na	Not
	Dawson Valley Pipeline – Access arrangement 2007–15	Westside 51%, Mitsui 49%	Westside	47	30	Yes
	Roma (Wallumbilla) to Brisbane Pipeline	APA	APA	582	219	Yes 2012-17
	Wallumbilla to Darling Downs Pipeline	Origin Energy	Origin Energy	205	400	Not
	South West Queensland Pipeline (Ballera to Wallumbilla)	APA	APA	756	181	Not
	Queensland to South Australia/New South Wales Link (Ballera to Moomba)	APA	APA	180	212	Not
NSW	Moomba to Sydney Pipeline (plus laterals and NSW – Victoria Interconnect	APA	APA	2028	420	Partial (light)
	Central West Pipeline (Marsden to Dubbo–Minor)	APA	APA	255	10	Light
	Central Ranges Pipeline (Dubbo to Tamworth–Minor)	APA	Jemena	294	7	Light
	Eastern Gas Pipeline	Jemena	Jemena	795	268	Not
Vic.	Victorian Longford to Melbourne Pipeline	APA	AEMO	174	1030	Yes
	Victorian South West Pipeline	APA	AEMO	203	353	Yes
	VicHub	Jemena	Jemena	n/a	150	Not
	South Gippsland Natural Gas Pipeline	Multinet Gas	Jemena	250		Not
SA	Moomba to Adelaide Pipeline	Epic Energy	Epic Energy	1185	253	Not
	SEA Pipeline System (Port Campbell to Adelaide)	APA 50%, REST 50%	APA	680	303	Not
Tas.	Tasmanian Gas Pipeline (Longford to Hobart)	Palisade Invest. Partners	Tas. Gas Networks	734	129	Not
LNG	APLNG Pipeline	APLNG	Origin Energy	362	1560	Not
	GLNG Pipeline	GLNG	GLNG	435	1420	Not
	QCLNG Pipeline	QCLNG	QCLNG	334	1410	Not

Source: AER (2012), AEMO (2013) and company updates

4.2.2 Distribution networks

Distribution networks transport gas from high-pressure transmission pipelines to residential, commercial and smaller industrial users. The cost of these networks is the main component of retail gas prices to these customers. Envestra currently owns three of the distribution systems, Jemena has an interest in two and APA has an equity interest in four, through its equity stake in Envestra and GDI (EII). Full economic regulation, where access terms and conditions are submitted to and approved by the Australian Energy Regulator, applies to all but the Tasmanian distribution network.

4.2.3 Gas processing facilities

Raw gas extracted from a field does not meet pipeline specifications for transportation or end consumption. Therefore, gas processing facilities are required at production centres to remove other impurities and separate higher value liquids from the gas. The current expansion of CSG production is leading to the establishment of a large number of processing facilities across the Surat and Bowen basins.

Processing facilities for the eastern market have a wide range of capacities. For example, there are three processing plants servicing the Otway Basin in Victoria (Iona, Minerva and Otway, with a combined capacity of around 840 TJ per day) that process just over 100 PJ per year. In comparison, the Longford gas plant has a processing capacity of 1,145 TJ per day and is currently processing around 250 PJ per year from the offshore Gippsland Basin gas fields.

Many stakeholders have raised access to processing infrastructure, on reasonable terms, as a crucial driver of upstream development and supply response. The scale and location of the large Moomba gas plant (with a capacity of 390 TJ per day) makes it of particular interest to the future development of gas, including gas from unconventional sources.

The Cooper Basin Joint Venture is substantially upgrading these facilities to both increase production capacity and handle gas compositional changes. As further resources are proved up in the area and new projects are developed, access to the Moomba facilities may be important in bringing on new supply for some of these projects.

4.2.4 Storage

As the dynamics of the gas market change, there is an increasing focus on the potential role of storage. Storage that is close to demand centres enhances the ability of energy retailers and wholesalers to manage peak requirements and provides a hedge against spikes in the spot market price. Storage also improves the ability of gas producers to maintain a more constant production profile from plants and fields, rather than altering production to match daily demand fluctuations. As is noted in Table 4.2, eastern Australia currently has three different types of storage facilities.

- Large transmission pipelines provide storage capacity as the pressure within the pipeline moves from low to high. Gas stored in this fashion is referred to as 'linepack'. The

capacity to store linepack depends on the size and length of the pipeline and its maximum and minimum operating pressures. This type of storage is used to manage intra-day demand forecast errors (although it can supply for longer periods on some pipelines).

▪ Depleted gas fields are used to re-inject gas into the geological structure, which originally contained gas. When the gas is withdrawn from the structure, it may require some reprocessing to ensure that it meets gas quality specifications. There is understood to be limited potential for additional significant geological storage on the east coast, as geological structures need high porosity and permeability to be suitable for this purpose.

▪ Small-scale LNG plants convert gas to LNG, which is re-gasified and re-injected into the network when required.

Depleted gas fields used as storage include the Moomba and Ballera underground storage facilities operated by Santos for the Cooper Basin Joint Venture - combined, these are the largest storage facilities in the eastern Australian network. Other storage in Queensland includes the Roma underground storage facility (operated by Santos) and the Silver Springs storage facility (operated by AGL). Energy Australia operates the Iona storage facility in western Victoria near Port Campbell, and Origin Energy operates the small Newstead facility in New South Wales. There is a purpose-built peak shaving LNG facility in Dandenong (Victoria) which is owned and operated by APA, and another LNG storage facility is being developed by AGL near Newcastle (New South Wales).

As gas supplies to New South Wales become tighter, the Newcastle gas storage currently under construction will be a major contributor to gas supply on peak demand days. Storage in Queensland (Roma and Silver Springs) and storage at Moomba is being used as a management strategy for the ramp-up phase of the CSG–LNG projects in Queensland: gas is placed in storage and will be recovered as the LNG projects commence production.

Several transmission pipelines, such as the Moomba to Sydney Pipeline, the Eastern Gas Pipeline, the Moomba to Adelaide Pipeline, the South West Queensland Pipeline and the Queensland to South Australia/New South Wales Link, also offer storage services. Some producers and users have highlighted the potential for additional storage to help optimise the capacity of current processing facilities, and as an option for improving short-term availability and addressing peaks. In addition to these facilities, some gas-powered generators have built dedicated pipeline laterals in close proximity to their plants to store gas.

Table 4.2: Eastern Australian gas storage facilities

Facility	Ownership	Storage capacity (PJ)	Location
Iona underground gas storage	Energy Australia	22	Depleted gas fields (Iona, North Paaratte and Wallaby) near Port Campbell, Victoria
Ballera underground storage	Cooper Basin JV	13.7	Depleted Chookoo field in Queensland in Cooper-Eromanga basins
Moomba underground gas storage	Cooper Basin JV	85	Depleted fields in South Australia in Cooper-Eromanga basins
Silver Springs gas storage	AGL	35	Depleted Silver Springs and Renlim gas fields near Roma

Facility	Ownership	Storage capacity (PJ)	Location
Roma underground storage	Santos Ltd	unknown	Depleted fields in the Roma area
Newstead underground storage	Origin Energy	2	Depleted Newstead gas field
Dandenong LNG storage	APA	0.7	LNG in Melbourne
Newcastle LNG storage (in construction)	AGL	1.5	LNG in Newcastle

Source: AEMO (2013) and company reports.

4.3 Infrastructure access and pricing

The arrangements for regulating access to infrastructure are complex, and have been canvassed in a range of major policy reviews in recent years. It is important to appreciate this context when considering policy in this area. The August 1993 report of the National Competition Policy Review (the Hilmer report) is the core document setting out the principles of competition policy at the administrative level in Australia (Hilmer et al. 1993). The Council of Australian Governments (COAG) agreed to put into effect the Hilmer report's recommendations in February 1994, and it remains a key influence on the way pipelines are currently regulated.

The Hilmer report provided the following six key principles to guide the development of competition policy:

- no participant in the market should be able to engage in anti-competitive conduct against the public interest

- as far as possible, universal and uniformly applied rules of market conduct should apply to all market participants, regardless of the form of business ownership

- conduct with anti-competitive potential said to be in the public interest should be assessed by an appropriate transparent assessment process, with provision to demonstrate the nature and incidence of the public costs and benefits claimed

- any changes in the coverage or nature of competition policy should be consistent with, and in support of, the general thrust of reforms:

  - to develop an open, integrated domestic market for goods and services by removing unnecessary barriers to trade and competition

  - in recognition of the increasingly national operation of markets, to reduce complexity and administrative duplication.

4.3.1 Processing

Third-party access arrangements are governed by the *Competition and Consumer Act 2010*, under which third parties can gain access to existing essential infrastructure services of national significance. Access is available either through the declaration of the facility by the relevant minister following an application to, and recommendation from, the National Competition Council or by the lodging of an access undertaking by the facility owner with the

ACCC. Regulated access is also available where an infrastructure service is subject to a state/territory access regime.

The *Competition and Consumer Act 2010* excludes declaration of a service which amounts to the use of a production process. This is likely to exclude upstream production facilities from third-party access requests under the Act.

The Productivity Commission released a draft report on 28 May 2013 on third party access arrangements in Part IIIA of the Competition and Consumer Act. While the Productivity Commission did not consider the National Gas Law, the two regimes are similar and the Commission concluded that processing facilities should not be included as facilities covered in the National Access Regime.

The implication of current arrangements is that, in practice, the sharing of processing facilities is largely a matter of whether the technical and commercial objectives of asset owners can be satisfied. These may include strategic objectives, for example to exclude competitors from access. To the extent to which this is a barrier to entry over time may be limited by competitors building smaller or alternative plant (the economies of scale for building new processing may not be as large as with transmission pipelines). However, it is also the case that more ready access to processing in the proximity of reserves could accelerate supply response. It is therefore not surprising that a number of parties have raised concerns over the difficulties with negotiating access to processing infrastructure in the current environment.

4.3.2 Transport services

In general, there is a presumption that regulation of pipelines should be avoided (unless a need is clearly demonstrated) because:

- pipeline owners are generally prohibited from involvement in other aspects of the gas supply chain reducing incentives for discrimination in the provision of pipeline access
- in the absence of vertical integration, pipeline investment under the contract carriage model has been achieved in the absence of regulation, as shippers have been prepared to underwrite such investments in order to obtain a firm capacity right
- the interconnectedness of the eastern market creates the potential for competition between pipelines
- wealth transfers between parties are not strictly inefficient, unless the result is increased barriers to entry and restricted competition in dependent markets
- regulation comes with the risk of stifling investment.

Third party access to gas pipelines is governed by the National Gas Law which contains provisions for pipelines to be 'covered' and as a result subject to either light regulation (which essentially mirrors the regulation and coverage criteria available under the *Competition and Consumer Act 2010*), or full regulation which requires the provision of an access undertaking by the pipeline operator.

For a pipeline to be appropriate for coverage, it must meet all of the pipeline coverage criteria listed in Box 4.1. The National Competition Council is responsible for advising on whether the pipeline coverage criteria are met in the same way as it advises on declaration of services under the *Competition and Consumer Act 2010*.

Box 4.1: Pipeline coverage criteria

- Access (or increased access) to the pipeline services provided by means of the pipeline would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the pipeline services provided by means of the pipeline.

- It would be uneconomical for anyone to develop another pipeline to provide the services provided by means of the pipeline.

- Access (or increased access) to the pipeline services provided by means of the pipeline can be provided without undue risk to human health or safety.

- Access (or increased access) to the pipeline services provided by means of the pipeline would not be contrary to the public interest.

The regulatory framework anticipates the potential for market conditions to evolve, and includes a mechanism for reviewing whether a particular pipeline needs economic regulation and the extent of that regulation. The AER is the responsible regulator of gas pipelines.

Under full regulation this extends to assessing the revenues needed to cover efficient costs and provide a commercial return on capital, and deriving reference tariffs for the pipeline. Of the transmission pipelines listed in Table 4.1, four are subject to full regulation (including the Victorian Declared Transmission System) and a further four are subject to light regulation.

An access arrangement sets out the terms and conditions under which third parties can use a pipeline, including the rights and obligations of both pipeline owners and shippers. It must specify:

- at least one reference service likely to be sought by a significant part of the market
- a reference tariff for that service
- capacity trading requirements
- queuing requirements (if applicable) to determine user priorities for spare capacity
- how the pipeline is to be expanded or extended
- how access requests are to be dealt with.

Under light regulation, the pipeline provider determines its own tariffs. The provider must then publish relevant access prices and other terms and conditions on its website. In the event of a dispute, a party seeking access to the pipeline may ask the AER to arbitrate.

Most pipelines are 'uncovered', meaning that they are not subject to economic regulation. For uncovered pipelines, third party access is negotiated bilaterally on commercial terms and conditions that may differ from those set through regulatory processes. Disputes are also resolved via commercial processes as set out in individual gas transportation agreements.

When a new pipeline is built it will initially be classed as uncovered (that is, not regulated) and will remain uncovered unless someone makes a successful coverage application to the National Competition Council. Pipeline owners may also voluntarily submit a full access arrangement to the AER at any time (Part 4, Chapter 3 of the National Gas Law). Covered pipelines may become uncovered if they no longer meet the pipeline coverage criteria under the National Gas Rules. A pipeline developer can also apply for a no coverage determination that provides for a 15-year exemption from regulatory coverage for greenfield pipelines in limited circumstances.

4.3.3 Models for pipeline access and pricing

Two different models are used in the eastern gas market for managing access and pricing on transmission pipelines: a contract carriage model and a market carriage model.

The contract carriage model covers approximately three-quarters of the eastern market's total transmission capacity. Under this model, users must individually negotiate a contract with pipeline owners, which is almost always for firm capacity (expressed as a maximum daily quantity) to allow forward haulage of gas between nominated points of the pipeline network.

Firm capacity reservations are property rights and can be traded between shippers in a secondary market. They usually have significant take-or-pay obligations attached to the capacity reservation for the term of the contract. Additional services, such as 'as available' forward haul, backward haul, and park and loan may also be included in the contract or priced separately. Relevant factors influencing the performance of contract carriage pipeline services include the regulatory setting, the efficiency of pricing structures and mechanisms for allocating primary capacity, and access to competitive markets for trading secondary capacity.

Under the contract carriage model, pipeline owners generally underwrite the construction of new pipelines or major expansions in pipeline capacity with long-term, bilateral foundation contracts (gas transportation agreements) that typically have 10- to 15-year terms.

In contrast to the rest of the eastern gas market, Victoria operates under a market carriage model. This model provides open access to infrastructure without requiring a commitment to capacity contracts, thereby allowing a greater number of buyers and sellers to transact, which increases the depth and liquidity of the wholesale market. In particular, open access to transport infrastructure and a fully integrated gas supply chain strengthens competition, and makes individual buyer and seller behaviour less important.

Under the market carriage access model, an independent system operator optimises the entire system to ensure that gas volumes can be injected and withdrawn from the system as nominated. Under the Victorian model, revenues and costs for pipeline infrastructure services are fully regulated by the AER. A zonal-distance-based volumetric tariff is applied, which recovers approved costs subject to a price control formula and demand assumptions. In order to be recovered from users, new investment must be approved by the AER under the tests prescribed in the National Gas Rules.

Each model has strengths and weaknesses that need to be considered in the context of the particular demands of the market and the physical relationship between supply and demand centres. A major strength of the contract carriage model is that it has historically facilitated significant pipeline investment. The key issues relevant to its performance given the transformation in the market are as follows:

- it may lack flexibility in response to changing market dynamics.
- contracts allocate a high proportion of risk to shippers.
- if demand for the service is too uncertain, pipeline operators may not have the incentive to invest in capacity to efficiently meet future growth needs.

In the current environment, shippers appear hesitant to enter into long-term contracts to underwrite capacity expansion until there is clarity about how the market will balance over the longer term. From a pipeline owner's perspective, the value of long-term contracts arises precisely because they largely insulate investment returns from market changes, including any altered dynamics of the wholesale market and associated changes to gas pipeline use. That is, long-term contracts for gas transportation services avoid the 'stranding' of pipeline assets by providing a high level of confidence on revenue streams to pipeline owners, irrespective of market developments and changes to the needs of market participants.

There appears general agreement that the Victorian market carriage model is performing well in terms of facilitating new entry by producers and retailers, and also ensuring that parties with the highest willingness to pay for gas can access the transport network (K Lowe Consulting 2013). Also, the link to wholesale market outcomes is likely to support efficient use of the transport network to the extent that network congestion aligns with wholesale market prices. A key issue with the model is whether it facilitates efficient investment in new assets, since the absence of firm transmission rights means users may be less likely to underwrite new capacity investments.

4.3.4 Pipeline investment

The existing investment models have delivered, in the main, an interconnected network of long-distance transmission pipelines that have provided a reasonable degree of basin-on-basin competition in eastern Australia. The development and expansion of much of this network has been founded on and underwritten by long-term contracts under a contract carriage model, whereby users take on a large part of the market risk of each development.

With growing uncertainty over supply in the eastern market, gas customers are being offered increasingly shorter-term contracts from gas suppliers and aggregators. While recognising the essential link between long-term risk and sunken investment, in the transition to a new market linked to the international LNG trade, there is a concern that users will be unwilling to bear the financial risks of long-term contracts in the light of the significantly greater uncertainties about the source and volume of flows (and even the direction of flows).

Notwithstanding these challenges, a significant amount of pipeline and processing infrastructure is being constructed or has been proposed for the eastern market. Proposed projects include the Queensland–Hunter, Lions Way and Wallumbilla to Bulla Park pipelines.

The Northern Territory Government is also exploring the idea of a connecting the Territory to the eastern market.

Given potential impediments to supply in New South Wales, infrastructure management and investment may take on a particular significance in that jurisdiction. A number of strategies are being developed that will assist in managing supply risk for New South Wales. Those strategies include the following:

- APA is expanding the capacity of the South West Pipeline by over 70 TJ per day, which will allow increased access to the gas supplies from the Otway Basin and the underground storage at Port Campbell, for delivery to New South Wales through the Interconnect if required.

- APA is also expanding the Interconnect to allow contracted flows of between 100 and 118 TJ per day from Victoria into New South Wales, which are to be agreed between APA and AEMO. The expansion is under relatively short-term contracts with the shippers. This is in addition to the Eastern Gas Pipeline, which can flow 288 TJ per day to New South Wales at full capacity (and which can be expanded by compression if required).

- AGL is constructing an LNG peak shaving facility at Newcastle with a daily send-out of up to 120 TJ per day.

There may also be potential to supplement supply on peak days with storage in the Moomba to Sydney Pipeline or at Moomba.

4.3.5 Pipeline access

In general, the pipeline operators offer a traditional firm service, and also a range of more flexible services such as as-available, park-and-loan and backhaul services. In the transition to a more dynamic market, it is reasonable to expect that such supplementary services will be in greater demand. This applies to regulated as well as unregulated pipelines, as regulated pipelines are only required to nominate one regulated service. It may be appropriate to include these supplementary services in any review or monitoring activities.

In addition to the primary pipeline services offered by the pipeline operators, there is a 'secondary market' of gas swaps and pipeline capacity trades. These transactions between shippers and other users are usually bilateral and confidential.

In the area of secondary markets:

- the secondary trades in pipeline capacity lack transparency. There is no spot market and no forward market to reveal prices and availability.

- the state short-term trading markets and the Victorian gas market operated by AEMO provide some transparency on prices where gas is sold into the retail end of the market, but the upstream gas supply and transport prices, contracts and arrangements are still opaque.

- AEMO is establishing a gas trading hub at Wallumbilla, which will assist in revealing prices and availability of upstream gas at an important trading location. APA is also proposing to establish a pipeline capacity trading facility at the same location, which will

facilitate the operation of the gas trading hub. Together, these should provide a transparent spot price (and possibly a forward price) for gas and pipeline capacity in Queensland – the immediate point of connection between the LNG export and domestic markets. This work is also expected to provide important insights into the potential for secondary capacity trading.

Some information on aggregated pipeline capacity utilisation is publicly available online via AEMO's National Gas Market Bulletin Board (www.gasbb.com.au). Pipeline capacity utilisation data indicates that there are periods throughout the year when some pipelines have significant volumes of unutilised capacity (for example, the South West Queensland,[1] Moomba to Sydney, Moomba to Adelaide, SEA Gas, Longford to Melbourne and Eastern Gas pipelines).

The capacity of many pipelines is heavily utilised on peak days: five of the 20 pipelines listed in Table 4.1 (excluding the three LNG project pipelines in construction) used over 90 per cent of rated capacity and another five used over 80 per cent of rated capacity on peak days in 2012. The South West Queensland Pipeline, the Queensland to South Australia/New South Wales Link and the Tasmanian Gas Pipeline were operating at around 50 per cent of their capacity on peak days in 2012 (K Lowe Consulting 2013:10).

In summary, the transition to a new market is likely to be dominated by greater uncertainty and higher risks, and users may require more flexibility and greater transparency in both the primary and secondary services offered on pipelines.

4.4 Conclusions

Of the infrastructure services in the gas supply chain, pipeline services have the greatest opportunities to develop in response to the significant changes occurring in the eastern gas market. While the pipeline network has been adequate to meet the demand for gas in the eastern market, it has grown incrementally as a result of individual pipelines servicing large increases in demand from specific areas, rather than with a view to maximising the efficiency and interconnectedness of the gas supply chain as a whole.

Both the contract carriage and market carriage model have strengths and weaknesses, particularly with regards to implications for barriers to entry and investment signals. Given the changing dynamics in the eastern market, whether the current arrangements best serve the needs of the future market is an open question.

While access to efficiently priced infrastructure should not be seen as a panacea for upstream competition problems, it does affect market outcomes. It may therefore be possible to improve market fundamentals by increasing transparency around infrastructure utilisation and (in some cases) pricing.

Greater visibility of negotiated outcomes between pipeline owners and shippers, and appropriate monitoring of the service offerings of pipeline operators and of the secondary capacity trading markets will assist in improving transparency.

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[1] From 2014–15, considerable additional volumes of gas from Santos's portfolio will be transported via the recently expanded South West Queensland Pipeline.

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5 Markets and price discovery

5.1 Overview

The current gas market structure, which is based mainly on long-term bilateral contracts, has underpinned significant investment in exploration and pipeline infrastructure, allowing reliable gas supplies. However, there is a growing debate about whether this structure is appropriate to the current gas market, which is characterised by high levels of uncertainty about both supply and price.

Of particular concern is a lack of market transparency, which creates the potential for inefficient outcomes. It is likely that no single market participant has clear visibility of the market outside its direct areas of influence, and significant resources are expended on trying to determine likely market outcomes (quantities, prices and terms). Compounding this uncertainty is a degree of asymmetry of information on gas supply that favours gas producers over gas consumers.

A lack of market transparency and high levels of supply uncertainty are not unique to the eastern gas market. However, many commodity markets have well-established trading arrangements and futures markets that provide the opportunity for producers and consumers to manage future price and supply risks. Those instruments enhance liquidity in the trading market and give an indication of future price movements.

In an efficient market, gas is allocated to where it is most valued, production is driven by least-cost outcomes, clear signals on supply and demand are available to the market, and constraints on either supply or infrastructure are resolved over time. Under current market conditions, there are commercial incentives for suppliers to be reluctant to negotiate and lock in long-term contracts for relatively large amounts of gas. The difficulty being experienced by some large consumers in obtaining and negotiating gas contracts during the transition highlights the importance of having price discovery processes in which the market has confidence.

This chapter discusses these issues by examining pricing instruments, how prices are discovered, the role of international markets, sources of market information and alternative market models.

5.2 Gas supply contracts

The eastern gas market is dominated by long-term contracts, usually with take-or-pay provisions. Long-term contracts have provided certainty for producers and pipeline operators to undertake the large capital investment that is needed to bring on supply. This model also ensures certainty of supply for users to underpin their own long-term investment decisions.

Contracting for the supply of gas requires the negotiation of a gas supply agreement (GSA) with a producer to supply the gas, and a separate gas transportation agreement (GTA) with a gas transmission pipeline operator to transport the gas.

The terms and conditions of individual GSAs and GTAs are commercial-in-confidence and may differ considerably depending on the needs of the buyer and seller.

The bilateral contract model has been useful as a mechanism for allocating risks to those who should bear it (the investors and their financiers), and yet it is flexible enough to accommodate tailored contract conditions and the pricing of risk by pipeline operators through GTAs.

Box 5.1: GSA and GTA terms and conditions

While GSAs and GTAs are not specifically mentioned in energy laws or rules, certain elements of them are, such as access rights, force majeure and dispute resolution details. Both GSAs and GTAs typically include many of the following elements, although both are also commercial-in-confidence and the terms and conditions of individual contracts can differ considerably:

- parties' responsibilities and obligations

- annual quantities (including seasonal variations) and monthly estimates and daily nomination details

- supply term and supply arrangements, including permitted interruption and quantity variation details

- price review mechanisms and billing and payment obligations and details

- gas quality and measurement details

- details of the sufficiency of proved and probable gas reserves

- provisions to apply in the event of default or termination, mechanisms for resolving disputes and force majeure provisions

- confidentiality details and credit provisions.

GTA terms and conditions typically include:

- forecast, nomination and scheduling with trading of maximum daily quantity (including trading by shipper and restrictions on trade details)

- receipt and delivery point details and obligations and system-use gas and gas imbalance allowances

- additional charges, such as overrun, imbalance and daily imbalance charges

- park-and-loan arrangements

- rights and obligations of the transporter and shipper's warranty and linepack details

- prioritisation of delivery details, gas quality and measurement

- access rights and transportation charges and insurance details

- data and information exchange details

- provisions to apply in the event of default or termination

- mechanisms for resolving disputes and confidentiality provisions

- credit provisions and force majeure provisions.

However, this model is opaque because the terms, conditions and pricing agreements of bilateral contracts are confidential. This lack of transparency hampers price discovery when there is a change in the market, as information is not available outside contracting parties, particularly in a timeframe that is relevant to pricing in a dynamic market.

Contract terms based on the requirements of the individual buyers and sellers also entail potentially significant transaction costs, further reducing the desirability of shorter contracts. For example, negotiations for 'as available' pipeline capacity can take two to four weeks (or longer) to finalise. With most gas supply tied tightly to long-term contracts, there is little supply available for shorter term trading, even though short-term contracts may be attractive at a time of peak prices.

A number of long-term gas contracts have recently expired or will soon expire, compounding the difficulties in the current contracting environment. This has been a particular focus in the debate about assured retail gas supply into New South Wales. While there is a strong drive to re-establish long-term supply contracts to deliver certainty, those contracts would perpetuate high-priced outcomes if they were locked in at the current historically high prices. Conversely, shorter contracts, which may not be attractive to some market participants who seek certainty through long-term contracts, may lead to more efficient and liquid pricing as contracts roll over.

5.3 Gas transportation, processing and storage contracts

GTAs executed between pipeline operators and shippers (predominantly gas retailers) specify maximum daily quantities of gas that may be shipped under prescribed terms and conditions. Shippers then nominate before each gas day how much of their maximum daily quantity they wish to transport.

Gas that is transported under a long-term GTA is shipped on a 'firm' basis whereby pipeline operators are obliged to transport the gas. As gas demand varies from day to day, pipeline operators can also offer non-firm, or 'as available', interruptible gas transportation capacity to the market. However, operators are understood to generally prefer to negotiate long-term GTAs through capacity expansion, rather than selling short-term interruptible contracts for smaller or ad hoc volumes.

Capacity trading can assist in the reallocation of unused pipeline capacity and facilitate the delivery of additional gas to the market – in effect improving the efficiency of existing infrastructure. In turn, this may alleviate some of the need to construct new capacity and prevent unnecessary costs being passed to consumers.

Information on the quantum of existing capacity trade in Australia is limited. It is understood that both unused firm and as-available capacity are currently being traded on a bilateral basis (through gas/capacity swaps and bare transfers), but this trade is rare. Furthermore, there is:

- no requirement for participants to report capacity trades
- limited publicly available data showing the quantum of this trade
- no transparent market mechanism to allocate unused pipeline capacity.

Better pipeline capacity trading information could lower transaction costs, potentially building liquidity in the market (especially in seasonal and short-term trading). For some pipelines, including those experiencing contractual congestion (such as the Moomba to Sydney Pipeline), trading has the potential to increase the utilisation of existing capacity. Even on uncongested pipelines, such as the Moomba to Adelaide Pipeline, there is an opportunity for pipeline owners to compete with existing shippers for the sale of firm capacity.

5.4 Domestic trading markets and price discovery

The efficiency of price discovery has direct relevance for market participants. For users facing significant price rises, efficient price discovery provides assurance that prices are not higher than they should be, and that they provide the right price signals to inform negotiations, investments and risk management strategies.

Gas market reform in Australia has aimed to improve liquidity and transparency in the wholesale gas market. Spot markets have been introduced in Victoria (the Declared Wholesale Gas Market), as well as Adelaide, Brisbane and Sydney (the short-term trading markets, or STTMs) (see Appendix B).

These markets were designed to complement long-term gas contracts and provide an option for making up short-run supply and demand shortfalls. However, they currently trade insignificant gas volumes and may have only a limited relevance to the price of the long-term gas contracts. Liquidity in the STTMs is understood to be low, while the Declared Wholesale Gas Market may have greater liquidity due to the lack of firm capacity. The new voluntary gas supply hub trading exchange being introduced by AEMO at Wallumbilla, provides a further variant which potentially has wider application.

An effective short-term trading market requires mechanisms to enable efficient spot and forward price trading to facilitate risk management. Several recent reviews have flagged the need for further market development, including the development of financial hedging products that are not currently available. Market participants are currently managing their risks through trading practices that may have implications for efficiency and prices. The development of hedging products and/or a futures market may provide tools for market participants to more effectively manage risks in a trading environment, allowing for a larger number of participants and greater liquidity in the market.

5.5 The influence of international markets

A recent development in the domestic contracting environment has been the emergence of oil-linked prices, which establish a link between the price of gas and the international oil markets. While this appears to have been strongly resisted by domestic users, it is widely expected to become a more regular feature of contracting, particularly as LNG exports commence and result in greater substitutability between gas destined for export and gas for domestic uses.

LNG projects are very large and require long lead times during the exploration, field development and construction phases. The scale of investment also requires a long payback period (20 plus years) underwritten by long-term contracts, often with LNG customers taking a direct investment interest in the project. It also requires significant proved gas reserves to provide assured production over the life the project.

Expectations about LNG exports, and how the contracts are priced, are therefore likely to be drivers of price in the future. Given that these arrangements are not transparent, and that non-transparent bilateral contracts dominate the international gas trade, this development may add further complexity and risk creating further uncertainty in the market.

There are diverse views about the outlook for international gas markets, particularly LNG markets. Assessments of the market outlook are material to judgements about when and how many LNG trains are likely to be developed in Queensland, which in turn has major implications for assessing the domestic market outlook.

There is no worldwide benchmark LNG price. This is due to a number of factors, including the relative difficulty and expense of producing and transporting LNG and the relatively few buyers and sellers. In the absence of a single benchmark, LNG prices in supply and purchasing agreements are usually indexed to the average price of an energy commodity over a specific period, such as a week or a month. Prices for three basic types of commodities are used for indexing:

- crude oil – used primarily in the major markets of Japan, South Korea, Taiwan and China. The most well-known is the Japan Customs-cleared Crude (JCC) index, also known as the Japanese Crude Cocktail, which is the average price of customs-cleared crude oil imports into Japan every month, as published by the Japanese Government. The index usually closely tracks the Brent Crude Oil benchmark, the main benchmark for trading international oil

- gas via hub prices – used in contracts supplying the United Kingdom (indexed to the National Balancing Point price) and the United States (indexed to the Henry Hub price)

- substitute energy – such as oil products, coal or electricity; used primarily in LNG contracts supplying continental Europe.

Indexing often uses an S-curve in which the price flattens above agreed maximum prices and below agreed minimum prices to cap prices for buyers and sellers, thereby reducing risk for both.

There are efforts by some LNG buyers to move away from oil and substitute energy linkages for LNG pricing. They believe that a linkage to US Henry Hub prices (rather than an oil price linkage) through proposed LNG exports out of the North America would lead to lower international gas prices. North American gas prices are at historical lows of US$3.50–4.00 per million British thermal units (mmBtu – broadly equivalent to GJ) and are effectively underwritten by the production of liquids. However, it is likely that North American gas prices will rise towards a more realistic cost-of-production level of around US$5–6 mmBtu. Furthermore, the US Henry Hub price does not take into account the cost of transporting LNG. Therefore, it is likely that any difference between oil-linked LNG contracts and Henry Hub–linked LNG contracts will narrow.

Over 90 per cent of production from current and proposed Australian LNG projects is committed under long-term supply and purchase agreements to Asian buyers, mainly in Japan and China, although there are important contracts with India, South Korea and Taiwan. Most Australian supply and purchase agreements in these markets are understood to have LNG prices indexed to the JCC index.

There has been some growth in spot markets, evidenced by the way Japan was able to rapidly increase its LNG supply after the 2011 Fukushima accidents to 86 Mt the following year, from 68 Mt in 2010. This gas is purportedly high priced, but evidence is growing that shorter term, more flexible contracts are now more prevalent.

5.5.1 LNG netback pricing

The common metric for obtaining a comparative value in a domestic market for gas used in the production of LNG for export is the 'LNG netback' price. The netback price is a notional price of gas at a particular point along the gas supply chain. It is calculated by subtracting downstream costs, such as the transport costs of feedstock gas, liquefaction and shipping, from the delivered price of LNG to the export customer. The netback price provides a guide to the upper-bound price a supplier could receive for gas if it were sold for LNG export. Despite this being a relatively simple concept, debate continues about what a netback Gladstone price would be, and how it would be translated to various other locations in the eastern market, as well as about the relevance of the netback price to domestic gas prices.

Domestic gas supply tends to be subject to direct contractual arrangements between gas producers or aggregators and major gas customers, with terms ranging from one to 15 years. Longer term contracts are subject to various price reopening negotiations over the life of the contract. Gas has traditionally been priced using a cost-plus formula in which the contract price paid for gas ex-field is calculated based on the cost of production plus a margin. As the eastern market transitions to being linked to the international market through LNG projects, it is this basis which may shift more to LNG netback terms, rather than there necessarily being an instantaneous flow though of world gas prices to domestic users.

For domestic gas buyers, the linking of the domestic gas market with international markets also increases the complexity of price discovery. Furthermore, factors such as the internal arrangements of LNG joint ventures, netback pricing and LNG train schedules, which can all affect price, tend to be known to gas producers operating in both domestic and international markets but may be unknown to domestic buyers.

5.6 Market information

The market has operated to date in an environment in which key information sets relate to a reasonably static market environment and in which anecdotal evidence and a participant's own experience may be sufficient to inform strategy. Governments have undertaken reforms in recent years to improve market information including initiatives such as the *Gas Statement of Opportunities*, AEMO's Gas Market Bulletin Board, the implementation of access regimes under the National Gas Law, and the trading markets discussed in this report.

The Australian Government and state governments provide information on the status of energy, resources and developments. These include BREE's *Australian energy statistics*, *Australian energy projections*, *Resource and energy major projects* and *Energy in Australia* reports. The *Energy White Paper 2012* (DRET 2012), the *Australian Gas Resource Assessment 2012* (GA and BREE 2012) and the *Australian Energy Resource Assessment* (GA and ABARE 2010) also had considerable information. The Queensland and Western Australian governments also provide regular reports.

While this information provides context to the market and can identify issues and potential risks, it is usually released in an aggregated form and often months after data compilations. The lack of timely and targeted information makes it difficult to assess the risk factors under the pressure of the current rapid transition. A number of private consultancy services provide important insights to the market on these issues, including new developments in price discovery. However, there is a paucity of visible and tradeable gas products or prices, spot or forward, which would assist in risk management and decision-making; and similarly there is a lack of standard terms and conditions to facilitate such trade.

5.6.1 Trading hub prices

While trading hub prices do not necessarily represent long-term contract prices, they can indicate what gas users are willing to pay to balance their loads. As demonstrated in Figure 5.1, spot prices in both the Victorian Declared Wholesale Gas Market and the STTMs are currently in the $5–6/GJ range, having increased from $3–4/GJ in early 2012. There are usually seasonal trends, with higher prices over winter. The most fluctuation has been in the Brisbane STTM due to its relative illiquidity compared to the other STTMs. As in the Declared Wholesale Gas Market, there was a spike in prices over winter 2012, when average weekly prices were reaching $9/GJ. Unlike in the Declared Wholesale Gas Market, STTM spot prices include both gas and transportation costs.

**Figure 5.1:** Average weekly gas prices in the eastern market, January 2011 to July 2013
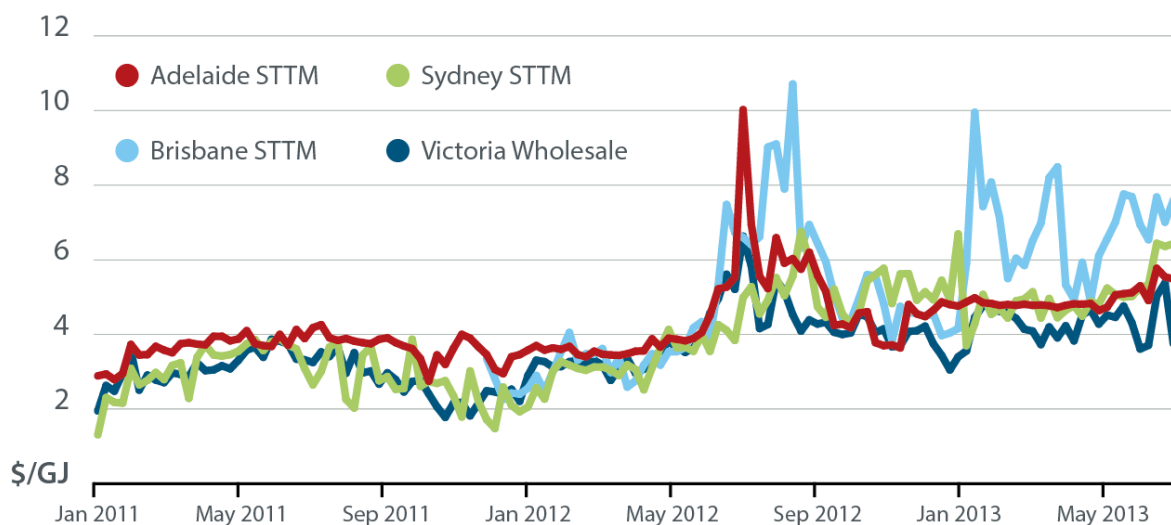
Note: The STTM prices are ex ante and include both the cost of the gas and the cost to transport it to each hub. The Victorian wholesale price is ex post and includes only the cost of the gas.
Source: BREE (2013d).

5.6.2 Price expectations

There is no established forward price for gas, but recent studies have provided views on forward wholesale market prices, as shown in Figure 5.2. As the figure shows, there are diverse views on whether current price increases are transitory for the short or medium term, and whether they will be sustained. These issues are explored further in the modelling and analytical work reported in Chapter 6.

Figure 5.2: Eastern wholesale gas price projections, 2012 to 2034
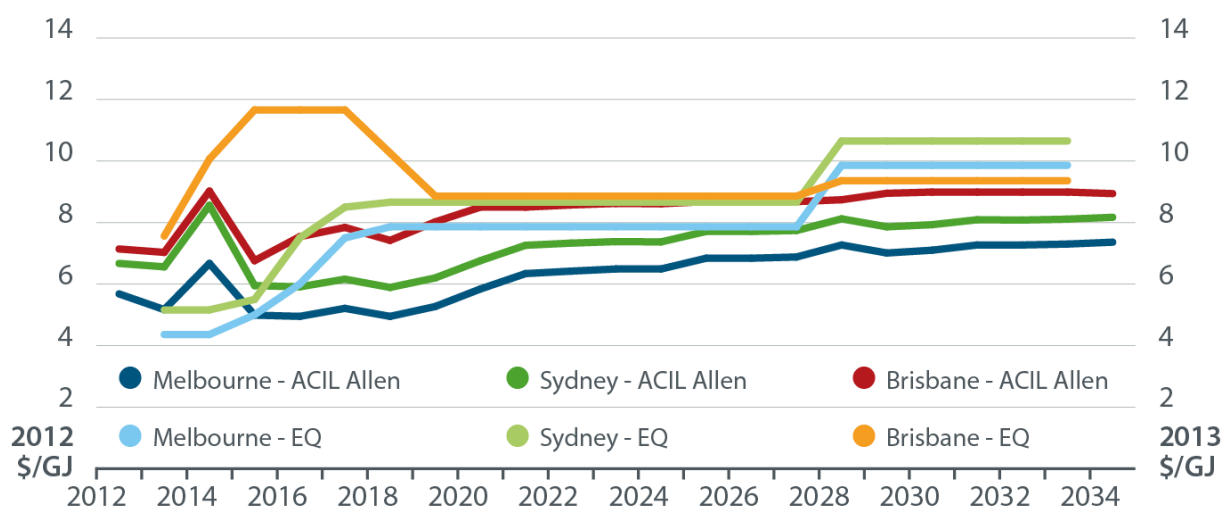
Note: ACIL Allen is the base scenario and is plotted on the left. EQ is EnergyQuest's $95 JCC scenario and is plotted on the right.

Source: BREE (2013d, citing ACIL Allen 2013 and EnergyQuest 2013a).

5.7 Alternative market models

At various stages of Australia's gas market reform process, governments have looked to international gas markets – including markets in the United States, the United Kingdom and Europe – to examine opportunities to progress market development. Those markets have unique characteristics, but a common focus is the agenda to improve market efficiency through improved transparency and liquidity. Reforms have focused on enhancing short-term gas and capacity trading markets, increasing liquidity, and providing flexibility for managing risk for participants through a greater range of trading options.

Gas markets across the world are at different stages of liberalisation. There appear to be well-functioning markets in the United States and the United Kingdom and an evolving market in continental Europe, as evidenced by the amount of gas traded compared to physical deliveries of gas. In the United States, the amount of gas traded via the NYMEX futures instrument is, on average, around 20 times the physical daily volume. In the United Kingdom, around 17 times the physical volume is traded, while in continental Europe traded volumes average between one and four times physical volumes (although the Dutch gas trading hub saw traded volumes reach 14 times physical throughput in 2012). Diversity among market participants has also grown as producers, pipeline operators, marketers and customers have been joined by exchange-traded funds and financial institutions, which has deepened market liquidity (Stern 2012: 95, 150).

Global experience shows that both transparency and liquidity will deliver the greatest benefit to consumers, that full transparency is not necessarily required, and that transparency alone does not guarantee liquidity. Implementation can also take time and significant expense, and will vary markedly between countries.

Developing liquidity has been the result of both commercial and market drivers, linked primarily to physical capacity and existing property rights, and government leadership to develop transparency and trading mechanisms. Liquidity is only likely to emerge when there is sufficient confidence in trading mechanisms for players to begin moving away from an exclusive reliance on long-term bilateral contracts.

5.8 Conclusions

There remains a high degree of uncertainty about the key drivers of price outcomes that are exacerbating tensions in the domestic gas market. That uncertainty is partly generated by the current market structure and may lead to inefficient price outcomes that are sustained in the absence of market reform.

Concentration of production, coupled with asymmetrical information and a new market dynamic caused by linking with an international export market, hampers confidence in price discovery. Given these conditions, it seems timely to consider measures that may enhance the market's development of a range of trading options to better manage risk.

A lack of transparency and high levels of uncertainty are not unique to the gas market. Indeed, many markets evolve mechanisms to operate within such constraints. However, a combination of uncertainty, limited competition, potential or perceived scarcity of supply and lack of transparency in the gas market creates the potential for inefficient outcomes. Market reforms to date have gone some way to improving information to the market but may be insufficient to meet future needs in a more dynamic market environment. Significant differences in market expectations emphasise this point.

Given the long-term nature of market reform, it is important to understand the extent (in both size and duration) of periods of tight supply and transition in the market, and which parameters are most important to driving market outcomes. Consideration of these issues is the subject of Chapter 6.

There is also a prima facie case for improving the liquidity and transparency of the market over time. Many steps are needed to achieve market reform (discussed further in Chapter 7), but reform will only be effective if participants have confidence in its outcomes. This requires commitment and leadership from both governments and market participants.

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6. Modelling and empirical analysis

6.1 Overview

Analysis and scenario modelling was commissioned to improve understanding of the interaction between gas prices and supply in the eastern market, and the nature of the current transition. The modelling and related research serves to provide a context for the examination of policy options in Chapters 7 and 8.

Intelligent Energy Systems (IES), in partnership with Resource and Land Management Services (RLMS), were the primary source of advice, and provided independent modelling of gas prices, gas reserves, gas supply and gas demand for the eastern market for a 10-year period from 2013–14 to 2022–23. This chapter describes IES's approach, the data and assumptions on which its model was based, and discusses IES's key conclusions.

Analytical advice purchased from Sinclair Knight Merz (SKM), coupled with a regular major report by Core Energy Group, and AEMO's recently released 2013 Gas Statement of Opportunities were also assessed. While there are limitations in comparability, the different approaches, assumptions and focus of these analyses were used to provide a counterpoint and context to IES's work.

The views expressed in IES's report and other reports, including those of SKM, Core Energy and AEMO, do not necessarily represent the views of the Department of Industry or BREE.

6.2 IES modelling purpose and approach

The purpose of IES's work was to model how the eastern market may respond to possible changes and:

- determine whether gas reserves and production are sufficient to meet domestic and LNG export demand
- determine whether gas transmission pipelines and processing facilities have enough capacity to meet demand and deliver new gas production
- model gas prices at major demand nodes.

This work used IES's Integrated Gas and Electricity Model (IGEM), which uses a least-cost approach that assumes a perfectly competitive market and optimises the development of gas reserves in response to demand over the study period.

IES's model projects indicative gas prices if development constraints are addressed and certainty is provided over the timing and quantum of supply from Queensland CSG developments.

The least-cost approach does not reflect *negotiated* prices in circumstances in which prices are driven above least-cost values by a range of factors, most notably the impact of different commercial behaviour when supply is constrained. The model used costs of production developed by RLMS.

IES's modelling focused on six scenarios developed by the Department in consultation with IES (outlined in Table 6.1). Each scenario has a base, low or high setting for the variables of LNG export timing, CSG reserves development, international LNG netback price, domestic demand, new field development and new pipeline development.

Key inputs included estimates of gas reserves by geological basin, maximum production rates by geological basin, cost of gas development, pipeline tariffs, pipeline capacity limits, domestic and LNG demand, new pipeline and basin developments, rates of field development and LNG netback prices. Data was provided primarily by RLMS and IES, and supported by interviews with a number of stakeholders conducted in the course of this study.

Table 6.1: IES modelling scenarios

Variables	Scenarios					
	Reference case	**LNG low**	**LNG high**	**Low supply**	**High growth**	**High infrastructure**
LNG export timing	Base	Low	High	Base	Base	Base
CSG reserve development	Base	Base	High	Low	High	High
International LNG netback price	Base	Low	High	Base	Base	Base
Domestic demand	Base	Base	Base	Low	High	Base
New field development	Base	Base	Low	Low	High	High
New pipeline development	Base	Base	Low	Low	High	High

Source: IES (2013).

The reference case assumed:

▪ eight LNG trains come online in Queensland over the study period (six currently in construction plus two additional trains)

▪ 60 per cent of 3P CSG reserves are developed to 2P reserves

▪ domestic gas demand (excluding gas-powered generation) grows from 479 PJ in 2013-14 to 543 PJ in 2022-23, based on the 2012 *Gas Statement of Opportunities* planning scenario figures.

▪ New South Wales CSG and associated pipelines are developed to meet demand growth

▪ capacity on some pipelines is increased and some new pipelines are built.

The five other scenarios considered:

▪ low LNG production in Queensland (development of the six trains currently in construction only)

▪ high LNG production in Queensland (development of 12 trains)

▪ low gas production due to supply constraints

▪ strong domestic gas demand growth and associated supply growth

▪ gas infrastructure expansions to meet expected demand growth.

For the six scenarios, the model had three runs: a production cost run, a LNG netback price run, and a maximum daily demand run. The production cost run provided a lower boundary ('least cost') for gas prices at demand hubs in a perfectly competitive market in which prices are based on the cost of supply. The LNG netback run provided an upper boundary for gas prices based on netback prices at the Wallumbilla and Moomba nodes, reflecting the opportunity cost of selling gas into the international LNG market. The maximum daily demand run used maximum demand forecasts at each node to highlight potential infrastructure constraints.

6.2.1 Key findings

IES's modelling of the eastern market showed that there are sufficient conventional gas and CSG resources to meet both domestic gas demand and the gas demand for eight LNG trains in Queensland from 2013–14 to 2022–23. This is consistent with other findings, including by Geoscience Australia, BREE and the Australian Council of Learned Academies, that have demonstrated the potential for both conventional and unconventional gas development in eastern Australia.

Key to this finding is the assumption that both gas resources and associated supporting infrastructure are developed and brought into production in a timely manner. The price of this gas was found to be above historical prices due to the rising costs of production and the influence of LNG netback pricing on the domestic market.

IES's work showed that the price of gas is already moving up the supply cost curve, above historical gas prices, because of rising exploration, development and production costs. It also showed that development will move to higher cost gas resources, raising the price of gas for end users, if the development of lower cost gas resources is constrained by regulatory barriers or other restraints.

6.2.2 Gas pricing

The reference scenario showed a gradual increase in the least-cost price of gas, ranging from approximately $5.40/GJ in Sydney and Brisbane to $6.20/GJ in Adelaide, by 2023 (Figure 6.1).

Only the Sydney hub experienced an easing of prices of about 3 per cent between 2019 and 2021, which was attributed to new gas production commencing from the Gunnedah and Gloucester basins in New South Wales. This new gas has the potential to be supplied at lower cost than gas from other sources due to its proximity to the Sydney market and resultant lower gas transportation costs.

Figure 6.1: Projected least-cost gas prices, reference scenario, production cost run ($/GJ)
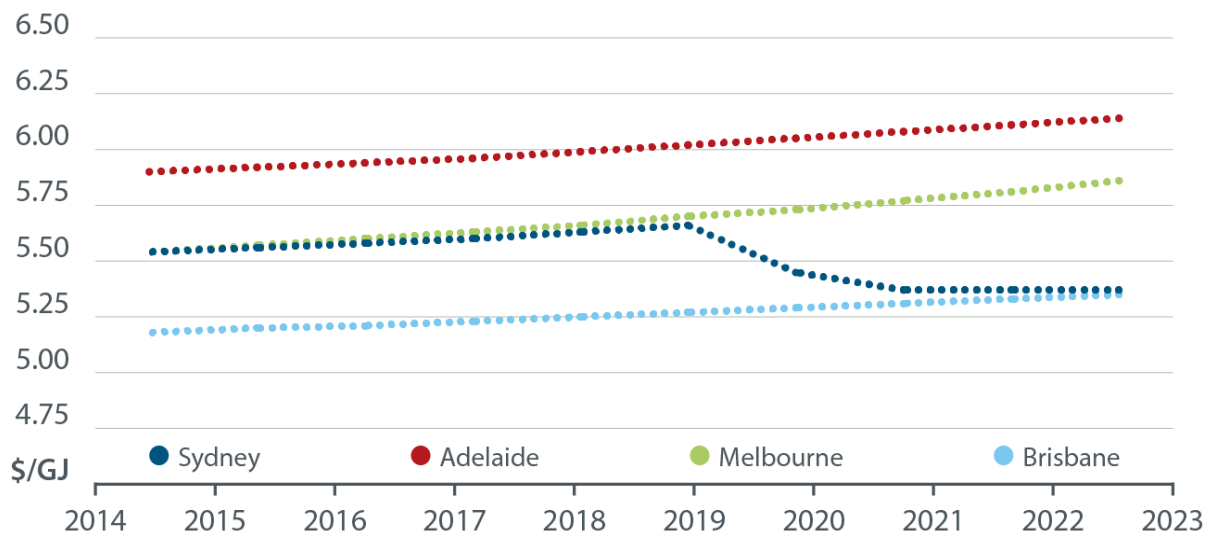
Source: IES (2013).

The LNG netback run was used to test scenarios in which prices might rise above least-cost levels (a more probable scenario). Gas prices in this run (Figure 6.2) ranged from $6/GJ in Melbourne to $11/GJ in Adelaide and Brisbane by 2023, primarily driven by LNG netback price assumptions.

Melbourne, where prices were not linked to LNG netback prices and rose gradually with no fluctuations, was the exception. This was attributed to a steady gas supply from the Gippsland, Otway and Bass basins and the physical constraints on transporting gas from those basins to Gladstone for LNG export.

The large increase in the gas price at the Adelaide hub from 2015 to 2016 ($3.22/GJ, a 56 per cent increase) was a direct result of the reverse of gas flow on the South West Queensland Pipeline so that gas flows from Moomba to the east to supply gas for LNG export. This resulted in the price of gas from the Cooper–Eromanga basins moving to LNG netback prices.

The effect of netback pricing at the Cooper–Eromanga basins was also experienced at the Sydney hub, with a large price increase from 2015 to 2016 (25 per cent, by $1.34/GJ). However, the gas price at the Sydney hub was projected to drop between 2019 and 2020 due to new gas production commencing from the Gunnedah and Gloucester basins.

These price projections should be interpreted with caution. As noted above, the model does not account for circumstances in which it would be possible to set prices above least-cost levels. This includes tight market situations such as, arguably, current conditions, in which there might be the commercial opportunity for suppliers to charge a higher price.

This is particularly the case when interpreting the Melbourne figures. While the LNG netback run gave a proxy for export returns, which would be lower in Melbourne because of the high transport cost from the Bass Strait to Queensland export facilities, in the absence of supply-side competition prices will be more likely to be set at the maximum level tolerable by demand and not by the export opportunity cost.

Figure 6.2: Projected market gas prices, reference scenario, LNG netback run ($/GJ)
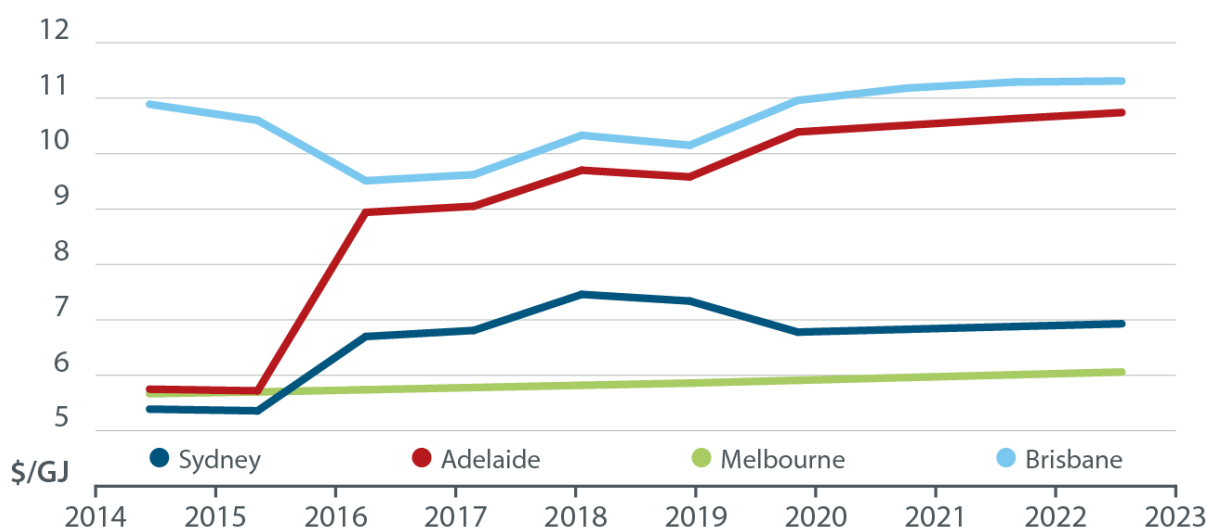
Source: IES (2013).

6.2.3 Reserves

Eastern Australia has significant gas reserves. According to RLMS, at the end of 2012 they totalled 51,401 PJ of 2P reserves, consisting of 44,442 PJ of CSG reserves and 6,959 PJ of conventional reserves. Approximately 38,000 PJ (86 per cent) of CSG 2P reserves and 1,100 PJ (16 per cent) of 2P conventional reserves are committed to the four major LNG projects.

The 2P conventional gas reserves from the Otway and Bass basins were depleted by 2021–22 and gas production from those basins drew from 3P reserves and 2C resources from 2021. Companies are expending considerable resources in further exploration and appraisal to increase reserves and maximise the life of existing infrastructure (pipelines and processing plants). This may lead to the development of new fields in existing basins, such as the Otway Basin.

Modelling also showed that new gas supply from the CSG reserves in the Gloucester and Gunnedah basins in New South Wales would slow the depletion of 2P conventional gas reserves in Victoria (reducing the need for Victorian gas to supply the New South Wales market). New gas pipelines and processing facilities will be required for CSG production to commence from these two basins by 2019.

6.2.4 Supply and demand

The modelling showed that there was sufficient supply to meet expected domestic demand and the demand of eight LNG trains over the study period (Figure 6.3). This was based on the assumed timely development of conventional gas resources and the efficient conversion of 2C CSG resources to production (a five-year conversion time was used).

Most of the gas for the LNG trains was supplied by CSG from the Bowen–Surat basins. Production out of all other basins remained relatively steady.

Figure 6.3: Aggregated gas supply, reference scenario, LNG netback run (PJ/year)
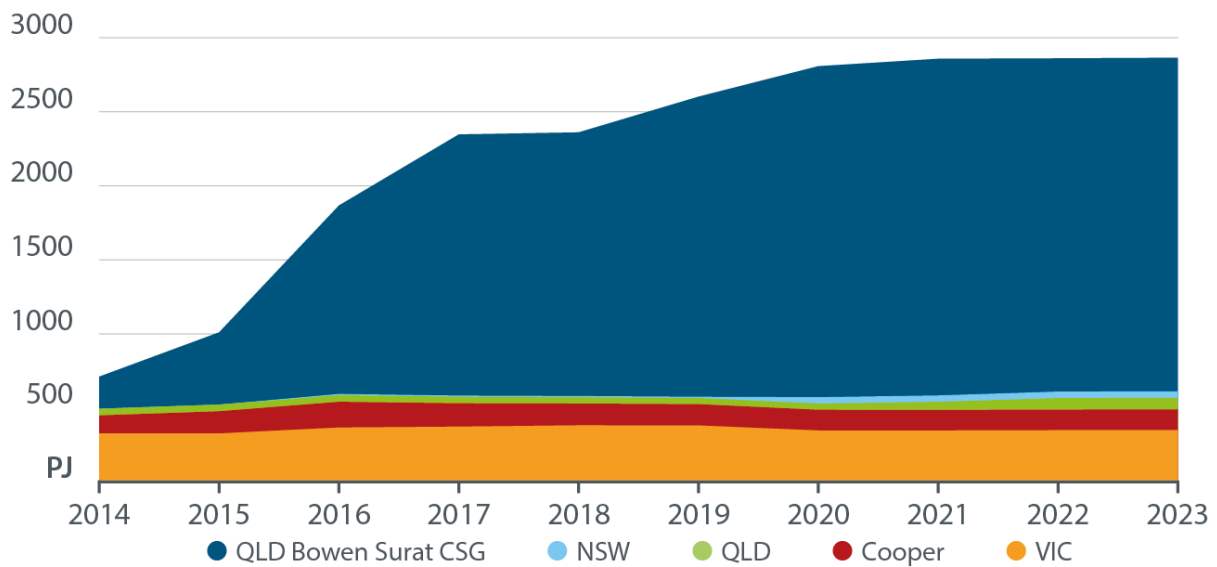
Source: IES (2013).

Demand from gas-powered generation was projected to decrease due to higher gas prices (Figure 6.4). As a result, gas-powered generation played a key role in providing swing supply in the gas market. Gas-powered generation demand fell most in Queensland, where generation capacity was linked to the LNG projects as part of a gas production ramp-up management strategy and then gas was redirected to LNG production.

Figure 6.4: Gas-powered generation demand, reference scenario, LNG netback run (PJ/year)
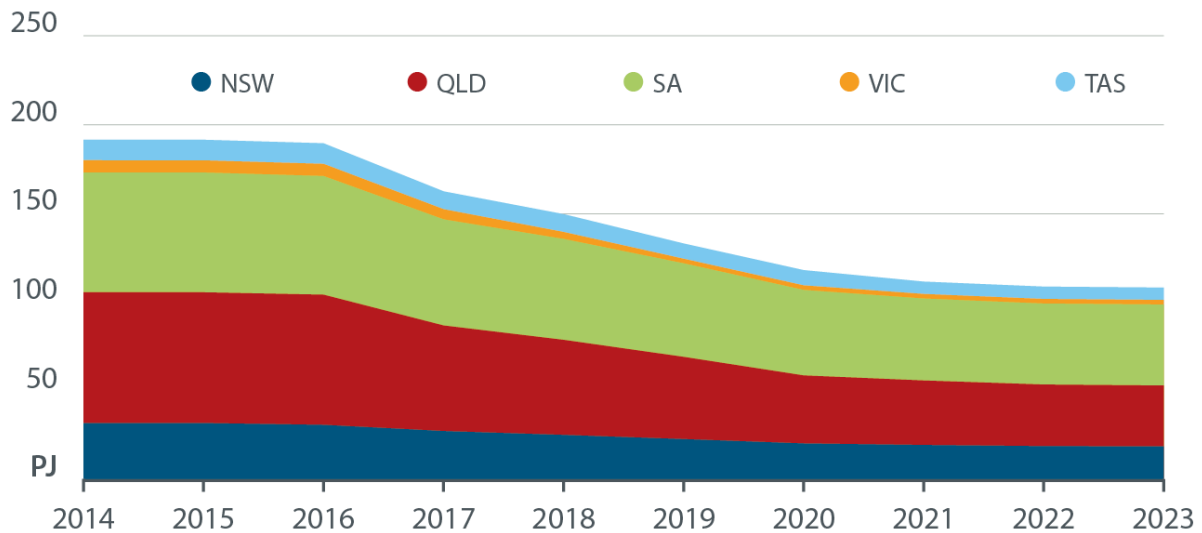
Source: IES (2013).

The overall domestic gas demand profile stayed relatively flat as mass market and industrial gas demand growth was offset by the reduction in gas-powered generation demand (Figure 6.5).

Figure 6.5: Total domestic demand excluding LNG, reference scenario, LNG netback run (PJ/year)
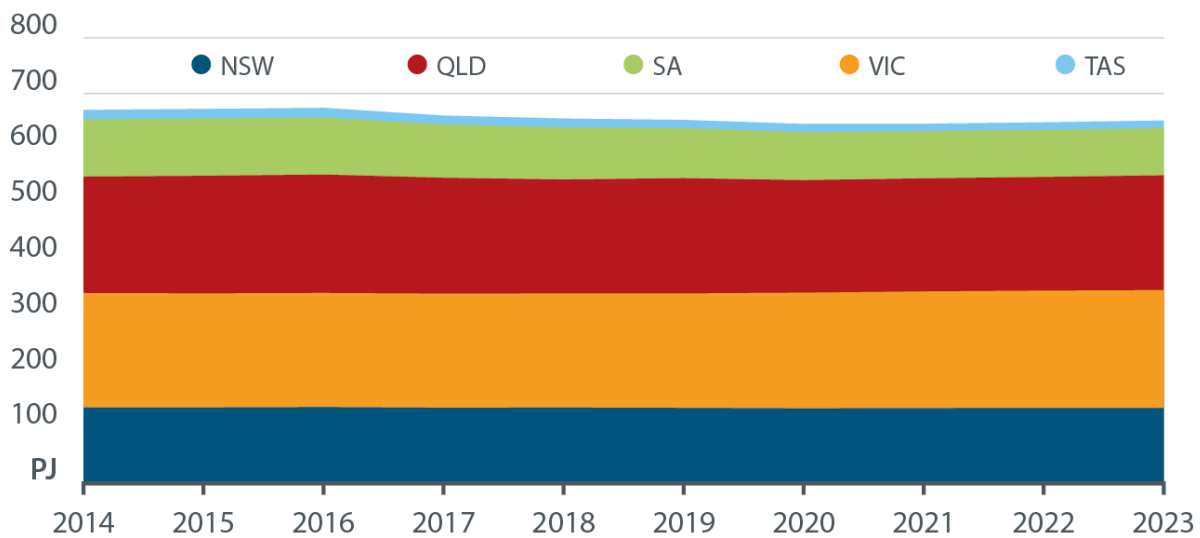
Source: IES (2013).

6.2.5 Pipeline and processing infrastructure capacity

Modelling showed that current and planned upgrades to transmission pipeline and gas processing capacity were sufficient to meet annual demand over the study period, although the market's ability to meet demand could be reduced if some of these upgrades did not proceed. Pipeline expansions assumed to proceed in the study period were:

- Queensland Gas Pipeline (Wallumbilla to Gladstone)
- South West Queensland Pipeline, west to east flow (Moomba to Wallumbilla)
- South West Pipeline (Port Campbell to Melbourne).

Pipelines assumed to be built during the study period were:

- Queensland to Hunter Pipeline (Wallumbilla to Gunnedah to Newcastle)
- Stratford to Hexham Pipeline
- Lions Way Pipeline (Casino (Clarence–Moreton Basin) to Ipswich)

Maximum daily demand modelling highlighted potential peak-day constraints in Queensland within the next 10 years on the Carpentaria (Ballera to Mt Isa) Gas Pipeline and the North Queensland (Moranbah to Townsville) Gas Pipeline, if the capacity on these pipelines was not increased.

6.3 SKM modelling

SKM's Gas Market Modelling report modelled the eastern market from 2013 to 2030 using its Market Model Australia – Gas (MMAGas) model. This model represents the market for new long-term upstream (wholesale) gas contracts and uses an algorithm that maximises profits for gas producers, taking into account production and transmission pipeline costs and levels of competition. A particular focus of the SKM analysis was the extent to which gas currently dedicated to the domestic market remains so, or is available to be "diverted" to serve export contracts.

The model had three scenarios involving the following assumptions:

- base case: eight LNG trains come online by 2019
- high LNG case: 13 LNG trains come online in the study period (eight operating by 2019 and an additional five LNG trains commissioned at regular intervals from 2021) and LNG netback levels are relatively high
- low LNG case: only the six LNG trains currently under construction are built; LNG netback levels are relatively low.

Key inputs included:

- 2P gas reserves and resources available for development
- gas production costs
- existing gas contract volumes
- gas transmission network structure and costs
- gas demand projections.

New upstream gas contract prices were projected based on two alternative assumptions:

1. All existing contracts remained dedicated to the domestic market ("no diversion" scenarios).

2. All gas not contracted directly and indirectly to end users was available for diversion to exports and further new upstream contracts were required for the domestic market ("diversion" scenarios).

SKM's key findings are summarised below.

Projections for assumption 1 (no contract diversion) showed new contract prices steadily rising in all scenarios until LNG development stopped or slowed (that is, until 2017 to 2020; Figure 6.6). Similar price patterns were shown in both Queensland and southern states, owing to the interaction of demand and supply from north to south.

Figure 6.6: New eastern Australia gas contract prices, with existing contracts remaining dedicated to the domestic market ($/GJ, weighted average, delivered, $2013 real)
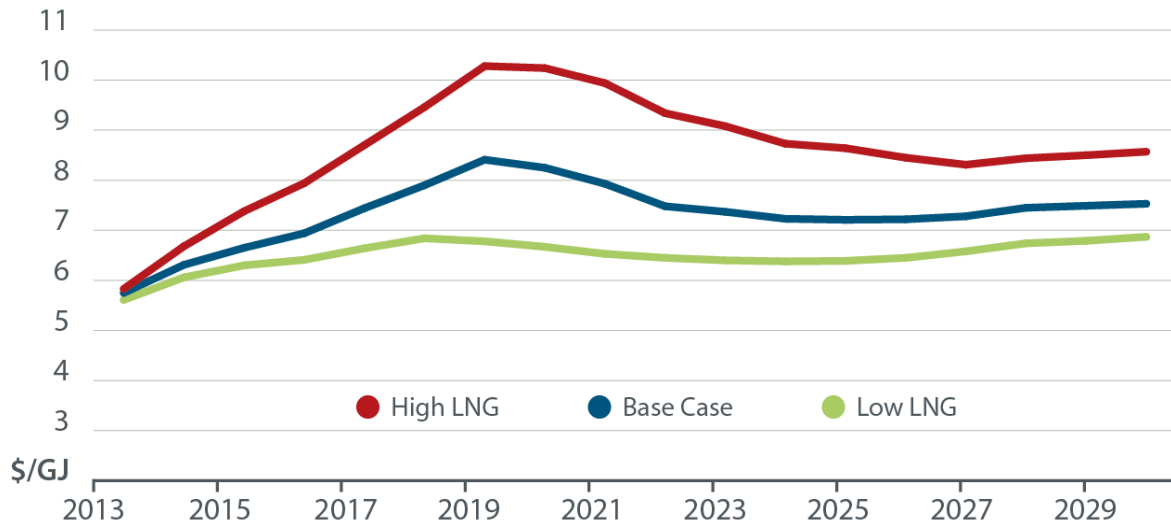
Source: SKM (2013).

Projections for assumption 1 showed the average price of gas in ongoing and new contracts rising more slowly than the average price for new contracts, reflecting the progressive addition of new contracts, with major contract replacement in 2017 and 2018 (Figure 6.7). If these average prices were passed through to the wholesale cost of gas in retail contracts, end users were protected from most of the price rise until 2017. This analysis assumed that the prices of ongoing contracts were fixed in real terms.

Figure 6.7: Average ongoing and new contract prices, with existing contracts remaining dedicated to the domestic market ($/GJ, weighted average, delivered, $2013 real)
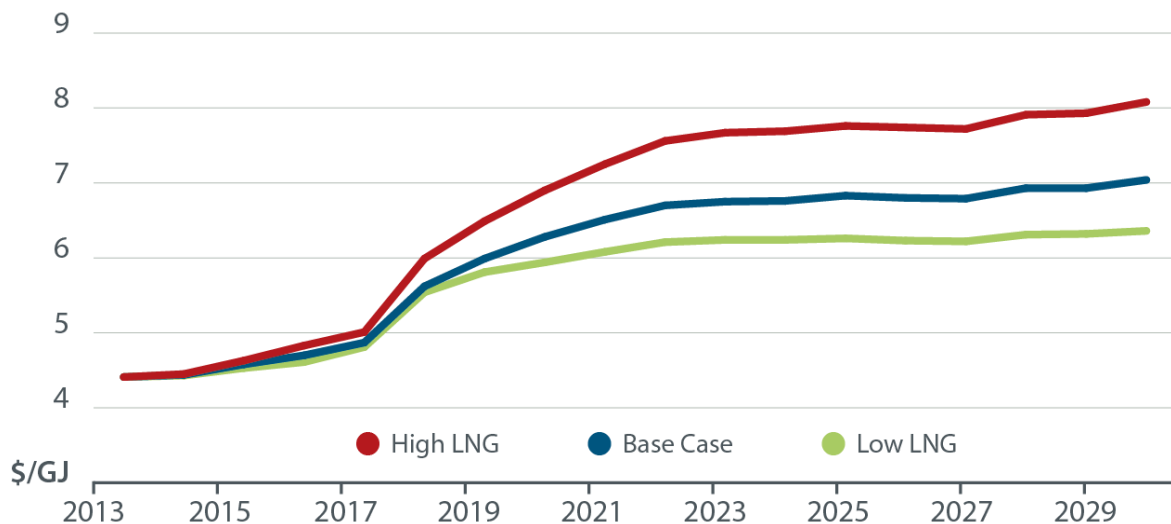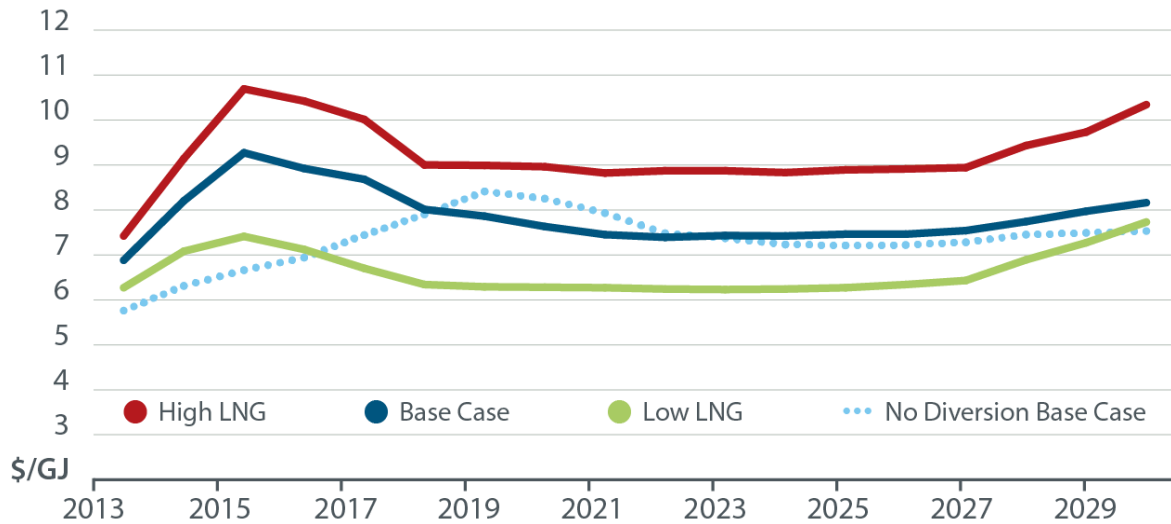

Source: SKM (2013).

However, SKM noted a recent report by the Australian Industry Group (2013) suggests that retail prices will rise significantly from 2014, as if the price protection from ongoing contracts were not there. This outcome could be simulated by projecting prices under assumption 2 – that all gas not contracted to end users was available for diversion to exports and further new upstream contracts were required for the domestic market. With this assumption,

domestic prices for both new contracts (Figure 6.8) and average contracts (Figure 6.9) rose earlier, more quickly and to higher levels, and new contract prices fell three to four years earlier, than with the 'no diversion' assumption.

Figure 6.8: New upstream contract prices with high off-contract gas diversion to LNG ($/GJ, weighted average, delivered, $2013 real)

Source: SKM (2013).

Figure 6.9: Average existing and new contract prices with high off-contract gas diversion to LNG ($/GJ, weighted average, delivered, $2013 real)
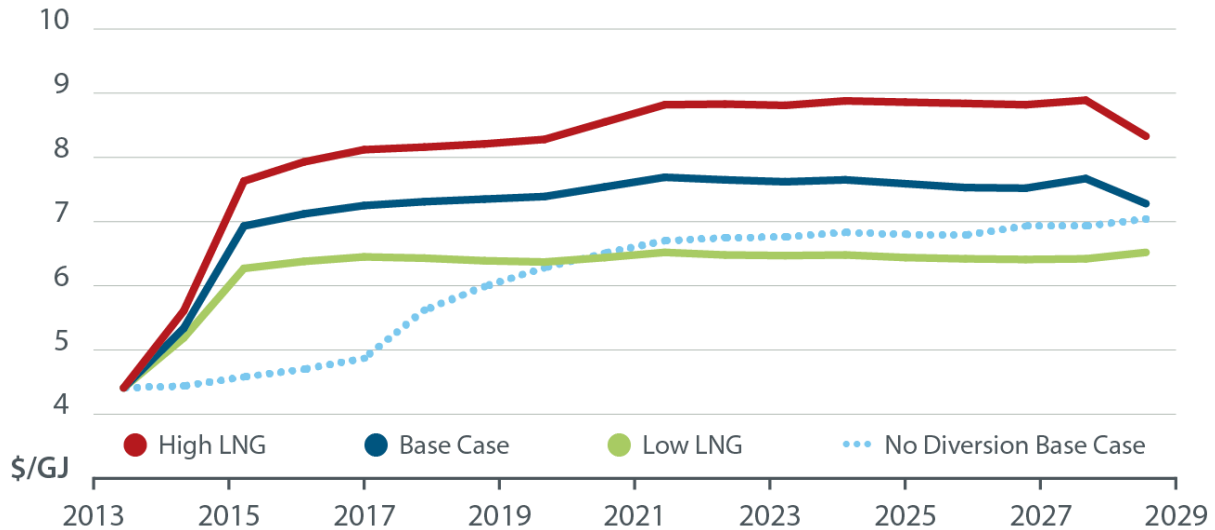
Source: SKM (2013).

Overall, the price ranges in SKM's projections for the high contract diversion to LNG assumption seem reasonably consistent with recent media reporting of contract prices.

6.4 Other modelling

6.4.1 Core Energy Group

Core Energy's *2013 gas, power and LNG outlook to 2033* derives demand for each state and market segment based on a blend of top-down and bottom-up techniques. Customer level contract profiles (parties, volume, term, price) are then used to determine uncontracted demand and uncommitted supply. Uncontracted demand is assumed to be met based on the lowest cost delivered supply - taking into account factors such as the strategic behaviour of parties, competition, ability to swap/hedge and load factor. Core Energy's key findings are summarised below.

Core Energy found that by 2020 the Queensland LNG projects would require around 1,700 PJ per year of gas in the reference scenario. Domestic demand was projected to fall from 705 PJ in 2012 to a low point of 575 PJ in 2018, due to a reduction in gas-powered generation demand (235 to 140 PJ) and industrial demand (293 to 260 PJ). Domestic demand was then projected to be flat, increasing only 4 PJ to 579 PJ by 2033 (Figure 6.10).

Figure 6.10: Projected eastern Australia annual gas demand by segment, reference scenario (PJ)
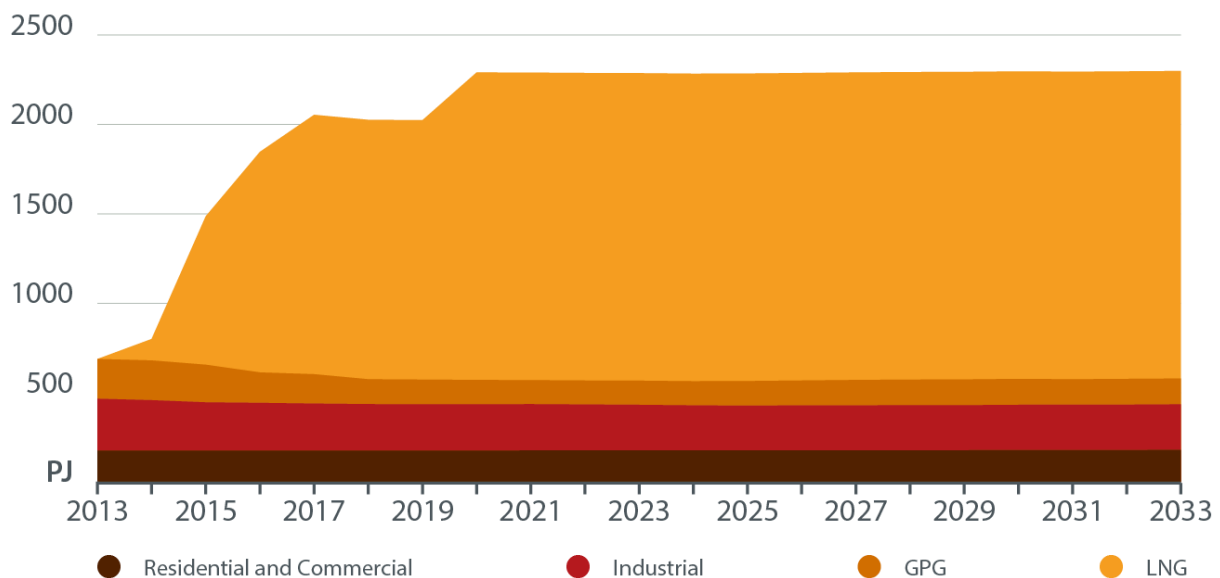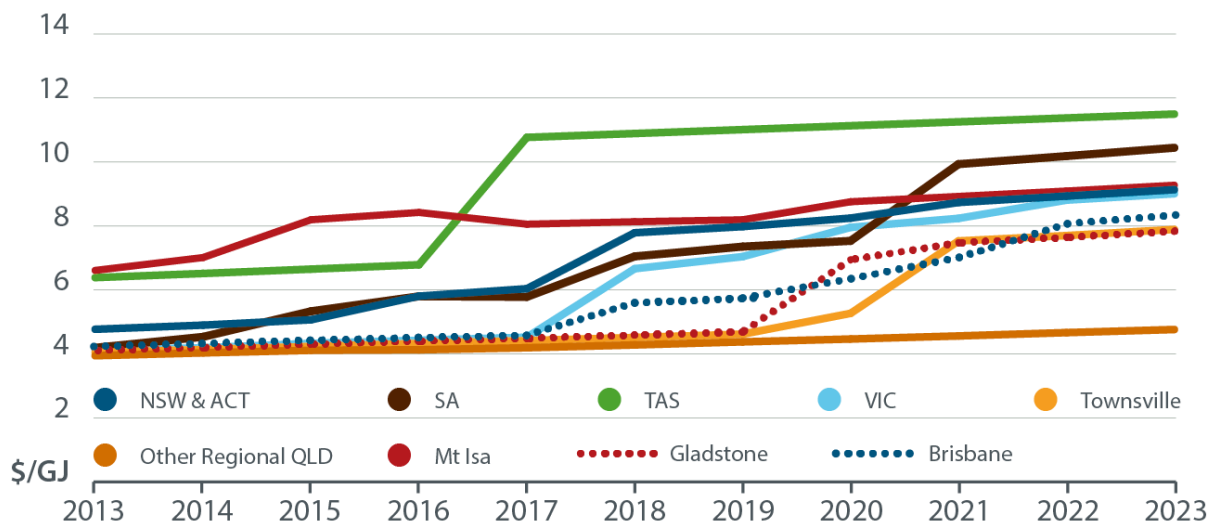

Source: Core Energy Group (2013).

Core Energy concluded that there would be adequate 2P reserves to satisfy domestic demand projections to 2033, although there could be localised 2P depletion before that date in the Otway, Bass, Cooper and Gippsland basins. However, for domestic customers who have contracts maturing over the next five years, supply options would be restricted by the majority of Surat–Bowen CSG reserves and significant Cooper Basin reserves being committed to LNG production, as well as the slow progress to develop CSG in New South Wales. Core Energy noted the Gippsland Basin Joint Venture was the only party in the southern states with larger scale uncontracted 2P reserves, giving it increasing market power.

Gladstone LNG was the only LNG project expected to be short on reserves to meet existing contracts, but Core Energy found that all the Queensland LNG projects would face challenges in developing reserves through to 2020 and were likely to source gas or swap gas from Queensland CSG fields and/or the Cooper Basin not currently earmarked for export. That volume could be up to 5 per cent of total committed demand (78 PJ per year) and would place upward pressure on contract prices.

Core Energy found that the costs of new supply were projected to increase from historical prices of $2–3/GJ towards a long-run marginal cost of $6–8/GJ (2013 dollars) for new supply beyond 2017. This was due to the maturity of conventional gas fields, a move to higher cost CSG fields to meet LNG commitments, and a move to shale and tight gas to meet future demand. Core Energy projected that new contract prices would rise from a weighted average of $4/GJ ex-field for existing contracts pre-2016, to up to $8.50/GJ ex-field beyond 2018 in line with LNG netback prices. Figure 6.11 shows Core Energy's projected delivered price at each demand centre.

Figure 6.11: Projected weighted average delivered contract gas price, real $2013, reference case ($/GJ)

Source: Core Energy Group (2013).

6.4.2 Gas Statement of Opportunities

AEMO's 2013 Gas Statement of Opportunities modelled demand and the adequacy of reserves and infrastructure over a 20-year outlook from 2014 to 2033. It considered several scenarios based on assumptions about the capacity of key pipelines and the priority given to gas supply for LNG export.

The modelling found potential gas supply shortfalls in New South Wales and Queensland, under some scenarios, if facilities currently used for domestic demand were used to supply LNG demand. The Queensland shortfall was projected to be up to 250 TJ per day by 2019 if there was no additional investment in gas supply, pipeline, processing or storage infrastructure.

If gas production in Queensland and South Australia was prioritised for LNG export, the modelling showed flow-on effects for New South Wales, including a potential gas shortfall of 50–100 TJ on peak winter days by 2018 (Figure 6.12). The analysis indicated that new production from the Gloucester Basin and a new storage facility in Newcastle might not completely alleviate the shortfall.

**Figure 6.12**: New South Wales gas supply adequacy
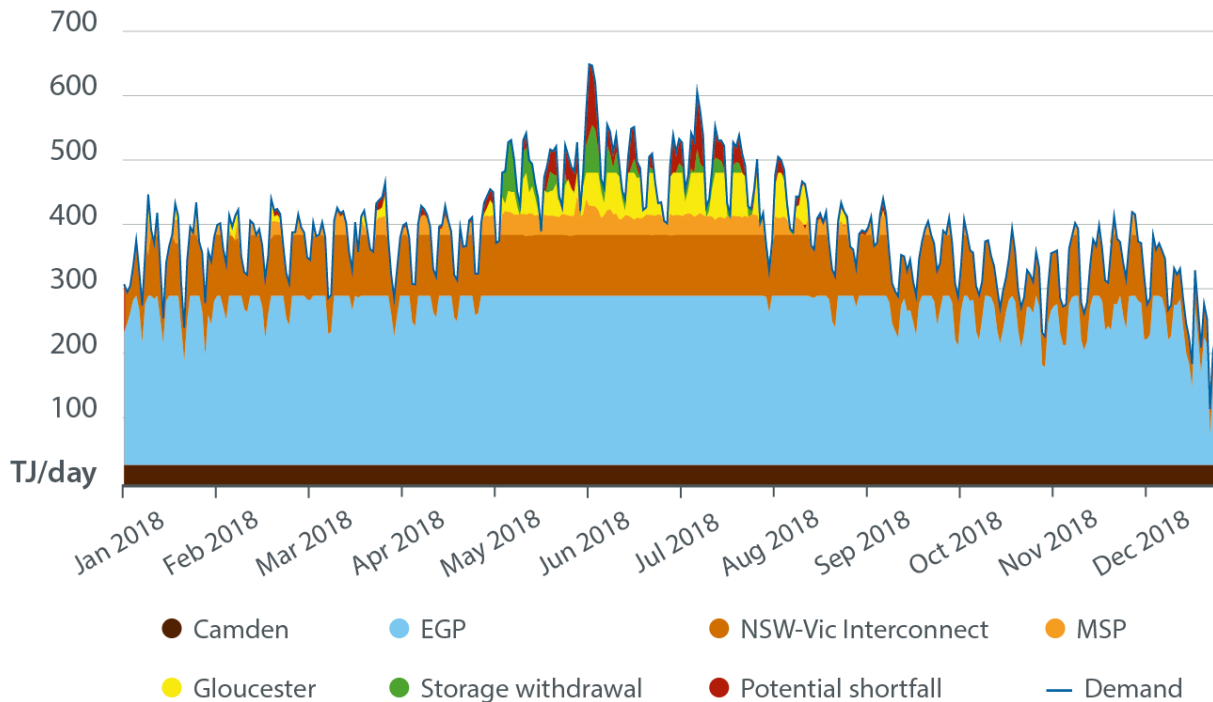
Source: AEMO (2013).

AEMO's modelling showed that combined gas reserves and contingent resources were sufficient to satisfy projected gas demand for the next 20 years. Existing 2P reserves are sufficient until 2020, by which time the Denison Trough (Bowen Basin) and the Otway Basin begin to deplete. Beyond this, 2P conventional reserves are depleted from 2025 in the Cooper and Bass basins and in the Gippsland Basin from 2026, if no further resource development occurs.

AEMO's modelling also projected a potential supply shortfall if no further infrastructure development occurred and/or there was difficulty converting some resources to 2P reserves (Figure 6.13). This highlights the need for continued infrastructure investment and exploration for new supplies of gas.

Figure 6.13: East coast gas production profile
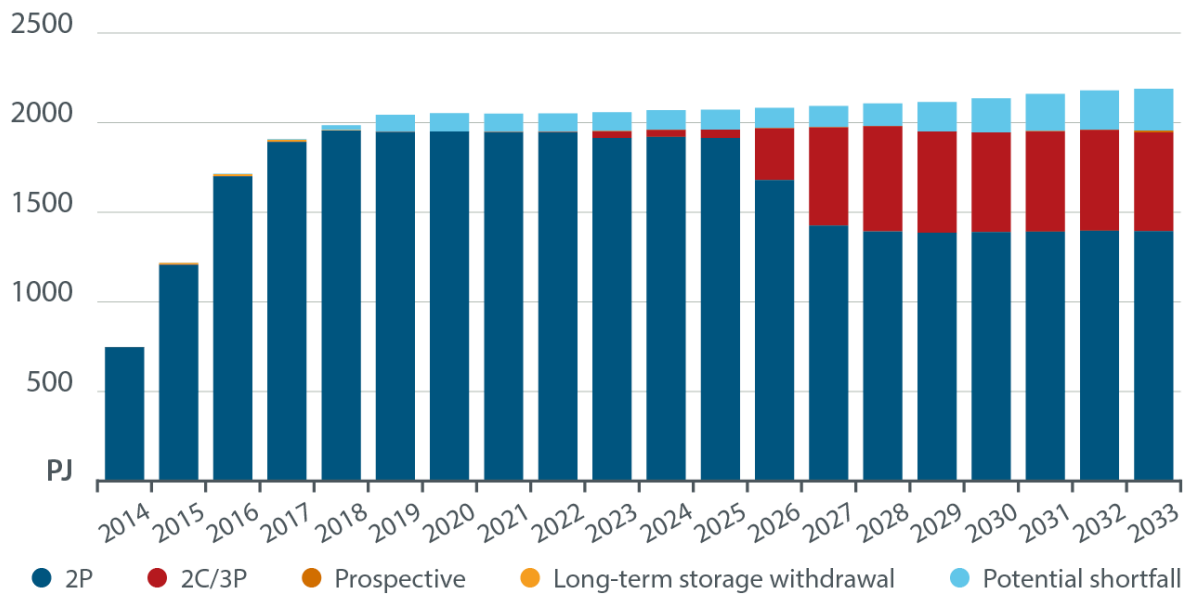
Source: AEMO (2013).

6.5 The Western Australian market

While the eastern market is this study's main focus, the study's terms of reference also required a consideration of the Western Australian gas market. IES provided analysis for Western Australia, which is summarised in this section, as part of the modelling commissioned for this study (Study on the Australian Domestic Gas Market, Chapter 13; IES 2013).

6.5.1 Market size and structure

The Western Australian gas market is a stand-alone system. In 2012, the state's gas production was 1,458 PJ, representing 62 per cent of Australia's total gas production of 2,352 PJ. Of that, 365 PJ (25 per cent) was used by the domestic market, providing about 55 per cent of the state's primary energy consumption. LNG production (16.1 Mt in 2012) used 1,093 PJ of gas.

Western Australia has extensive offshore conventional gas resources in the north-west and north, which are the main sources of the state's gas production. There are relatively small offshore conventional resources in the south-west that support a small amount of gas production. Western Australia also has significant unconventional gas resources in the north-east, which are in the early stages of exploration.

Western Australia's domestic market is dominated by industrial demand, and eight gas users, covering the mining, minerals processing and power generation sectors, account for over 90 per cent of domestic gas consumption. On the supply side, 98 per cent of domestic gas is supplied by two gas producers from the offshore Carnarvon Basin.

With only a handful of players, and the bulk of domestic gas traded through bilateral contracts, Western Australia's domestic gas market could be characterised as having limited competition.

The Western Australian Government imposed a domestic supply obligation on the North West Shelf Joint Venture when that project commenced operations in 1984. In 2006 it introduced its Domestic Gas Reservation Policy, which requires future LNG proponents to reserve up to 15 per cent of production for domestic supply to the Western Australian energy market, in exchange for access to state land for processing facilities. The policy allows for negotiations between buyers and LNG proponents on a case-by-case basis. The policy does not apply to facilities in Commonwealth waters (such as floating LNG installations).

6.5.2 Gas prices

The Western Australian domestic gas market's transition to LNG-linked prices is similar to the transition occurring in the eastern market. For the initial domestic gas supply agreements spanning 1984 to 2004, the gas price remained stable at about $2.25/GJ. Contract gas prices have risen steadily since 2005, and recent new contracts are reported to be in the $5–6/GJ range. Estimates of domestic contract prices over the next decade range from $6/GJ to $9/GJ, depending on economic growth and gas demand.

6.6 Conclusion

IES modelling showed that there were sufficient conventional gas and CSG resources and gas production to meet domestic demand and the demand of eight LNG trains from 2013–14 to 2022–23. However, in the absence of major new discoveries, 2P conventional gas reserves from the Otway, Bass and Cooper–Eromanga basins were substantially reduced by 2023. AEMO reported similar results in its 2013 Gas Statement of Opportunities.

Exploration and development of new gas resources will be required during the study period to ensure that there is sufficient gas production to meet demand after 2023. Significant ongoing exploration activity for shale/tight gas resources in the Cooper Basin suggests that the value of this resource is likely to grow over the next 10 years.

Both IES and AEMO concluded that the expansion of some pipeline capacity and continued reserves development will be needed to ensure that new gas production occurs in a timely manner. Delays in the exploration and development of gas resources could affect the timing of reserves becoming available to the market and ultimately the price of gas as supply tightens.

IES's least-cost modelling showed that gas prices at demand hubs are fundamentally dependent on production and transportation costs from the different gas-producing basins. The modelling also projects that least-cost gas prices are likely to rise significantly in response to demand for the LNG export market, as the lowest cost resources would be depleted more quickly than they would if LNG production did not occur.

IES's modelling also showed that diversifying gas supply to a demand hub may decrease the price of gas, where there is a competitive market. This was projected for the Sydney hub with new CSG gas production commencing from the Gunnedah and Gloucester basins in New South Wales. New gas supply from those reserves would also increase the life span of 2P conventional gas reserves in Victoria.

IES noted that its least-cost approach is not representative of gas prices if there is some degree of market power. SKM's model considered the commercial behaviour of suppliers where they have an opportunity to command a gas price in excess of least cost. SKM projected gas prices peaking at around $9/GJ ($2013) in 2015 on the assumption that existing contracts are diverted to LNG producers, compared to around $8/GJ in 2019 when there is no contract diversion.

Core Energy projected new contract prices to rise to $8.50/GJ ($2013) ex field beyond 2019 in line with LNG netback prices, and the cost of new supply to increase from a current weighted average of $4/GJ ex field towards a long run marginal cost of $6 to $8/GJ ($2013) beyond 2017.

Overall, these projections of the wholesale gas market, as it transitions to linking to LNG export prices, provide a useful context for and insights into how the eastern market may operate. Policy options relevant to these observations are discussed in Chapter 7.

7. Policy options

7.1 Context

Australia's economic interest is best served by an eastern gas market that continues to evolve in ways that ensures all participants within the gas supply chain from explorers and producers to consumers are receiving the best value from available gas resources. All indications are that there are sufficient gas resources for both domestic and export requirements. For gas consumers, the adequacy of gas supply and upstream competition in a well-informed market is key to achieving acceptable outcomes. For gas producers, the removal of barriers that may unnecessarily constrain their ability to explore for, develop and supply gas is key. Well considered policy and regulatory certainty is important for all in the sector.

As this study highlights, the linking of the eastern market to the LNG export market is presenting a number of challenges with the potential for significant adjustment in various sectors. Notwithstanding these challenges, the policy options proposed for consideration by government in this chapter are aimed at increasing the likelihood that the market continues to operate and perform well now and into the future.

It is not surprising that there has been considerable debate about whether the current tightness in the market is a sign of a 'price problem' or an 'availability problem'. In practical terms, it is difficult to separate the two, but it is clear from the discussion in this report that there are sufficient gas reserves in the ground, and that the question is primarily one of the timing of production against (mostly export) demand.

The presence of increasing production costs, and the consequence of effectively linking to a higher priced international market, is expected to drive domestic prices up. The difficulty for the eastern market is the speed and scale of new demand entering the market and uncertainty about the supply response.

The policy imperative is to ensure to the greatest extent possible that the adjustment within the gas market and any policy response from government are not more costly than they need to be. This issue, which essentially relates to the efficiency of the market, should be the primary focus of any policy options. The need to commit to appropriate market reforms and address barriers to bringing on gas supply, therefore, remains central to any policy options.

7.2 Towards transparent prices and competitive markets

A common and consistent complaint made by major users is that the current eastern gas market lacks sufficient competition. This is essentially a reflection of the level of confidence in the price discovery process – where once several offers of supply might have been expected, it appears some users are receiving only one or two 'serious' offers. While those claims are subjective and anecdotal, there appears to be a need to improve confidence in the price discovery process.

Having a large number of competing suppliers in a market the size of the current eastern market may not be a realistic prospect, but it is realistic to pursue mechanisms that improve the level of confidence in prices being discovered in what is an essentially opaque bilateral contracting market. Addressing uncertainty by providing better information about the major drivers of expectations for price, availability and risk would be a necessary (although not sufficient) part of achieving this goal. There would also need to be confidence that the competitive structure of the market provided enough motivation for parties to respond to this information.

Competition in the wholesale market has complex and interdependent drivers. Outcomes are the result of regulatory and commercial decisions ranging from acreage allocation through to mergers and acquisition activity and supply decisions. Upstream supply – that is, gas exploration and production – is a necessary but not sufficient driver of competition in the wholesale market. In particular, competition may also be influenced by infrastructure, as the efficiency of commercially determined or regulated access to pipelines, processing and storage, influence pricing and investment decisions in upstream and downstream markets.

Policy to support competition also quickly confronts the trade-offs between bilateral contracts and more liquid and transparent markets. The latter has been raised frequently as a way for improving the management of uncertainties, price discovery and signals to market participants. However, the long-term bilateral contract market which currently dominates commercial arrangements – despite being opaque – has historically also been of significant benefit to buyers and sellers in managing risk. While there is no simple solution to this trade-off, a recurring theme of policy is the issues associated with informing the market and transitioning from an almost exclusive reliance on bilateral arrangements.

7.3 Choosing policy options

The purpose of this study is to inform debate on gas policy and present a range of policy options for feedback from stakeholders, which will in turn guide consideration of gas policy strategy by governments.

The potential areas for improvement discussed in previous chapters provide a useful set of signposts for the types of policy options that might be appropriate for mitigating constraints and improving the market's ability to respond to emerging price signals. Each potential policy option will have different costs and benefits for participants which would require further consideration and analysis.

7.3.1 Targeting policies

Policies addressing the costs of transition should target the likely sources of problems. This report highlights the potential for the cost of transition to be higher than necessary due to the structure of the market, asymmetric information and uncertainties about the supply and price of gas.

While the underlying conditions that give rise to this possibility may have been a feature of the gas market for a long time, they have historically been of limited consequence. Even now, whether or not adjustment problems are likely to be transient or permanent is also unclear. However, in the current market context there is considerably less reassurance that existing arrangements are fit for the purpose of managing risk for all market participants. There are likely to be many potential sources of adjustment problems in the eastern market, which may relate to:

- the extent to which LNG projects are 'short' and drawing gas from the domestic market to meet contractual commitments
- inadequate market information to support efficient price discovery and investment
- the structure of the supply side of the gas market, the ability of supply to respond to price signals and any barriers to such a response
- a gas market heavily reliant on long-term bilateral contracts with insufficient liquidity and depth and an absence of secondary commodity and transport markets
- how demand will respond to higher gas prices, particularly the effect of higher prices on demand from large industrial users
- limited mechanisms for market participants to manage supply and price risks and the potential for risks to be transferred to sections of the economy with limited capacity to manage them
- access to, and pricing of, downstream infrastructure
- limited lines of accountability and governance for market, reform and regulatory issues, particularly those that cross jurisdictional boundaries.

Of these issues, the analysis in this report suggests that limited information and transparency in the presence of significant structural change, and limited tools for risk management, are likely to be among the most significant sources of adjustment difficulties confronting the market in (at least) the short run.

7.3.2 Options and approach

In the shorter term, market outcomes are largely fixed, policy options are limited and the costs and benefits of interventions are uncertain. Therefore, the focus in the short run could be on mechanisms that address inefficiencies created by information asymmetry in the market and on the removal of unnecessary regulatory impediments to new gas supply.

Over time, there is the potential to improve how the market will adapt to future changes. Governments could therefore move now to improve information dissemination to inform a further necessary and ongoing reform agenda. The reform agenda could seek cooperative contributions from the upstream sector, gas retailers and gas users, primarily to balance improving information from gas producers with facilitating investment. This should leverage work already commenced through the SCER, be progressed in consultation with industry and include focused work based on agreed principles for reform. There should be an emphasis on improving price discovery in the wholesale market, including mechanisms to provide increased visibility on key market drivers.

Almost without exception, progressing these potential options (summarised in Box 7.1 and discussed in more detail following) would require a partnership between – and commitment from – the Australian Government, states and territories. For completeness, a range of non-market interventions that have been subject to active public debate recently, in particular gas reservation and export controls, are also discussed. This chapter also includes a discussion on implementation and governance initiatives that are relevant to considering how these policies might be progressed.

Box 7.1: Summary of options for government consideration

I. Gas market reform agenda

1. Consider commissioning a review of gas market competition to focus on matters driving wholesale market outcomes
2. Complete current SCER reforms (especially commence Wallumbilla hub and support pipeline capacity trading)
3. Agree a forward gas market reform agenda in consultation with stakeholders:
    - develop principles to guide policy on commodity, transportation and financial markets
    - conduct specific reviews on the direction and structure of the existing trading and related financial markets

II. Promote gas supply competition

1. Address regulatory impediments to supply
2. Improve title administration and management
3. Jointly facilitate priority gas projects
4. Improve access to and cooperation on pre-competitive geoscience

III. Improve commercial and regulatory environment for infrastructure

1. Improve information to markets and regulators on pricing and utilisation of infrastructure
2. Review suitability of carriage models for pipeline regulation
3. Consider support for infrastructure feasibility studies
4. Enhance capacity trading and develop roadmap and evaluation process around future development of pipeline capacity trading

IV. Market data and transparency

1. Improve information to markets on CSG delivery risks
2. Improve planning and transparency mechanisms such as the Gas Statement of Opportunities and Bulletin Board, and industry initiatives (e.g. price indices, pipeline information)

V. Role for non-market interventions?

1. Reservation policy and national interest tests- should these be ruled out?

VI. Governance and Implementation Issues

1. Improve gas market governance – better data and analysis of gas market issues, better monitoring and supervision of market - particularly of cross-jurisdictional issues
2. Develop clear accountability timelines and protocols for SCER and institutions and update the Australian Gas Market Development Plan

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7.4 Gas market reform agenda

Australia has been reforming its gas markets for more than 20 years through joint government initiatives, including through the Council of Australian Governments (COAG) and industry-led agendas. For example, in response to the 1993 Hilmer report on National Competition Policy, COAG led the removal of barriers to interstate trading in gas, oversaw the establishment of the National Gas Code (which provided for third-party access) and began the transition to full retail contestability in electricity and gas markets.

More structural changes resulted from the Parer review in 2002, when in 2003 COAG agreed to aggregate the discrete jurisdictional governance arrangements. These changes were designed to create efficiencies by centralising rule-making, regulatory decision-making and enforcement, market operation and planning through the creation of the Australian Energy Market Commission (AEMC) and the AER.

To date, gas market development in the eastern market has focused on the downstream sectors. An incremental approach has been taken to improving the operation of transmission and distribution networks. This has involved addressing competition and access issues, instituting nationally consistent regulation regimes and promoting more efficient investment. The upstream sector has generally not been the focus of reform in the eastern market, as gas supplies have continued to be developed without government intervention.

A key recent example of industry-led gas reform is the Gas Market Leaders Group, which was tasked to develop the National Gas Market Development Plan for the Ministerial Council on Energy in 2006. The purpose of the group was to help achieve the Ministerial Council on Energy's objectives for a 'competitive, reliable and secure natural gas market delivering increased transparency, promoting further investment in gas infrastructure and providing efficient management of supply and demand interruptions'. The National Gas Market Bulletin Board and Gas Statement of Opportunities, which arose from that process, were designed to provide additional gas market information and improve decision-making. The initial concepts for the STTMs in New South Wales and South Australia were designed to provide transparent price signals, enable the participation of all major gas users, efficiently price congestion on the system, and facilitate secondary trading.

At times governments will need to take a leadership role in policy development and reform. Care must be taken when deciding the most effective approach to introducing reforms. Properly understanding the needs and incentives of market participants is important for planning and implementing successful policy changes. While the experiences to-date of consensus-driven policy development have been useful, they do reflect the needs and interests of incumbents, and for that reason may be limited in scope and ambition.

Information transparency is important not only to inform the decision-making of market participants, but also to inform policy decisions. Information may reveal whether market problems are likely to self-correct or whether government intervention is necessary. If action is required, it can also help with the shaping and sequencing of reforms. Importantly,

effective market reform takes time and the desired outcomes might not be seen immediately, especially where consensus decision making is a significant part of the approach.

Completing existing work streams and commencing work to articulate and develop a forward gas market reform strategy are important first steps. Useful inputs into developing the agenda could include market development analysis by the AEMC, analysis of market design issues and technical expertise on operational management from AEMO, and the regulatory experience of the AER. State-specific gas market reviews, and the technical input of geoscience and regulatory agencies, are also important.

7.4.1 A review of gas market competition

Given the importance of improving competitive conditions and the need to minimise adjustment costs during the current transition, an option for further consideration could be a more in-depth review of competitive outcomes in the market. The review could have wholesale market outcomes as its focus and include factors incidental to those outcomes, such as:

- the market's competitive structure, the significance of barriers to entry (especially the scale of sunk costs) and the potential for anti-competitive behaviour
- transaction costs and information transparency
- investment in and use of infrastructure
- unnecessary regulatory impediments.

While some of these issues could be reviewed independently, a more comprehensive investigation like this could highlight specific areas of focus for the forward reform agenda and the mechanisms to improve information and policy. It could also identify gaps in information and monitoring regimes, and provide recommendations on improving and gathering the detailed information needed to perform robust policy analysis. Given the breadth of issues which feed into wholesale market outcomes, the Australian Competition and Consumer Commission or another body with relevant remit could potentially undertake the review. The recent Victorian Gas Market Taskforce report proposed a similar study and potential terms of reference for the Productivity Commission. Regardless of the mechanism used, the work would be of most benefit if terms of reference and expected deliverables were developed and agreed by jurisdictions.

7.4.2 Complete current reforms

A range of gas market reforms are underway through SCER in accordance with the Australian Gas Market Development Plan (SCER 2012). These reforms are designed to improve the transparency of the gas market and key priorities on the current agenda should be completed.

The principles underpinning the Australian Gas Market Development Plan are highly consistent with the options considered in this report: ensuring that supply can respond flexibly to market conditions and promoting market development. These principles were agreed at the June 2012 SCER meeting in response to the expectation of increased pressures on the gas supply–demand balance. The plan agreed in December 2012 has clear accountabilities and deliverables, and progress against the plan should be reviewed and planned activities updated.

Of particular importance in the current agenda is the completion of the Wallumbilla gas supply hub, a voluntary trading arrangement in Queensland being developed by AEMO in close cooperation with industry. It will improve the price discovery process closer to the point of upstream supply and will also provide additional experience on different aspects of market design and the actual costs and benefits of such trading models. The plan also includes improvements to the reporting of unconventional gas production data, and the *Multiple Land Use Framework* and *National Harmonised Regulatory Framework for Coal Seam Gas*. A summary of the plan is available on the SCER website.

Pipeline capacity trading, which had been considered in a specific sense in the context of the gas supply hub, is a topic of broader relevance to the market. SCER is finalising decisions on a preferred implementation model (see section 7.6.4 of this report), and that work should be completed as a high priority.

7.4.3 Agree on a forward reform agenda

Specifying a forward gas market reform agenda requires consultation with market participants on the need for the gas market to develop over time in response to changing conditions. In this market, strong price signals are needed to support large, lumpy and sometimes risky investments. This means that there will be times when, regardless of any reforms, competition will be low, the inertia of current arrangements will be high, and there will be a reliance on long-term bilateral relationships. The reform goals need to recognise these characteristics.

Some of this challenge in framing the forward agenda was recently considered in the gas market scoping study report of the AEMC (K Lowe Consulting 2013). That work advocated the development of a strategic plan for gas market development to provide a roadmap that avoids suboptimal market development decisions. It also considered that there was a more pressing need to look at the direction of development for the facilitated wholesale markets (i.e. trading hubs) in accordance with some principles for the objectives and evolutionary paths for such markets.

Similar issues were canvassed in the recent Victorian Gas Market Taskforce report. The need for further review work does have merit, although wide-ranging (or outsourcing) reviews of strategy carry with them a risk of being unwieldy without careful definition of scope and purpose.

The initial deliverable in any reform program is arguably a clear articulation of the specific topics of focus, the development of a robust implementation plan with specific milestones, and the gathering of information in support of more detailed analysis. The Australian Government's proposed Eastern Australian Gas Supply Strategy to 2020 and Energy White Paper may be useful opportunities for progressing this work. However, as few such issues are uniquely within the Australian Government jurisdiction, it is likely the implementation task would need to be agreed by and progressed primarily through SCER.

Consider the need for new gas market reform principles

A key positive attribute of past Gas Market Leaders Group reforms, and of the mechanism recommended by the AEMC, is the need to have information, exchange and debate on the forward reform path through an agreed set of gas reform principles. Agreeing on revised principles may be a useful starting point for progressing forward strategy work.

As a starting point for this discussion, the 14 principles in Table 7.2 could be used as the basis for guiding the forward gas reform agenda. Consistent with those draft principles, the emphasis of the reform program should be on building signals that provide market participants with tools to undertake evaluation of market conditions (such as reliable and robust market information). It should also provide confidence to address points of inflexibility and lead to the development of more liquid and transparent markets.

Conduct specific reviews of facilitated markets

In the context of establishing a foundation for a reform strategy, there may be specific research tasks that can be commenced without delay.

The AEMC recently proposed an evaluation of the role of trading markets such as the STTMs, the Victorian Declared Wholesale Gas Market and the Wallumbilla gas supply hub (K Lowe Consulting 2013). The proposed review would examine the mix and location of the trading markets, the types of participants, costs and benefits and develop advice on how the markets might be reformed over time to provide a clear point of reference for price discovery and resource allocation. While too early to review Wallumbilla itself, AEMO is currently developing a wealth of expertise in market design which would be invaluable to such work. The AEMC also proposes consideration of the opportunities for developing financial markets, and for linking financial products to the facilitated trading markets to assist in risk management.

Table 7.2: Potential new gas market reform principles

Purpose	
1	The purpose of gas market reform is to promote efficient gas markets in the long term interests of consumers in accordance with the National Gas Objective (which covers residential, commercial and industrial users, including making LNG).
Long-term signals	
2	The market should provide clear information on long-term supply and demand trends and opportunities to help inform investment decisions.
3	The market should facilitate entry and exit (to supply, demand, retail and infrastructure provision).
Short- to medium-term signals	
4	The market should provide information and develop tools to manage risk and provide more certainty, which can lower reliance on long-term bilateral contracts (such as encouraging liquidity in markets for trading, volume, capacity and forward products).
5	Information on system operations and capabilities at all stages of the gas supply chain should be publicly available and frequently updated.
General	
6	Market participation should incur transaction and compliance costs that are as low as possible.
7	The market should aid price discovery for both long-term contracts and short-term trades.
8	The market (or regulatory processes where natural monopolies exist) should encourage the utilisation of and efficient investment in infrastructure, including pipelines, processing and storage, and discourage strategic and rent-seeking behaviour.
Governance and development	
9	Market regulation should be consistent across jurisdictions, and subject to consistent and well-informed national policy and institutional oversight.
10	Regulators should be independent and empowered by evidence to make informed decisions.
11	Governments should limit their intervention in the market (in particular prices should not be regulated). In the limited circumstances in which reforms require government leadership to overcome long-standing positions, that leadership should be through measured, accountable and consultative processes that do not compromise existing investments.
12	The market should be able to respond to new circumstances through transparent and rigorous institutional market development and rule change processes. Policy and regulatory process should also be clear and well informed.
13	The market should maintain and support effective emergency management processes.
14	There should be closer links between market and upstream regulatory approaches, information sources, issues and institutions.

7.5 Promote gas supply competition

Effective competition is fundamental to a well-functioning eastern gas market. Ensuring effective competition in the upstream sector is complex and must take into account many trade-offs. Any policy changes would require careful sequencing and ongoing monitoring and review. Policy options to support a competitive upstream sector could be targeted towards the areas of increasing the efficiency of tenement management and supply development to maximise diversity of supply sources, and strengthening the role of the AER and Australian Competition and Consumer Commission in regulation.

7.5.1 Address regulatory impediments to supply

The aim of regulating the upstream petroleum sector should be to provide a framework which facilitates exploration and development of petroleum resources while addressing risks to, and ensuring protection of, the environment, human health and worker safety. Actions to address risk should be evidence based, informed by scientific research and commensurate with that risk. A risk management framework that is informed by both the likelihood of an event occurring and the likely consequences of that event, is crucial to effective regulatory responses.

The SCER-endorsed *National Harmonised Regulatory Framework* provides guidance to regulatory authorities in the development of leading practices for CSG development. SCER has also endorsed the final *Multiple Land Use Framework* to enable government, community and industry to effectively and efficiently meet land access and use challenges, expectations and opportunities. The Multiple Land Use Framework is intended to be used where there is potential for land access or land use conflict such as has occurred in some areas of CSG development.

These documents are a foundation for a regulatory regime which provides assurance for communities and certainty for industry in the development of unconventional gas. State and territory governments could continue to work through SCER to ensure that the regulation of CSG is subject to evidence-based leading practice regulation. Lessons from current regulatory uncertainty (community confusion and project delays) could be applied to ensure the regulatory regime for gas development is understood and accepted as further unconventional gas development proceeds across Australia.

7.5.2 Improve title administration and management

Decisions on the release, award and management of oil and gas acreage and tenements rest with states and territories for onshore and coastal waters, and with the Australian Government (in consultation with the states and territories) in offshore waters. There are a number of issues within the management of tenure and the release of acreage areas which can also affect the ability to discover and develop new gas resources.

The release of acreage and allocation of exploration permits should ensure that acreage release for both frontier areas and mature exploration areas have a size which is relevant to any potential production activity. The minimum efficient scale of any tenement varies, but would depend on the prospectivity or likely quality of reserves and distance to existing infrastructure such as processing facilities and gathering pipelines.

Large areas within eastern Australia which have been released for petroleum exploration are "Under Application". While some of the acreage within this category indicates either acreage in transition from release to granted tenure or from an exploration licence to a production licence, reports from companies indicate that there is a significant backlog in assessing applications for both the award and renewal of permits and licences. There are numerous cases of applications being in the assessment process for over three years.

This situation reflects both a lack of resources and suitably qualified staff within some agencies and an overly onerous or prescriptive regime within some title administration processes that slow the assessment and award of acreage. While the Australian Government has transitioned its regulation of the offshore waters to an outcomes focused system, some requirements within state and territory legislation remain prescriptive and subject to detailed assessment which adds little to the effective or efficient development of gas resources.

In addition to efficient and effective administration of petroleum titles, an important objective of acreage management regimes is to provide explorers and producers with the discipline and incentive to commercialise resources at the time where the value to society is highest. To that end, a key task of title management regimes is to ensure 'land banking' does not occur and that the commercialisation of gas resources is not unnecessarily delayed — bearing in mind risk, technical, market and regulatory factors.

It is recognised that there are legitimate reasons for delaying development where reserves are currently uneconomic, technology is unproven or costs are escalating. In particular, the scale and duration of LNG projects requires a higher level of tenure security over a longer-time frame than has previously been required within tenure systems. However, there may be times where a title holder's strategic interest limits the development and supply of gas.

Regulators and governments should also ensure that titles are only allocated to applicants with sufficient technical and financial means, and that surrender provisions (a percentage of the exploration permit or licence) are enforced during the course of tenure over a particular acreage. Inactive titles should be actively pursued by title regulators, with a view to maximising available acreage for other explorers.

There are some cases where additional tenure security is granted in return for additional work obligations or milestones. While there are advantages for governments in ensuring a longer-term work program within exploration acreage, this should be counterbalanced with the risk of attempting to "pick winners" in a competitive exploration environment.

7.5.3 Jointly facilitate priority gas projects

There are particular projects that could have significant implications for market dynamics and increased supply given their potential development timing and geographic location. State and territory governments and the Australian Government should do all they can to assist such projects negotiating regulatory approvals in a timely and efficient manner.

In most jurisdictions there are mechanisms to identify such projects and to facilitate approvals and developments subject to a number of criteria. Where these projects have approvals across jurisdictional boundaries, joint approaches to facilitation – primarily streamlining of approvals processes – could assist in the timely development of gas resources or supporting infrastructure such as pipelines.

For example, CSG developments in New South Wales have the potential to supply more than half of New South Wales' annual gas demand within the next five years if Santos's Narrabri CSG Project, AGL's Camden Gas Project Expansion, Metgasco's Casino Project and AGL's Gloucester CSG Project proceed (see Table 2.5 in Chapter 2).

There are current examples of successful joint facilitation for recent gas projects – such as the joint Australian/New South Wales Government Narrabri Gas Project Technical Working Group. There is also an Australian Government agenda to implement one-stop shops for regulatory approvals. Facilitating key projects through the regulatory process could help to bring new supply to market sooner, while ensuring that the environment is protected and a social license to operate is maintained.

These reforms and ongoing facilitation could be adopted for gas projects which are likely to be able to produce gas within the next five years during the height of the tightness in the market, and ongoing reform should be continued in streamlining regulatory processes as a priority.

7.5.4 Improve access to and cooperation on pre-competitive geoscience

The responsibility for collecting geoscience information is shared between the Australian Government and state and territory governments. Each state and territory other than the Australian Capital Territory has its own geological survey organisation, which is responsible for collecting onshore pre-competitive geoscience information. Geoscience Australia, an Australian Government agency, has prime responsibility for offshore pre-competitive information and mapping activities. It also collaborates formally with its jurisdictional counterparts under the National Geoscience Agreement in gathering and assessing onshore geoscientific data (at national and regional scales).

Conventional gas, CSG and other unconventional gas will play an important role in Australia's future energy mix. Government provision of pre-competitive geoscience information is a proven way to attract investment in resource exploration, especially in more marginal and underexplored areas.

There are opportunities to improve cooperation between Australia's geoscience agencies and the coverage and delivery of pre-competitive geoscientific information to ensure that existing resources are more effectively utilised. A number of state-run programs to fund pre-competitive geoscience activities are close to or past conclusion, including the New South Wales Government's New Frontiers Initiative (2006–2012), the Queensland Government's Greenfields 2020 program (2010–2013) and the South Australian Government's Plan for Accelerating Exploration (2004–2014). Those initiatives have included co-funding onshore drilling, facilitating the transfer of exploration technology and modernising the delivery and management of data.

Despite the provision and quality of Australia's geology, some of Australia's basins are poorly explored and understood. Cooperation between agencies and further investment in pre-competitive geoscience information may improve the knowledge and understanding of resources and geological basins.

7.6 Improve the commercial and regulatory environment for infrastructure

The development of new upstream gas supply and effective competition in wholesale gas markets is heavily dependent on producers and shippers accessing competitively priced upstream infrastructure services. Historically, investment in gas supply infrastructure has been both sufficient and timely and has met the market's needs. The model of long-term bilateral contracts between pipeline operators and shippers that promoted investment to date was founded on a relatively stable domestic market with incremental demand growth and relatively stable prices.

However, as the market transitions to LNG exporting, it is worth considering whether the provision of timely and sufficient infrastructure will continue to be as effective in the future, and whether the commercial and regulatory signals driving infrastructure investment and utilisation remain appropriate. The provision and use of gas supply infrastructure might be enhanced by policy which acts to:

- improve information to market and regulators on the pricing and utilisation of infrastructure
- review the suitability of alternative carriage models for pipeline regulation
- consider government support for infrastructure (such as feasibility studies)
- facilitate the development of capacity trading.

7.6.1 Improve information to markets and regulators on the pricing and utilisation of infrastructure

As highlighted in Chapter 4, the market's development and ability to respond effectively during the current transition period would benefit from additional information on prices and capacity utilisation and availability of infrastructure services. AEMO's annual Gas Statement of Opportunities provides comprehensive information on historical and projected physical gas flows relating to production, processing plant, storage and pipeline infrastructure for planning purposes, but may not be suitable for commercial decisions on access and pricing by users of infrastructure services.

While there is limited information on storage facilities and gas processing is generally vertically integrated with upstream gas production, there may be benefits to the market in having greater transparency in the pricing and utilisation of these services. For pipeline services, information on prices and contracted and available capacity could provide regulators with a better assessment of the market's performance, and be the basis for considering whether a change to regulation of those services is warranted.

Mechanisms to achieve improved market information on prices and access to infrastructure services are broad. A minimalist approach could begin with the voluntary reporting of information. Alternatively, the AER could be tasked with a light-handed monitoring and surveillance role (i.e. collecting and publishing information, with appropriate treatment of commercial sensitivities).

The proposed review of competition issues (see section 7.4.1) could consider the costs and benefits of whether the AER should be given more information-gathering powers and a market monitoring function. If deemed necessary, the information obtained could extend to details of negotiated outcomes between infrastructure service providers and users. The evidence and conclusions that would emerge from the information would better inform the reform agenda.

7.6.2 Review the suitability of carriage models for pipeline regulation

As discussed in Chapter 4, there are several different models used in Australia and overseas for managing pipeline access and pricing. The two models used in the eastern gas market are the market carriage model and the contract carriage model. Each model has strengths and weaknesses that need to be considered in the context of the particular demands of the market and the physical relationship between supply and demand centres.

The majority of the eastern market operates under a contract carriage model. While this model has served to deliver investment in a more stable market environment, it may not be best suited to changing conditions in the market. Potential problems with this model are shippers being reluctant to accept the full risk of a stranded asset and pipeline operators not having incentives to invest in spare capacity, which together may lead to inefficient investment in pipeline capacity.

Open access to infrastructure under a market carriage model also involves trade-offs. While sometimes criticised for providing a weaker signal to investment, a strength of this model is that it may further encourage depth and liquidity in wholesale markets. Whether there is an alternative form of market carriage which could be more widely applied in Australia would require careful consideration and review.

While the evidence does not suggest an immediate problem, given the changes in the eastern market it could be appropriate to review which model will best meet the future needs of the market. This could involve a more substantive and specific review of the alternative carriage models, perhaps by the AEMC in consultation with AEMO.

7.6.3 Consider support for infrastructure feasibility studies

While ultimately the market is best placed to signal and finance infrastructure developments, given the broader wholesale market benefits from infrastructure, from time to time governments consider the viability of infrastructure solutions that can lead to an improvement in the functioning of the gas market. This may include feasibility studies to examine investment in proposals such as:

- the development of critical linkages or common user infrastructure that might promote competition (for example enabling infrastructure at supply hubs)
- the construction of greenfield pipelines to facilitate the development of new reserves, link discrete markets, increase the diversity of supply and strengthen competition in wholesale markets.

Government investment in gas market infrastructure is difficult to justify, and even the net benefits of providing funding for feasibility studies on these types of initiatives are typically difficult to evaluate. However, given the link between infrastructure and future wholesale market outcomes, consideration could be given to whether there are opportunities for government to contribute to assessing the feasibility of important infrastructure projects.

7.6.4 Enhance capacity trading

Under a contract carriage model, the performance of physical wholesale hubs depends on having flexible access to pipeline capacity including on a short-term basis. In the absence of secondary markets for accessing pipeline capacity, the depth and liquidity of the commodity market at a physical hub are likely to be diminished. Therefore, secondary capacity trading can be viewed as a key ingredient in the market's ongoing efficiency. In particular, the co-existence of a mechanism to enable secondary trading of pipeline capacity and a physical supply hub, such as that being implemented by AEMO at Wallumbilla, helps to develop confidence in wholesale market outcomes.

A movement towards transparent secondary capacity trading, the development of innovative pipeline services and shorter term trading of wholesale gas could assist in meeting the ongoing needs of wholesale market participants. In practice, several interrelated changes could be called for, including:

- reducing the reliance on restrictive take-or-pay obligations and modifications to the pricing of physically firm primary capacity in long-term contracts

- moving away from the bundling of pipeline services, and instead offering market participants a more creative range of services that are priced separately from traditional firm forward haul services

- shortening the length of contracts

- using financial mechanisms to manage congestion (that is, compensation for non-delivery), rather than relying solely on physical firmness and incurring inefficiently high costs to minimise the probability of interruption

- investing in uncontracted pipeline capacity.

In principle, many potential benefits can emerge from instituting secondary markets for pipeline capacity. Benefits include improvements to the efficiency of primary contracts for pipeline transport and wholesale market efficiency. This would include increasing the liquidity of physical trading hubs and isolating the underlying commodity value of gas as a reference point for long-term gas supply contracts.[2]

There is limited publicly available information on capacity utilisation, trading activity, or the price and demand for secondary capacity. While larger incumbents appear to have adequate information to trade capacity, potential or new participants, who may seek new or additional capacity, may require better information to participate effectively in the market.

The appropriate calibration of secondary markets, including the strength of any mandated obligations on incumbent shippers, is a complex matter. In particular, the contested issue of whether mandatory capacity release mechanisms, such as 'use it or lose it' obligations, should be imposed cuts across a number of complicated conceptual and empirical issues. SCER officials examined these matters during the development of the Gas Transmission Pipeline Capacity Trading Regulation Impact Statement.

Based on this work, there are opportunities to reduce transaction costs to encourage trade of capacity, which would involve:

- AEMO improving the capability of its National Gas Market Bulletin Board to better present existing data and enhance the usability of the information for market participants

- AEMO incorporating a capacity listing service on the bulletin board

- pipeliners (and shippers via pipeliners) providing additional information on pipeline capacity utilisation and capacity trading activity

- AEMO publishing this new data on the bulletin board

- developing standardised contractual terms and conditions applying to pipeline transport

- developing business tools and processes to expedite and ease the transfer of contractual rights to capacity.

These improvements could potentially reduce transaction costs and assist with making fundamental information available to facilitate market transactions. Greater transparency

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[2] Recognising this factor, parallel with the development of the Wallumbilla gas supply hub, SCER is currently evaluating options for facilitating secondary trading of pipeline capacity.

would also enable policymakers to better understand the market and hence make better informed decisions. This current reform process should be completed as a matter of priority.

APA Group is developing an industry-led 'trade facilitator' model for secondary capacity trading. The proposed model would initially be implemented on two APA pipelines at the Wallumbilla gas supply hub, with the potential for expansion. APA intends that the model will allow any interested market participants, not just existing APA customers, to access secondary capacity. This industry-led initiative to facilitate capacity trading is promising. Although it is only in the early stages of development, in principle industry-led initiatives should be encouraged and supported.

In December 2013, SCER endorsed the Gas Transmission Pipeline Capacity Trading Regulation Impact Statement and agreed to pursue enhancements to information provision and standardisation of contractual terms and conditions. SCER officials will implement this work in consultation with stakeholders in 2014. This work will complement industry-led initiatives and the broader SCER gas market reform agenda and could be made a priority in a revised Australian Gas Market Development Plan.

7.7 Market data and transparency

Some policy options available to governments in the near-term may focus on improving market information on key uncertainties and collecting information to inform ongoing policy development. In addition to those areas of investigation noted above, some of which have transparency components, further specific actions may also be warranted.

7.7.1 Improve information to the markets on CSG delivery risks

Improving information on CSG delivery risks would seem to present the most immediate opportunity for action to alleviate uncertainty in the eastern Australian gas market.

While there are a number of drivers of gas price and availability (most notably LNG prices, costs of production, demand response and supplier behaviour), the largest source of uncertainty in the market currently relates to whether the production of CSG being developed to support LNG trains is on schedule. This information is important to ensuring expectations on both the extent and terms on which suppliers will offer gas to domestic consumers, and the extent to which users will accept that higher prices are a result of market tightness.

The argument that no better information can be provided on these risks is not compelling. Detailed information of this sort is routinely submitted to regulators for offshore exploration and production, and such information requirements are used in other countries. Perhaps the only innovation is that the provision of the information would need to be timely and regular, and it would need to be easily accessible and presented in a way that assists market participants in managing their commercial risks. Where this data contains genuine commercial sensitivities, care would need to be taken to ensure that investors' rights and interests were appropriately protected (by data aggregation, the use of proxies, or both).

While improving market information about gas supply will not resolve market tightness in the near term, it can play an important role in improving the gas market's ongoing operation and performance. The provision of this additional information could also inform planning documents like the *Gas Statement of Opportunities* and assist decision-makers in industry and government. Given the potentially significant costs associated with market reforms, it is vital that policymakers have a clear understanding of the current and expected supply conditions in the gas market so that they can better identify opportunities for market improvement and maximise the net benefits from reforms.

In the short run, there would be limited options to compel the release of this data, however the specific information that could be sought from gas producers via voluntary reporting could include suitably aggregated forms of the following data:

- an assessment of how the current ramp-up to full LNG production is trending compared to forecasts, including required number of wells and production rates to meet LNG contract commitments
- required and expected field production
- current production and well performance data.

Some of this information is already reported to jurisdictions as part of exploration and production lease regulations. Therefore, where possible, reporting could leverage existing reporting requirements so as to minimise compliance costs on industry. The information that is published should provide the market with an overall assessment of current CSG supply and a projected supply profile into the future, and indicate how this aligns with the producers' planning schedules to meet LNG commitments.

A voluntary reporting option could be designed so that upstream and LNG market participants report to Geoscience Australia, and the information could be published to the market through existing AEMO or Geoscience Australia publications. An alternative option could be to pursue the provision of information to a mutually trusted independent party, which would then aggregate and release the information.

While improving the market's ability to form expectations about gas supply is ultimately in the interest of all market participants, there is some self-interest in producers voluntarily providing this information through an appropriate mechanism. However, should voluntary reporting be ineffective in obtaining the required information, governments could consider stronger regulatory options to gather it. Jurisdictions, market institutions and Geoscience Australia all receive regular reporting of some information that is consolidated and published as a combination of primary data and periodic reports. It could therefore also be worth reviewing the scope for compelling additional reporting requirements under existing powers.

From 1 December 2013, Australian-listed companies will be required to report gas resources and production to the ASX. However, a number of companies with interests in eastern Australia are not listed on the ASX and will not be required to report in this manner (e.g. multinationals listed elsewhere). Extending the public collection of data to those companies which do not currently report publically on their petroleum data could address current gaps in the resource and production information base. It is notable that SCER is currently exploring policy options for gas data reporting that is timely, updated and accessible.

7.7.2 Improve planning and transparency mechanisms

While the focus of this study is on the provision of longer term market information to inform efficient investment and supply, it is worth noting that the proposals are consistent with ongoing processes looking at increasing the provision of shorter term information to improve operational efficiencies in the market. A useful option for policy could be to reinforce and accelerate such initiatives.

The National Gas Market Bulletin Board and STTMs aim to improve the efficiency of day-to-day decision-making by increasing the transparency of historical and very short-term information (less than three days) to gas spot market participants, including processing and pipeline capacity data, pipeline flow data and gas spot market prices.

There appears to be ample scope to improve the current arrangements. Pipeliners currently make significant amounts of information publicly available to the bulletin board. Rather than relying on data files that are difficult to access and interpret, there is scope for AEMO to better communicate this information on the bulletin board website. Furthermore, if network availability changes within a 24-hour period, pipeline operators are not obliged to provide updates. Actual flows are provided for the day after, but not in real time or hourly, as occurs in Victoria. Also, given the bilateral nature of the market, details of capacity trades are not available, including sufficiently detailed and timely volumes of capacity (either firm or non-firm or either sought or offered) and bid and ask prices.

Given the importance of this short term information, reforms could put a priority on completing necessary enhancements to the bulletin board. This could be supplemented with better mid-term information. For example, AEMO is developing a medium-term capacity outlook for gas to provide downstream market participants with information on potential processing and pipeline capacity constraints, allowing them to optimise their portfolios.

The commencement in 2009 of AEMO's annual publication of the *Gas Statement of Opportunities* sought to provide forward-looking information on gas reserves, production and demand to aid longer term decision-making. Its continued evolution should be encouraged to provide the best possible reference document for investors.

Beyond the work of AEMO, important initiatives to improve market information are also being developed by industry which should be encouraged. As mentioned earlier, APA Group is developing a proposal to better report and trade unused capacity between its shippers on two of its pipelines that connect to the Wallumbilla gas supply hub. In developing this initiative, it is vital that this information extends to all market participants so as not to compound information asymmetries for smaller participants and new entrants to the market.

The industry is also in the early stages of developing options for a forward price index. Argus Media launched an LNG index in October 2013, including the reporting of a month-ahead Victorian gas price, and the Australian Financial Markets Association is also looking at developing a forward gas price index.

These industry-led initiatives all complement the options outlined in this report. To the extent that they are supported and valued by market participants, they will play an important role in providing information to the market that can inform more efficient market outcomes.

7.8 Is there any role for non-market interventions?

A question raised by a number of stakeholders during the course of this study is whether the eastern gas market requires some form of non-market intervention to smooth the transition to the commencement of LNG exports. This question arises from the current challenging market environment, mainly the reported extreme tightness and associated gas contracting difficulties some large users are experiencing. By implication, there is a concern by some that there is, or will be, a significant disruption in the supply of gas or persistently high prices in the domestic market.

To the extent that market response to these prices might be slow, or might still be associated with large prices rises, some have called for the government to take a more direct role in allocating supply or setting prices.

7.8.1 Examples of reservation and national interest policies

Domestic gas reservation policies are sometimes pursued by governments in response to concerns that domestic consumers will be unduly disadvantaged by the establishment of a gas export market. Interest in reservation policy is driven primarily by an expectation that it will lower prices for domestic consumers (by breaking any link to international gas prices for the reserved gas) or ensuring adequate amounts of gas are available for domestic consumption.

Common examples of domestic reservation policies include:

- *Domestic production obligation policies*, which involve the trade-off of benefits between domestic gas consumers and upstream gas producers. Governments typically seek to secure a guarantee from the producer that a percentage or set volume of gas production from an export-oriented project will be reserved for domestic consumption in exchange for project approvals, land access or other conditions.

- *Acreage reservation policies*, which seek to place conditions upon upstream producers and restrict the sale of any gas produced from a particular tenement to the domestic market only. In this way, certain areas with prospective gas resources are reserved for domestic consumption only.

- *Export controls*, which are designed to restrict or limit the international sale of gas. An export control policy reviews whether a prospective gas export project should be granted an export licence. The assessment process may involve some type of test such as whether LNG exports are in the national interest.

Gas reservation policies have been adopted domestically in Western Australia and Queensland (in place but yet to be applied), and internationally, for example, in the United States of America and Canada. A summary overview of reservation policies in each of these jurisdictions is provided in Appendix A.

Whether the outcome being pursued is ensuring that sufficient gas production is allocated to the domestic market or that gas exports occur only after domestic needs have been fulfilled, the aim of a reservation policy is to prioritise a portion of gas supply to satisfy domestic demand. However, the introduction of a reservation policy would also distort market signals which may increase the risk of under investment and defer the development of new gas supply, or may be ineffective if supply is simply unable to respond.

7.8.2 Trade-offs

In its most pure form, a domestic gas reservation policy implemented in response to a relatively large demand for export gas will reduce the amount of gas that producers have available to sell for export and increase the amount of gas they supply to the domestic market. This additional domestic supply then has the potential to reduce the domestic price relative to the export price from that which would have prevailed in the absence of the policy. Hence, in the short term, domestic gas consumers receive a gain from the lower gas price while the benefits to producers are reduced.

This creates an economy-wide trade-off: the economic cost from introducing a domestic reservation policy is determined by netting-off the resulting gains for domestic consumers against the losses for both producers and government revenue, and efficiency losses as the gas market adjusts to the new conditions. The overall net economic impact is likely to see a reduction in economic welfare if Australia foregoes export earnings (and tax revenues) in favour of (presumably lower value) domestic production, and lower future exploration and gas development activity.

The diversion of gas to the domestic market under a reservation policy could, therefore, have both short- and long-term effects on the price and availability of gas domestically. Where the supply side is already tight, the importance of incentivising the supply response grows, and the chances of such policies causing net losses dramatically increase.

The desired market response to a tightening in supply and the associated higher gas price is an increase in gas exploration, development and production. A reservation policy acts contrary to this goal by creating a perverse signal to the upstream sector, which diminishes incentives for bringing on new supply and potentially creates conditions for tightness in the gas market to persist.

There has been some debate as to whether there is a form of intervention which could minimise the adverse consequences of reservation. These include reserving smaller amounts (which are very low proportions of export contracts) or only applying reservation to future acreage or projects.

The primary difficulty with such variants is they are either ineffective (affect supply only in the long run and well after current shortages) or still present a very negative signal to investors at a time which the reverse is required. In the eastern market they are also complicated by cross jurisdictional effects, where benefits and costs of interventions would cross state borders, but reservation policy would be instituted within a particular jurisdiction. While reservation of future acreage might be the least distortionary, it remains difficult to justify.

An added complexity is while there remains ambiguity on willingness of governments to intervene in markets, this also may affect the investment environment. It is possible associated policy uncertainty may cause market participants to delay making commitments to gas contracts and investments until the uncertainty is resolved.

7.8.3 Should government maintain a reservation option?

Two positions on domestic reservation policy are available to governments: either interventions of this type could be firmly dismissed or reservation policy could be set aside for further consideration.

The explicit dismissal of reservation policies by government would be consistent with avoiding potential market distortions and the consequent adverse outcomes associated with this type of intervention. Reservation policies that lower domestic gas prices risk discouraging both new supply from being brought to market, which may contribute to recurrent or persistent market tightness, and investment in the upstream sector. In the absence of evidence that there is a major market failure, increasing supply in response to market signals remains the preferred approach for dealing with tightness in the gas market.

An Australian Government rejection of domestic reservation as a policy option would not necessarily preclude state and territory governments from adopting acreage reservation policies. The states retain title to onshore petroleum resources and have the authority to apply such a policy. However, acreage reservation should only apply to the release of new acreage to avoid sovereign risk.

The alternative position on domestic reservation policy available to government is to retain the option to consider it further. This position may be consistent with government reserving the right to act through a non-market intervention in the interest of the community if compelling reasons to do so come to light.

A domestic reservation policy is not an obvious, first-preference policy tool to remedy a tightening in eastern market gas supply. It is unlikely to make any difference to the difficulties being experienced by some consumers during the current transition period. It is also likely to have negative implications for supply response and the market in general in future. Building confidence in, and oversight of, the market as described in this report is a more appropriate response to the challenge, particularly in the current environment in which there is a lack of sufficient information for the market and governments.

7.9 Governance and implementation

7.9.1 Improve gas market governance

The current dynamic in Australia's gas market is largely the result of rising costs for developing gas and regulatory decisions made in individual jurisdictions which have had significant cross-jurisdictional impacts. Those implications were not well understood at the time of those decisions and were not the subject of any national debate, analysis or review. While it is entirely possible that review or debate would not have changed outcomes, it raises a question about the effectiveness of the governance arrangements of the national gas market.

The successful functioning of the gas market requires sound policy development and implementation by the responsible institutions. Responsible governance is required to develop and administer the legislative framework within which the market operates and natural monopolies are regulated, to make appointments to statutory bodies that determine market rules and undertake regulation, and to provide policy direction where appropriate.

In a climate of rising gas prices and supply tightness, it is crucial that stakeholders (consumers, industry and government) have confidence that the market institutions exercise their powers efficiently and effectively.

Reflecting the division of powers under the Australian Constitution, energy market reforms are jointly progressed by the Australian Government and the eight state and territory governments under a national framework defined through the intergovernmental Australian Energy Market Agreement, the National Gas Law and the National Gas Rules.

SCER, previously known as the Ministerial Council on Energy (established by COAG in June 2001) provides national oversight and coordination of policy development in Australia's energy sector. SCER has responsibility for:

- oversight of Australian energy markets, including for electricity and gas, particularly in terms of enhancing the efficiency of energy supply. This covers joint energy efficiency measures which act directly on the generation, distribution, transmission, retail or delivery of energy, or require changes to the National Electricity or Gas rules and associated laws and regulations
- energy security and emergency management of national liquid fuels emergencies
- progressing constructive and compatible changes to the basic legislative and policy framework for the sustainable development of resources
- facilitating the economically competitive development of Australia's resources.

SCER, its jurisdictional regulatory bodies, and its three independent market institutions, the AEMC, AER and AEMO have varied roles, responsibilities and powers to regulate and operate at different points of the supply chain.

SCER generally operates under three priorities:

- addressing issues affecting investment in resources exploration and development, including access to land and infrastructure
- assessing existing market mechanisms and regulatory frameworks to ensure the facilitation of adequate, efficient and timely investment in, and operation of, gas production and infrastructure
- identifying changes required to ensure market resilience and energy security
- ongoing testing of national emergency management arrangements for gas.

In the event of natural gas supply shortages, SCER also has a role to play under the National Gas Emergency Response Protocol. Developed in May 2005, the objective of the Protocol is to provide for more efficient and effective management of major natural gas supply shortages to minimise their impact on the economy and the community, and thereby contribute to the long-term community objective of a safe, secure and reliable supply of natural gas.

SCER has developed the Australian Gas Market Development Plan which outlines how existing work is aimed at improving the functioning of the market and removing impediments to supply. SCER is also well placed to provide leadership in the consideration of the options discussed in this document.

Heighten SCER's roles in monitoring and supervising markets

Serving consumer interests in accordance with the National Gas Objective requires that the key institutions are well resourced and equipped for their roles, have the confidence of the community and are subject to appropriate oversight by SCER. As the gas market transitions, it is crucial that the existing governance structures are not only appropriate but also serve as vehicles to facilitate reform.

Previous SCER reforms have taken place in the context of a predictable gas market environment. Leadership in a dynamic environment may require a different approach to governance by SCER and/or its institutions and jurisdictional government agencies.

There is a need to raise gas issues to the forefront of the SCER agenda, particularly during the transition period, and a need for a more dynamic flow of update information through to energy ministers. This could take the form of more regular reports on gas from the energy market institutions, and monitoring and considering the outcomes of potential reviews. For its part, the Australian Government is developing a stronger gas market modelling and analytical capability in BREE, which could help build understanding of ongoing market developments.

SCER could also be better informed of upstream data through updated and more accessible advice from geoscience agencies and state regulators. As discussed earlier, there are current gaps in the gas resource and production information base that make policy decisions and reform sequencing difficult to formulate.

7.9.2 Develop clear accountability timelines and protocols

Consideration could be given to making the gas market roles and responsibilities of the AEMC, AER and AEMO clearer. This could take a number of forms, potentially including clarification of accountabilities and roles, and as necessary reflecting these in protocols, intergovernmental agreements, and national laws. This could potentially be integrated with the recent commitments to undertake reviews of the governance arrangements for the energy market bodies in 2014.

For the AER and AEMC, this could be achieved through integration with existing initiatives to develop clear key performance indicators to form the basis of enhanced annual reporting. For AEMO, a number of the policy options canvassed require additional actions, particularly around improving market data, and there could also be merit in giving further consideration to AEMO taking on a broader gas market operator role.

At present the only specific agreement (Memorandum of Understanding or MoU) on gas under SCER relates to cross-jurisdictional emergency management. The Natural Gas Emergency Response Protocol (mentioned in section 7.9.1), provides for coordinated and efficient management of major natural gas supply shortages in the absence of a legislated national emergency management framework (as exist for liquid fuels under the *Liquid Fuel Emergency Act 1984* (Commonwealth)). The review of this MoU, scheduled for 2014, could be used to further clarify emergency management arrangements and also provide insights on whether this is a useful model for other cross-jurisdictional gas issues.

The timelines and processes for current gas market reform commitments are currently summarised in the Australian Gas Market Development Plan, which has been referenced a number of times in this report (http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/). It would be timely to review and update this plan and introduce public milestone reporting on agreed reforms.

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8. Conclusions and next steps

This report started with a question about the 'golden age of gas'. The historical development of the domestic gas market has served Australia well, and large-scale investments in gas exports will position Australia as a globally significant energy supplier. Despite the inevitable changes in markets that globalisation brings, the difficulties Australia is encountering would be the envy of many countries. The market and investment environment that has served Australia well to date has contributed to a rapid growth in opportunities in LNG project development. The investments are set to create opportunities for Australian citizens and drive a new phase of investment in a gas market that was previously limited in opportunities.

With change also comes challenge, particularly for those who have to adapt quickly to a new market dynamic of massive new demand and supply uncertainty. This does not mean that the market is 'failing', or that there is cause for government intervention. It is somewhat paradoxical that calls for intervention in the gas market are expressed enthusiastically alongside calls to for more transparency and competition in the market. In many ways, this is an environment in which governments should act with caution and where short-term solutions may be undesirable and worsen an already difficult situation.

Geoscientific data has demonstrated that Australia has substantial conventional and unconventional gas reserves and has significant potential gas resources that are yet to be explored. As the global demand for gas increases over coming decades and technology advances, the incentive to explore and exploit currently uneconomic reserves will increase. However, the rapidity and efficiency of a supply response will depend in large part on clear market signals and effective government regulation.

The development of LNG export facilities has introduced a significant new dynamic into the Australian domestic gas market. The previous stable and long-term contract market for domestic gas supply in the eastern market will now be subject to market forces that are determined on the global stage. How the market will respond, and the nature of the transition to a more dynamic market, are not clear – primarily due to the asymmetries of information in an opaque, long-term contract based market and the presence of some new and large risks in the supply-demand balance. This is largely uncharted territory – no country has tried to deliver this many LNG trains from CSG resources in such a short period – so it is not surprising that high levels of uncertainty prevail.

The opening of the eastern market to global competitive forces is affecting domestic consumers and producers alike. In the lead-up to LNG exports, the cost of producing gas to satisfy demand is increasing and there is uncertainty about the timing and quantum of supply to the domestic market, which will flow through to the prices being faced by domestic gas consumers. The linking to the international market may also support further investment in gas production, given the larger market that suppliers can potentially access.

Quite rational interpretations of supply expectations, cost drivers, competitive behaviour and the ability of demand to respond to price rises lead to divergent expectations on price. This may have significantly disrupted contracting activity, and created opportunities for suppliers, who have the lead hand in a tight market environment, to delay striking deals until conditions are most favourable. For users, the key information asymmetry in the market – if CSG production will be sufficient to meet LNG export contracts and schedules – will be resolved over time, but the later it is resolved, the more likely it is that the transition and adjustment process will be more prolonged and difficult than it might otherwise be.

Under all the scenarios modelled for this report, future gas prices remain high relative to historical levels due to higher production costs and linking to the LNG netback price. It is therefore unsustainable for government to support major users whose economic viability depends on low prices. All users will need to accept that gas prices will be set in a more dynamic price environment. Ultimately, the economic competitiveness of individual users will determine the outcomes. While price discovery has been difficult for some time, the link to international markets has been coming for a number of years.

There is reason to believe that supply will respond to the step-change in price being experienced, and there are already some early signs of that response. Facilitating and encouraging a supply response is fundamental to dealing with a potential gas shortage. Policy actions must therefore be constrained to those that do not cut across property rights, and must engender a certain and predictable regulatory and investment environment. The focus of government policy should be to ensure that the operation and regulation of the market facilitates a smooth transition and provides the best opportunity for all market participants to adjust. In this way, the economy will reap the maximum benefits from the LNG developments.

Producers who consider their long-term position in Australian markets have an incentive to balance the needs of domestic consumers against the development of new export markets as the demand for gas diversifies. The government should pursue a certain and predictable investment environment that includes well-informed approaches to matters such as competition policy. The government could also increase its capabilities to monitor and, where relevant, enforce established areas of regulation.

Just as the market operates without borders, these approaches should be consistent across jurisdictional boundaries and levels of government. So it is important that improvements in accountability and the governance of the domestic gas market are implemented on a cross-jurisdictional basis. It is also important that all jurisdictions do not unnecessarily restrict supply development, particularly during this period of tightness. The interconnectedness of the market should not be used as an excuse for complacency on regulatory frameworks, or as a reason to avoid taking responsibility for market outcomes. All governments should focus on removing impediments to supply and maximising the opportunities from their acreage.

Implicit in the terms of reference for this study was the intention that it would provide greater clarity about price expectations in the future. While much has been learned about the nature of prices currently under negotiation, and some of the underlying drivers of prices, particularly through modelling, no single reference price series could be established.

This is not surprising, given the nature of the gas market and the range of possible scenarios confronting it, and it would perhaps be inappropriate in a time of divergent price expectations for the government to seek to give an 'authoritative' view of price.

An important policy issue associated with the price narrative is the extent and duration of any tightness in the market. It is possible that in a period of tightness price will overshoot export parity until there is sufficient supply or information to either overcome transient market power or readjust risk expectations.

Information on supply and demand conditions is the key to informing policy to address such risks as it builds confidence in the efficiency of the market and improves the information set that underpins the price discovery process and supply and demand response. This study puts forward a number of options for improving the information set and informing the regulatory agenda.

More fundamentally, the discussion of these issues raises broader questions about whether the Australian market has now reached a point in its development where further reform is appropriate. There seems to be widespread support for using current experience in the market to think more carefully about that forward agenda.

Reform for reform's sake is inconsistent with building a certain regulatory environment for investment and improving market signals. While there is a healthy debate about lessons from past Australian and international experience on the ability of governments to facilitate market change, engagement with stakeholders on principles to guide the evolution of commodity, transportation and financial markets is crucial. Specific actions, including AEMO completing the Wallumbilla gas supply hub, progressing pipeline capacity trading, and further analysis by market institutions would help to clarify the roadmap for those reforms. Specific research on mechanisms to improve the depth and liquidity of facilitated markets and potential risk management tools, such as financial derivative markets, could also usefully inform the forward agenda.

This report suggests that the forward agenda be developed as a priority in consultation with stakeholders and that clear and accountable milestones be developed and progressed through SCER.

This report considers a picture of the market at a particular point in time, but reflects an evolving understanding of the complexities of the gas market by the Department of Industry and BREE. Given the dynamic nature of the market, the department and BREE will continue ongoing analysis in this area to inform the debate. Stakeholder feedback on any matters raised in this report is welcomed.

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Appendix A: Reservation policies and export controls

1. Commonwealth

While few jurisdictions have either implemented or considered implementing a domestic gas reservation policy, the Australian Government has not enacted a national reservation policy. In the *Energy White Paper 2012* (DRET 2012:144), the government stated its policy on domestic gas reservation:

> [T]he Australian Government does not support calls for a national gas reservation policy or other forms of subsidy to effectively maintain separation between domestic and international gas markets or to quarantine gas for domestic supply.

No reservation policies are applied to gas exploration and production in Commonwealth offshore waters (where the Australian Government has jurisdiction), and there are no national export controls for LNG.

2. Western Australia

Western Australia is the only Australian jurisdiction that has enacted a domestic gas reservation policy. The policy is not formalised in legislation, but instead entails a commitment to negotiate on a case-by-case basis for the equivalent of 15 per cent of production from LNG export projects to be reserved for domestic consumption (DPC 2006). Industry cooperation with the policy is a trade-off for access to state-owned land for the siting of LNG processing facilities. Floating LNG processing projects are therefore exempt from the requirement to reserve 15 per cent of their production for domestic consumption.

The reservation of gas for domestic consumption from LNG export projects dates back to 1989 at the commencement of the North West Shelf project. State agreements that facilitated the establishment of the North West Shelf and Gorgon LNG export projects incorporated a commitment to supply a proportion of gas to the domestic market.

Since the statement of the current reservation policy by the Western Australian Government in 2006, the Woodside Pluto LNG project is the first and only LNG export project to submit to the policy. After an initial start-up period, Woodside has agreed to supply the equivalent of 15 per cent of LNG production from the project for domestic consumption.

The 15 per cent target reflects 2006 estimates of future Western Australian domestic gas needs, estimated gas reserves and forecast LNG production. As those estimates are subject to change over time, the target will be subject to periodic review. The Western Australian Government has committed to review the domestic gas reservation policy in 2014–15.

3. Queensland

Queensland does not have a gas reservation policy in place but has the legislative ability to apply its Prospective Gas Production Land Reserve (PGPLR) policy as a condition for the release of petroleum-producing land. The PGPLR policy provides the ability to grant tenure such that any gas produced for sale from the area can only be consumed within the Australian gas market. The Queensland Government can choose to enact the policy if supported by outcomes of Queensland's annual Gas Market Review process or if domestic gas market supply becomes constrained or is forecast to become constrained.

The rationale for the establishment of the PGPLR policy was to ensure that the growth of the LNG export industry did not create a shortage of supply for large users in the domestic market (Gas Security Amendment Bill 2011 (Qld), Explanatory notes).

The policy was enacted through amendments to Queensland's *Petroleum and Gas (Production and Safety) Act 2004* through the *Gas Security Amendment Act 2011.*

In its 2009 *Domestic gas market security of supply* consultation paper, the Queensland Government proposed two options that could provide additional certainty about the price and availability of gas supply to the domestic market (DEEDI 2009):

▪ a reservation policy based on a percentage of total gas production (similar to the Western Australian model)

▪ the option to reserve gas acreage and release that land with conditions that make gas production exclusively available to the domestic market.

The consultation paper noted that the PGPLR policy was a 'light-handed' and more adaptive approach compared to the percentage of production reservation model.

The 2012 Gas Market Review delivered by the Queensland Gas Market Adviser recommended that implementation of the PGPLR policy could not be supported (DEWS 2012:38). That recommendation was made on the basis that LNG projects under construction had already taken final investment decisions. However, the extent of domestic gas market liquidity and the potential enactment of the PGPLR policy would likely be considered if further LNG train options were advanced.

4. New South Wales

A New South Wales parliamentary inquiry into CSG in May 2012 recommended that the New South Wales Government implement a domestic gas reservation policy, whereby a proportion of the CSG produced in New South Wales would be reserved for domestic use (NSW Government 2012). The recommendation was contingent on the expansion of the state's CSG industry.

The basis for the recommendation was that reserving local CSG production could help to ease pressure on price increases and enhance energy security. The parliamentary committee referred to the Western Australian domestic gas reservation policy in recommending that policy.

The New South Wales Government's response to that recommendation in October 2012 was that a domestic gas reservation policy was unnecessary. This was on the basis that prospective New South Wales CSG resources were not contracted to LNG export facilities and that, if those reserves were to be exploited, they were likely to be used for domestic purposes anyway. The government also noted that implementing a reservation policy during the early development stages of the local CSG industry would create a strong disincentive to investment and cause development costs to rise.

5. International

A range of different approaches have been adopted by governments in other countries either to reserve gas for domestic consumption or to affect gas market outcomes. Several of those approaches are inconsistent with Australian Government policy and are unlikely to ever be adopted in Australian gas markets. Therefore, reservation options such as the nationalisation of gas resources, the establishment of monopolistic government petroleum companies and the exclusion of international oil and gas companies from access to Australian markets are not discussed further. Table A1.1 lists a selected range of countries and the gas market policies they have in place.

Table A.1: Gas market policies in selected gas-exporting countries

Country	Annual gas exports	Gas market policies
Algeria	12.6 Mt (LNG)	• Government-owned company Sonatrach dominates production • International oil and gas companies must partner with Sonatrach (which requires a minimum of 51 per cent ownership in production sharing) • Domestic prices are regulated
Egypt	8.6 Mt (LNG)	• One-third of gas production must be directed to domestic consumers • International producers are required to enter into 50/50 joint ventures with state-owned companies • International oil and gas producers receive capped prices and domestic prices are government subsidised • Restriction on new gas export contracts
Qatar	3.6 tcf (LNG and pipeline)	• Government-owned company Qatar Petroleum dominates production and controls most projects, with international participation • Downstream industrial gas consumption controlled by Qatar Petroleum • Domestic allocation of gas to vertically integrated downstream uses comes with high opportunity cost compared to LNG export value
Indonesia	1.4 tcf (LNG and pipeline)	• Domestic market obligation policy is applied on case-by-case basis to new LNG projects. Domestic gas reservations of up to 40 per cent of production have been agreed for new projects • Domestic gas prices are regulated by government below competitive market rates

Country	Annual gas exports	Gas market policies
Malaysia	1.2 tcf (LNG)	• Government-owned company Petronas monopolises upstream development • Domestic gas prices subsidised by government
Canada	2.2 tcf (pipeline)	• Gas exports require government licence approval • No other policies to preference domestic consumers • Domestic gas prices determined by the market
United States	0.5 tcf (pipeline) 13.1 tcf (LNG conditionally approved)	• Gas exports to non-free-trade-agreement countries require government export approval • No other policies to preference domestic consumers
Norway	3.5 tcf (LNG and pipeline)	• Government-owned company Statoil the dominant producer, with participation from international oil and gas companies • No specific policies to preference domestic consumers • Domestic prices determined by export market
Russia	6.4 tcf (LNG and pipeline)	• State-owned company Gazprom the dominant producer • Significant domestic gas price regulation and subsidisation

The gas market policies of the United States and Canada are examined in further detail below. Their policies have been selected for closer analysis because they are relative newcomers to the international LNG export market and because of their potential to become major global LNG exporters – a scenario analogous to that of the eastern market in Australia.

5.1 United States

In the United States the export and import of LNG is regulated by the Natural Gas Act of 1938. LNG export applications are made to the federal Department of Energy (DOE), which must consider if an application is in the public interest.

The Act deems applications for LNG trade with countries that have free trade agreements with the United States to be in the public interest. Applications for LNG export to non-free-trade-agreement nations require the DOE to conduct a public interest review, which can deny an application only if it can be demonstrated that such an approval would be inconsistent with the public interest.

While the Act establishes the concept of 'public interest', it is silent on the definition of public interest or the criteria the DOE must consider when assessing an application. In considering previous export authorisations, the DOE has used the following criteria (US DOE 2013a:8), published in 1984 as part of policy guidelines originally intended for the assessment of LNG import applications:

▪ the extent of the domestic need for the natural gas proposed to be exported

▪ whether the proposed exports pose a threat to the security of domestic natural gas supplies

▪ whether the arrangement is consistent with the DOE's policy of promoting market competition

- any other factors bearing on the public interest.

At 6 December 2013 export authorisations to non-free-trade-agreement countries had been granted to five LNG export projects and a further 23 non-free-trade-agreement LNG export applications were under review (US DOE 2013b).

5.2 Canada

The Canadian Government has an established regime for the licensing and approval of LNG exports. The National Energy Board, an independent federal agency, is responsible for reviewing and deciding on applications for LNG export licences. The board was established in 1959 to regulate the interstate and international aspects of the oil, gas and electricity industries in the Canadian public interest.

Section 118 of the National Energy Board Act (1985) establishes the criteria upon which prospective Canadian LNG export projects are assessed. It states (Canadian Government 2013a):

> **118.** On an application for a licence to export oil or gas, the Board shall satisfy itself that the quantity of oil or gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada.

The National Energy Board is unable to consider matters that fall outside of this legislated definition, such as environmental impacts. The Act's regulations provide guidance on information to be submitted in support of an application for LNG export approval. This includes (Canadian Government 2013b):

- the source and volume of gas proposed to be exported
- a description of gas supplies, including Canadian gas supply, expected to be available to the Canadian market (including underlying assumptions) over the requested licence term
- a description of gas requirements (demand) for Canada (including underlying assumptions) over the requested licence term
- the implications of the proposed export volume for the ability of Canadians to meet their gas requirements.

As of October 2013, three LNG export licences had been approved by the National Energy Board and another five applications were under consideration.

Further regulation of the Canadian LNG export industry is expected in the near future. Specifically, the province of British Columbia has proposed an LNG export tax linked to market prices (Interfax 2013). The proposed tax is expected to be introduced by provincial legislation following industry consultation.

Appendix B: Facilitated wholesale gas markets

1. Victorian Declared Wholesale Gas Market

The Victorian Declared Wholesale Gas Market (DWGM) commenced in 1999 to manage and balance flows across the Victorian Transmission System (VTS). It is operated by AEMO.

A day ahead of the trading day, participants nominate their bids to withdraw gas from and offers to inject gas into the VTS for the beginning of the gas day (6 am). Following initial bidding, bids may be revised for the intervals of 10 am, 2 pm, 6 pm and 10 pm. On the gas day AEMO schedules the lowest price supply offers to meet demand across the DWGM, creating a clearing price for each interval.

The DWGM is a net market, which means participants only pay the market price for their net withdrawals and receive the market price for their net injections. The market price is a commodity-only price and does not include the costs of transportation. The market has a floor of $0/GJ and a ceiling of $800/GJ. Typically, 10 to 20 per cent of the market's volume is traded at the market price.

The DWGM does not require participants to have gas transportation or gas supply agreements (though most participants do have underlying gas supply agreements), enabling smaller retailers to enter the market relatively easily. As the VTS uses market carriage, DWGM participants do not have the firm pipeline capacity rights of contract carriage transmission pipelines in other states. Participants can acquire an authorised maximum daily interval quantity (AMIQ) to gain priority in times of congestion by entering into a contract with the VTS operator (APA Group).

2. Short-term trading markets

The STTMs provide wholesale gas spot markets for participants to manage contractual imbalances, and facilitate secondary trading and demand-side response from users. The STTMs are operated by AEMO at hubs connecting transmission pipelines and distribution networks, and commenced at the Sydney and Adelaide hubs in 2010 and the Brisbane hub in 2011.

A day ahead, STTM participants place their offers to deliver gas to the hub and bids to purchase gas from the hub, with many participants doing both. Bids and offers are matched and cleared at a single market price for the day, and the shippers that offered their gas below the market price are scheduled by AEMO.

The market price applies to all gas that passes through the hub and includes gas transportation charges to the hub. The market has a floor of $0/GJ and a ceiling of $400/GJ. Most participants would also have an underlying gas supply agreement which continue independently of the STTM.

AEMO provides a market operator service (MOS) to balance flows to and from a hub. AEMO purchases gas from shippers it has contracted for this service and recoups the cost through deviation payments and charges on parties responsible for the imbalance, providing an incentive for participants to have accurate nominations.

At times when a pipeline connected to the hub is constrained, a bid from a shipper without firm pipeline capacity (an as available shipper) can displace a bid from a shipper with firm capacity (a firm shipper). Pipeline capacity contractual arrangements are maintained through a capacity payment from the as available shipper to the firm shipper and, where the same price is bid, prioritising the firm shipper.

3. Gas supply hub

To further improve liquidity and facilitate trading between upstream gas producers and shippers, SCER is introducing a 'brokerage' model gas supply hub trading exchange at Wallumbilla, Queensland, to commence in March 2014. This site was proposed due to the substantial growth in CSG development in the region and its intersection with three major pipelines. If successful, this hub design could be rolled out in other upstream hubs, such as Moomba.

Under the brokerage model, the role of the exchange is to match and clear trades using the existing physical infrastructure at Wallumbilla. Given physical limitations within the hub, three trading nodes will be created, to separately trade gas available to flow down each of the major pipelines connected to the hub.

Unlike the STTMs and DWGM, the gas supply hub is a voluntary market. Those who own gas flowing through the hub under existing contracts can choose whether to participate in the market, and can buy or sell excess gas to better meet their immediate supply and demand needs.

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