

Gas Market Modelling for the Queensland 2011 Gas Market Review



- Final Report
- 29 July 2011



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Executive Summary

Introduction

The Office of the Queensland Gas Commissioner (OQGC) has engaged SKM MMA to undertake gas market modelling for the 2011 Gas Market Review (GMR). The GMR is an initiative of the Queensland Government that informs Government decision making in relation to the need for development of a Prospective Gas Production Land Reserve (PGPLR), more effective resource management, and the development of a more competitive Queensland gas market.

The GMR forms part of a coordinated Whole-of-Government approach to providing regular advice to Government on constraints on gas supply availability, gas market development and security of supply. This study involves analysis of gas market demand, supply and price variations for prescribed scenarios and additional sensitivity analysis on certain variables. The study is presented in the context of the interlinked Eastern Australian gas market, with a strong focus on outcomes in Queensland.

Background

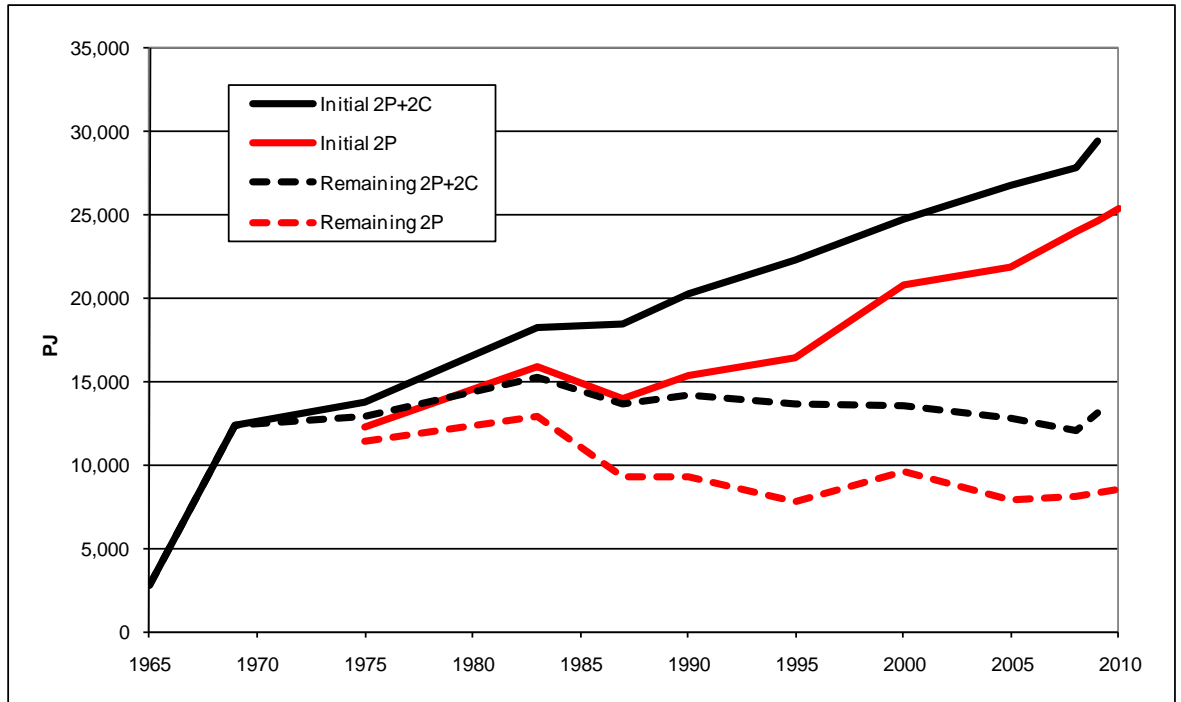
The Eastern Australian gas market has grown steadily since the late 1960s, supported by conventional gas reserves that have remained relatively static since approximately 1980 (refer to Figure E- 1). The past decade however has witnessed rapid growth of coal seam gas reserves (CSG), mainly in Queensland, to the extent that by 2008 it was clear that they could rapidly exceed domestic demand provided that a market could be found, otherwise the development may have stalled (Figure E- 2).

Worldwide, the preferred route to exploiting excess¹ gas is LNG, a global market that saw rapid growth and high prices during the oil price surge from 2003 to 2008. Since 2007 ten proposals have been put forward to export LNG from liquefaction plants to be built on the Queensland coast (eight), in New South Wales and South Australia (one each). Two of the large projects at Curtis Island, near Gladstone, have now passed the final investment decision and their four LNG trains, each capable of delivering about 4 million tonnes of LNG per year, are under construction, with first deliveries scheduled in the period 2014 to 2016. A further project, comprising one or two trains, is expected to reach FID this year.

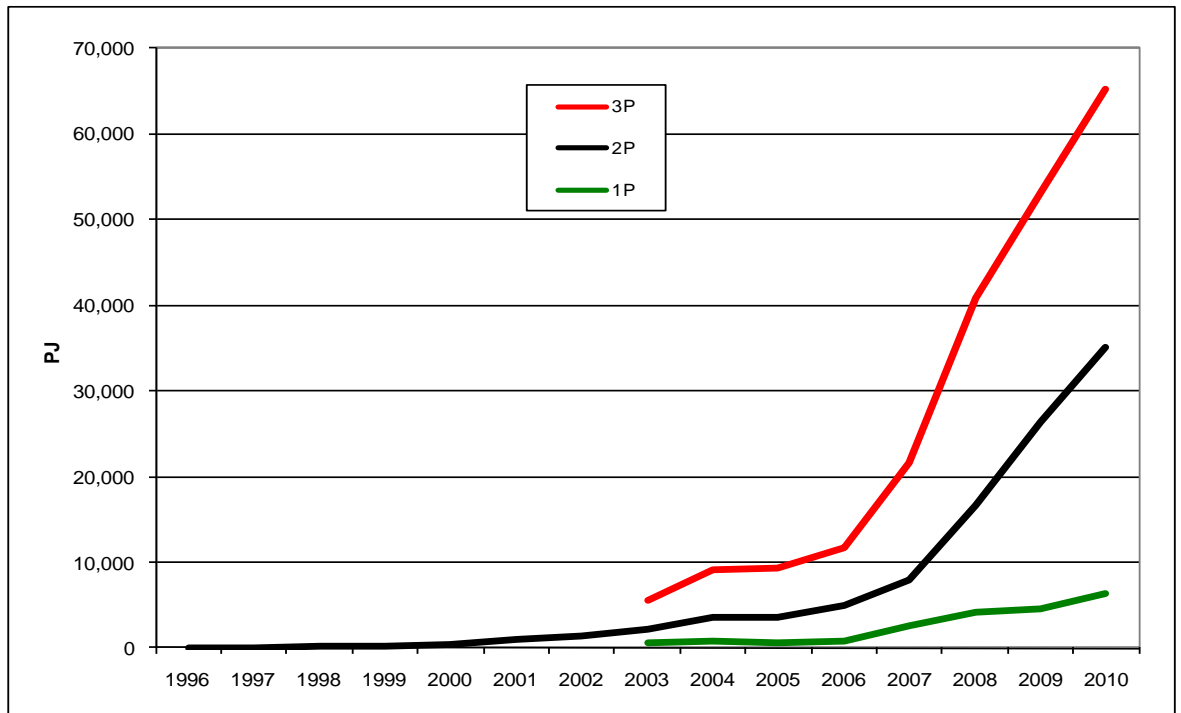
¹ Gas that cannot reach a market by pipeline. LNG is preferred to conversion technologies such as Gas-To-Liquids



■ **Figure E- 1** Aggregate conventional gas resources and reserves, Eastern Australia (PJ)



■ **Figure E- 2** Aggregate CSG reserves, Eastern Australia (PJ)





While there is every reason to believe that the CSG reserves to support some if not all of the LNG projects will eventually be proved up, none of the proponents currently has sufficient proved reserves for the likely duration of their project, for all the trains planned. A strong focus on building reserves for LNG projects has, in the short-term, led to a relative lack of reserves available to support new domestic gas contracts and domestic gas buyers have had difficulty securing such contracts.

The Queensland Government has considered and rejected the concept of reserving a percentage of gas produced as a means of ensuring availability of gas for new domestic contracts. Instead the Government has adopted the approach that it will, if necessary, set aside prospective acreage to be dedicated to the domestic market.

Findings

To assess the future balance of gas demand and supply across Eastern Australia SKM MMA has:

- 1) Developed three energy-economic scenarios (low, medium, high), comparable to the scenarios used by AEMO in the 2010 GSOO, and for each scenario prepared:
 - a) projections of future gas demand for the domestic sector, comprised of two sub-sectors:
 - i) utility (residential and small medium business) and large industrial customers
 - ii) gas for power generation including large cogeneration projects
 - b) projections of the level of LNG exports from Eastern Australia, linked to global demand and supply conditions
 - c) estimates of the timing of gas reserve commitments to long-term contracts to meet the above demand, taking into account existing reserves commitments to domestic contracts.
- 2) Reviewed gas reserves and determined potential reserves development profiles based on recent growth rates, currently known contingent and prospective resources and potential impediments to reserves appraisal such as recent flood events in Queensland.
- 3) Tested the ability of reserves growth to physically meet the timing requirements of new domestic and export contracts, taking into account the multi-train targets of LNG projects.
- 4) Reviewed other aspects of gas supply including likely future production and transmission costs
- 5) Modelled the economic balance of demand-supply and consequent price outcomes in the three scenarios
- 6) Examined the capacity expansion requirements for pipelines (in Queensland only)

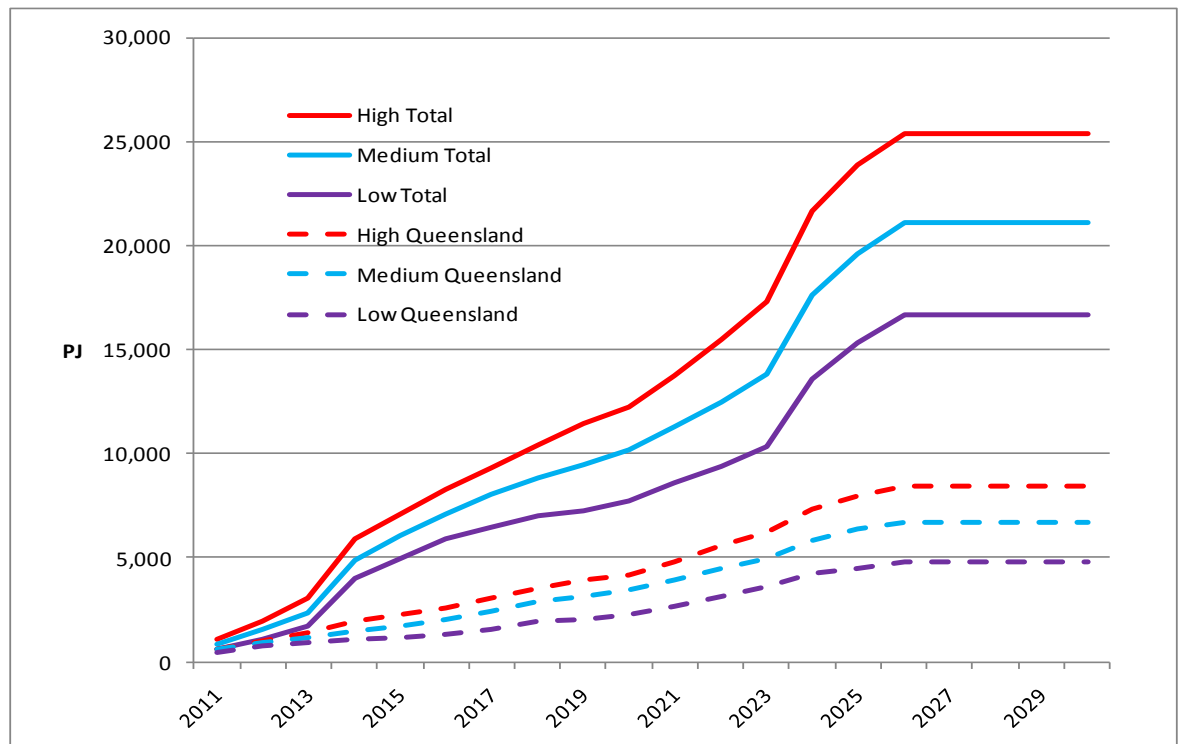


Physical demand-supply balance

Figure E- 3 and Figure E- 4 below illustrate the projected domestic and export reserves requirements respectively and demonstrate the potential for export requirements to considerably exceed those of the domestic market in the Medium and High scenarios. For both markets it is assumed that contracts are entered four years before first delivery, allowing for development of new production facilities and transmission capacity prior to first supply. The projections are flat after 2026 because the underlying demand projections extend only to 2030.

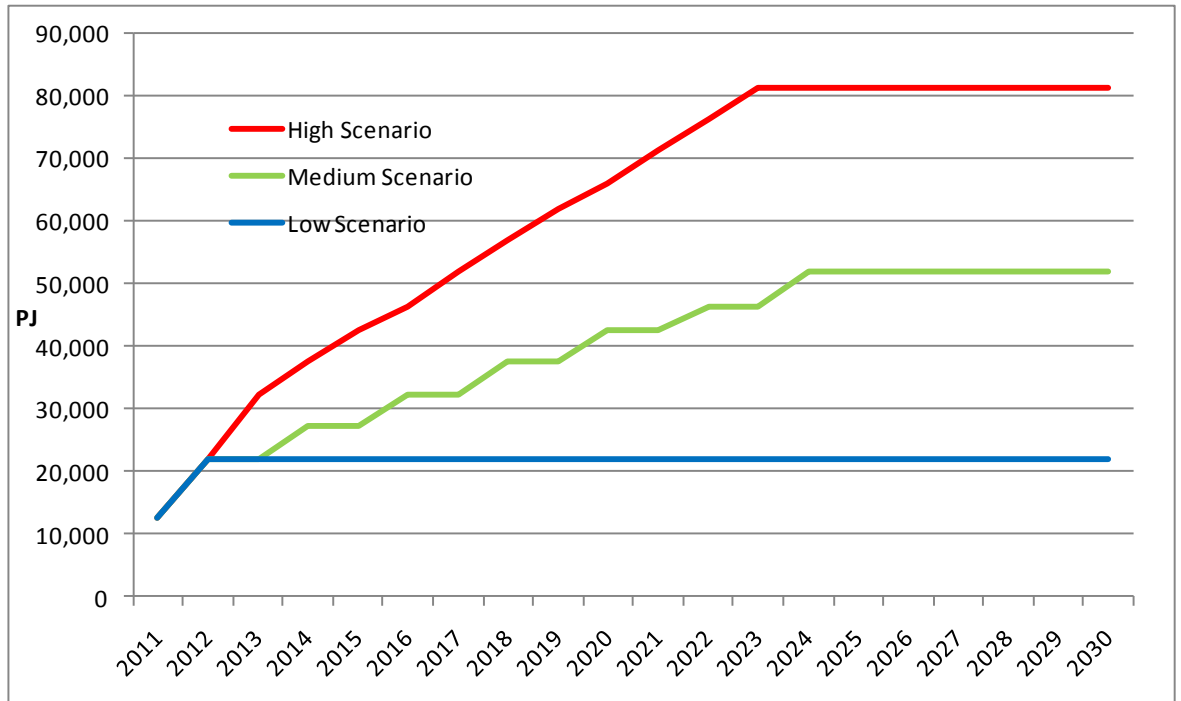
Aggregate domestic and LNG reserves requirements are compared with two reserves projections in Figure E- 5. The reserves projections represent growth at the maximum level that appears possible given current contingent and prospective resources (the 2C + P case) and a case in which reserves appraisal is reduced to 50% in 2011 and 2012 on account of flood events in Queensland. The projections suggest that there are buffers of at least 20,000 PJ of uncontracted reserves up to 2022 in all scenarios and that there will not be any gas reserve adequacy issues in the short to medium term.

■ **Figure E- 3 Cumulative domestic gas reserves requirements (PJ)**

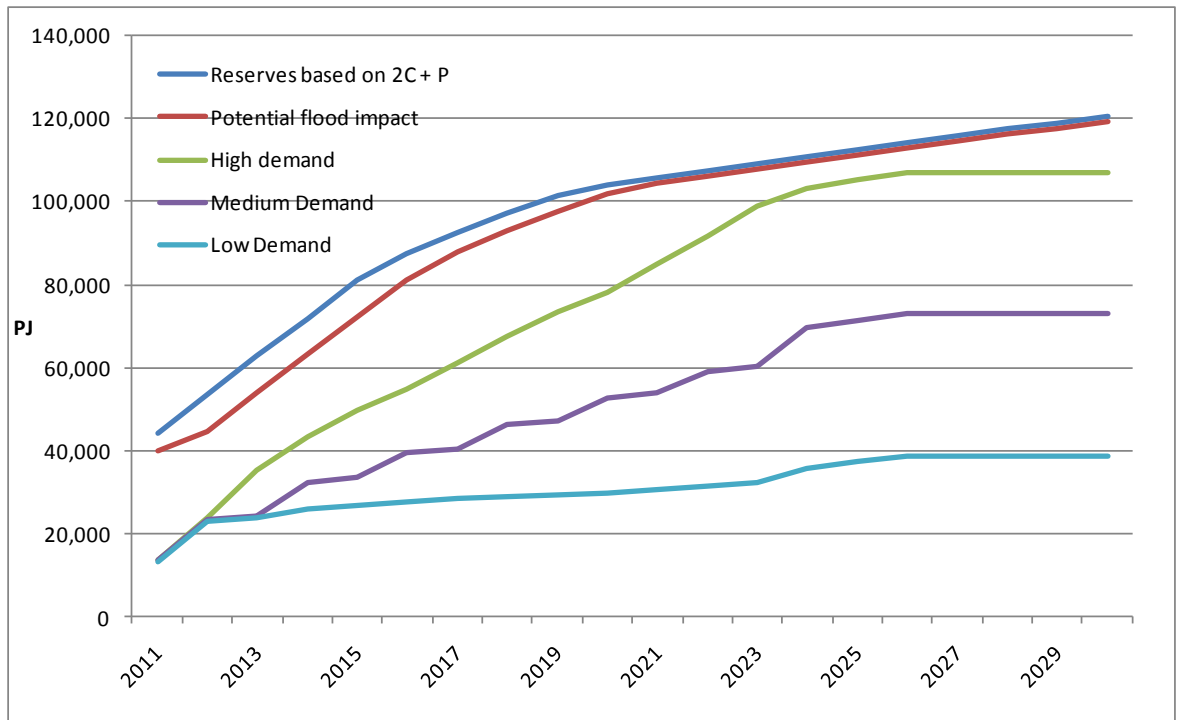




■ **Figure E- 4 Cumulative LNG export gas reserves requirements (PJ)**



■ **Figure E- 5 Combined domestic + LNG reserve requirements vs 2P uncontracted gross reserve projections (PJ)**

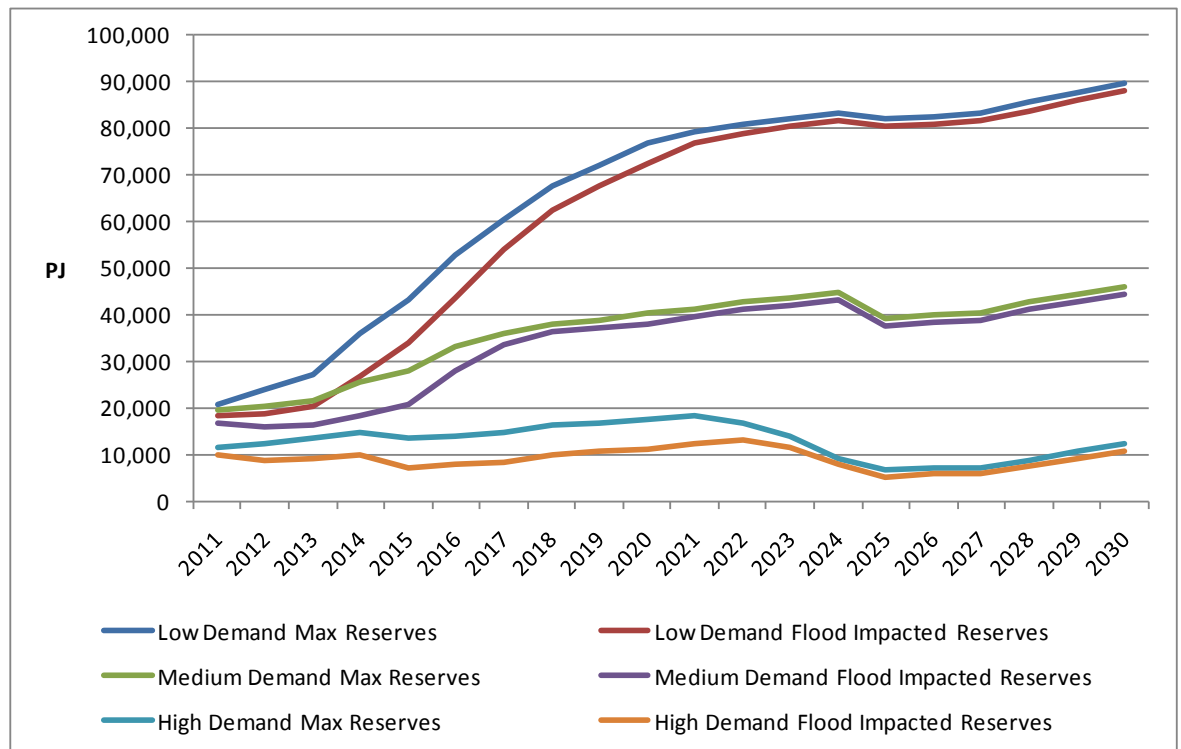




The adequacy of margins between 2P reserves and the demand for reserves to meet new contracts, even though it takes into account contracting four years ahead of first gas delivery, does not however imply that the amounts of reserves will be made available to the domestic market. Reserves likely to be made available to the domestic market are reduced by LNG proponents need to build up reserves for multi-train projects and by uncertainties in the relationship between reserves and rates of gas production.

Gas reserves available for new domestic and third party LNG contracts (uncontracted and not pre-committed to future LNG) have been estimated taking these factors into account (Figure E- 6). In the High Demand scenario with maximum reserves development the reserves available grow steadily from approximately 11,000 PJ in 2011 to 17,000 PJ in 2020 but in the High Demand scenario with flood impacted reserves the reserves available remain at approximately 10,000 PJ from 2011 to 2017. Reserves available in the Medium and Low scenarios are considerably higher.

■ **Figure E- 6 Gas reserves available for new domestic and third party LNG contracts, Eastern Australia (PJ)**





It is noted that approximately 8,200 PJ of the 10,000 PJ of reserves available to the domestic market in the High Demand – Flood Impacted Reserves scenario are in Victoria, in as yet undeveloped basins in NSW and in the Bowen Basin at Moranbah which is not currently connected to markets other than Townsville and seems unlikely to be connected until required by the Arrow LNG Project in 2017. If these reserves, which are difficult for Queensland buyers to access, are excluded, then the reserves demand-supply balance in 2011 and 2012 is in deficit (Table E- 1).

This scenario shows that a physical shortfall of gas, i.e. inability to source gas for contracts, is possible under circumstances that are plausible. The domestic shortfall can be avoided only by deferral of third party LNG contracts or satisfaction of the LNG contracts by reserves that have been excluded, such as Gunnedah or Clarence Morton Basin reserves. It is noted that physical shortfalls do not occur in any of the other scenarios depicted in Figure E- 6.

■ **Table E- 1 Queensland Reserves Demand-Supply Balance 2011 and 2012, High Demand, Flood Affected Reserves (PJ)**

	2011	2012
Demand (Domestic and 3rd Party LNG)	1,761	612
Supply (Cooper, Surat and Southern Bowen basins)	1,751	197
Net Position	-10	-415

Economic demand-supply balance and price projections

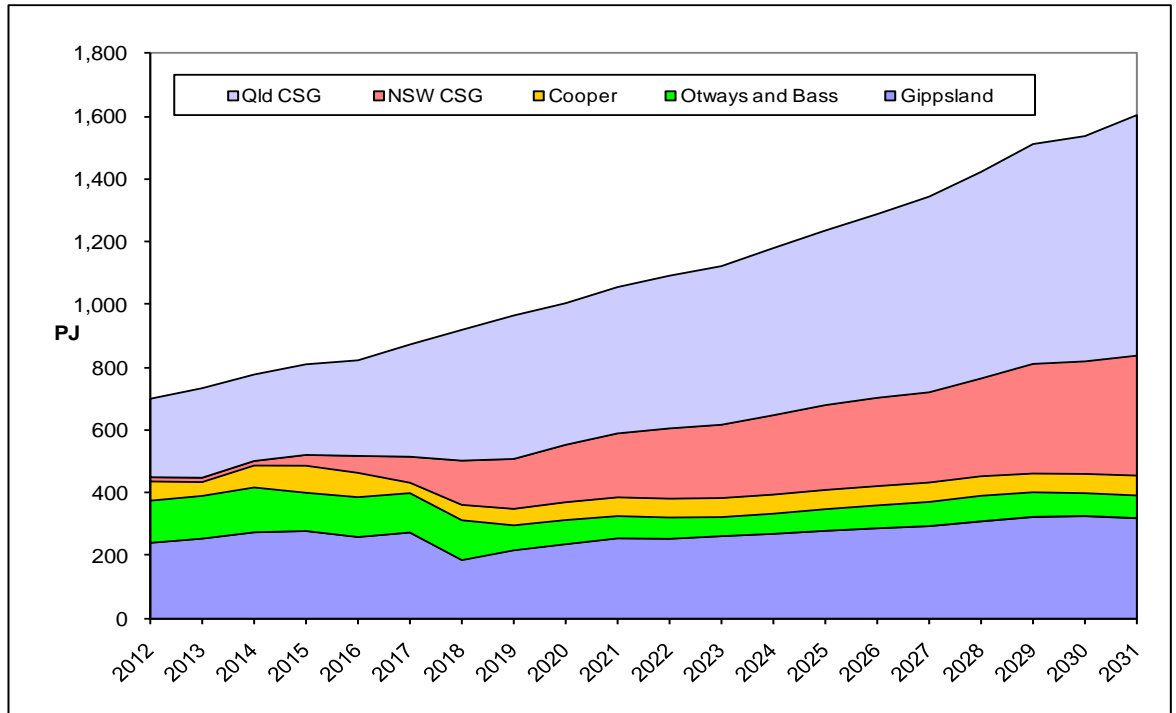
The economic gas demand-supply balance has been determined in each scenario using SKM MMA's proprietary model, MMAGas, Market Model Australia – Gas, which replicates the essential features of Australian wholesale gas markets:

- A limited number of gas producers
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Domestic market growth driven by gas-fired generation and large industrial projects.

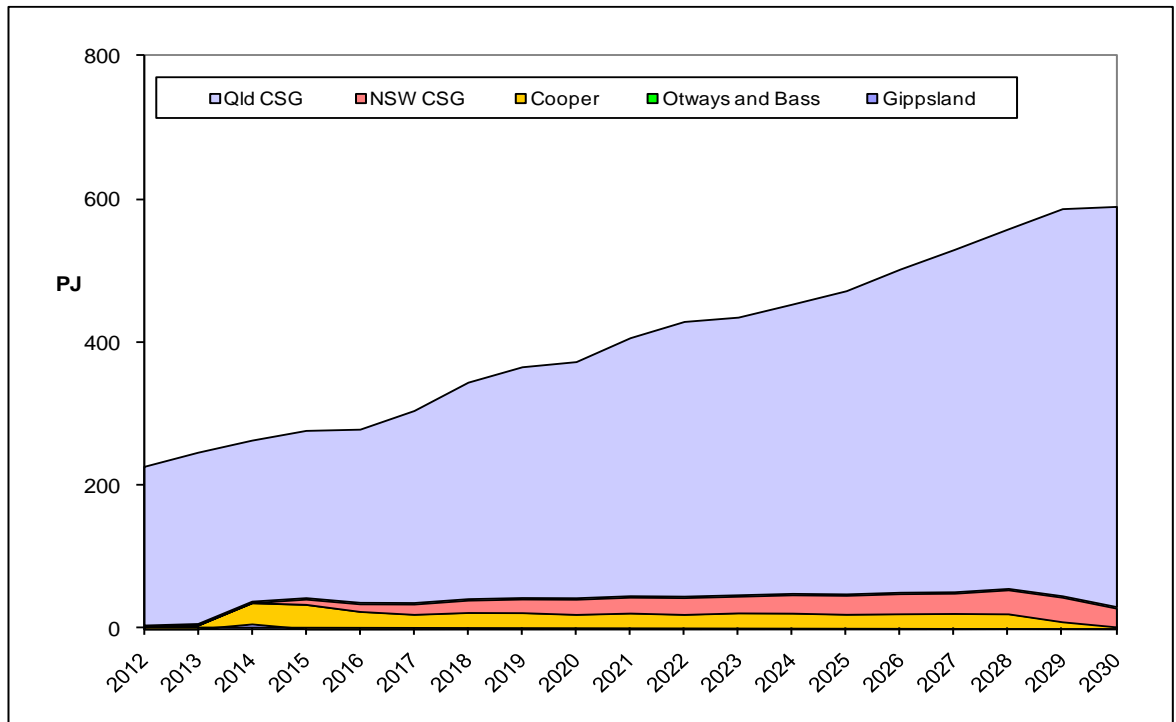
Eastern Australian gas supply is projected to come increasingly from CSG, not only from Queensland but also New South Wales (Figure E- 7 and Figure E- 8).



■ **Figure E-7** Projected gas supply, Eastern Australia domestic only, Medium Scenario



■ **Figure E-8** Projected gas supply, Queensland domestic only, Medium Scenario



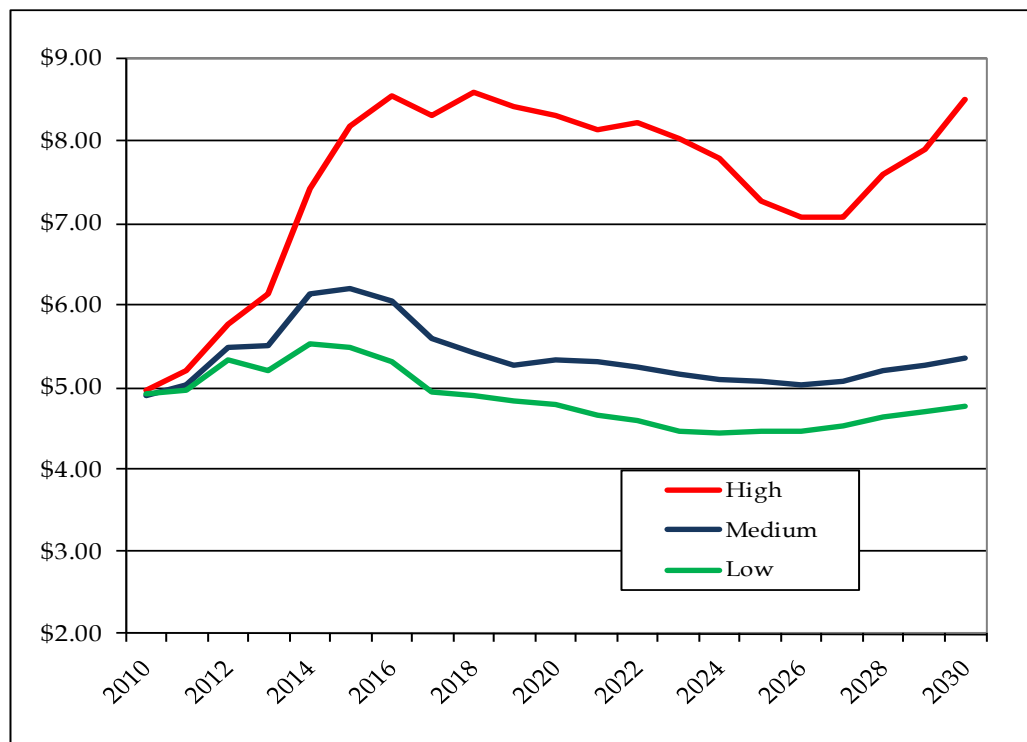


The domestic supply patterns vary considerably between scenarios, with less Queensland CSG in the High scenario, where it is more dedicated to export, and more NSW CSG and Cooper Basin gas.

Projected new contract delivered gas prices in Queensland also vary considerably between scenarios (Figure E- 9). New contract prices are projected to remain relatively flat in the Low scenario, to rise by over \$1/GJ and then fall back in the Medium scenario and to rise by more than \$3/GJ in the High scenario and then decline slightly. Similar patterns apply in all Queensland zones and average contract prices follow new contract prices with a considerable time-lag (Figure E- 10).

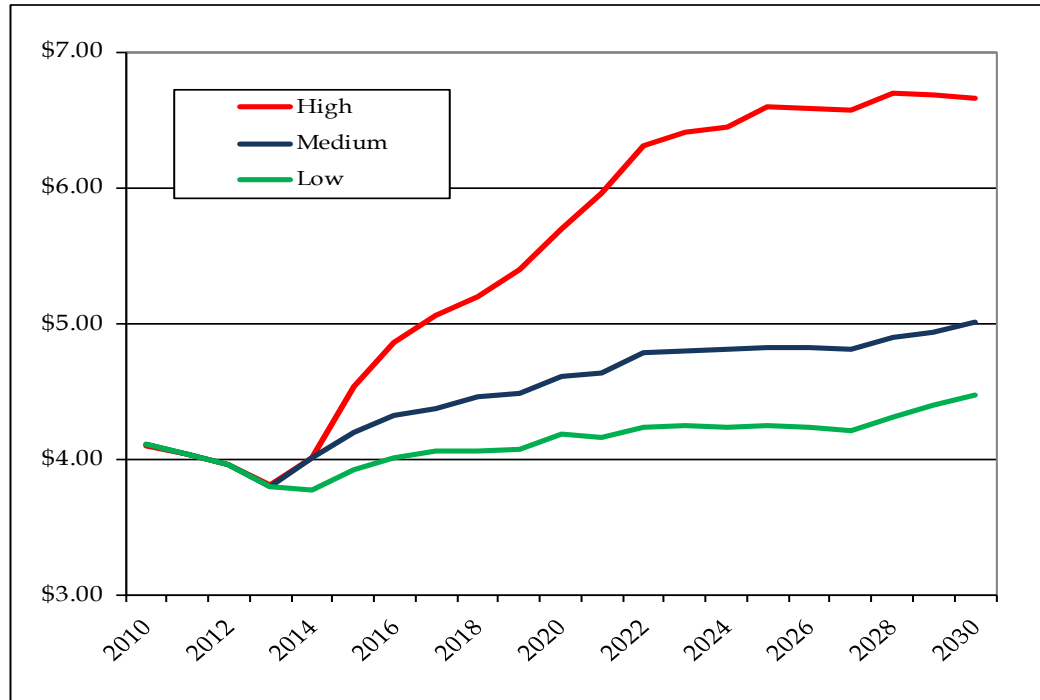
Projected prices in the southern states are similar (Figure E- 11 and Figure E- 12).

■ **Figure E- 9** New contract delivered prices Queensland aggregate, all scenarios (\$/GJ, \$2011 real)

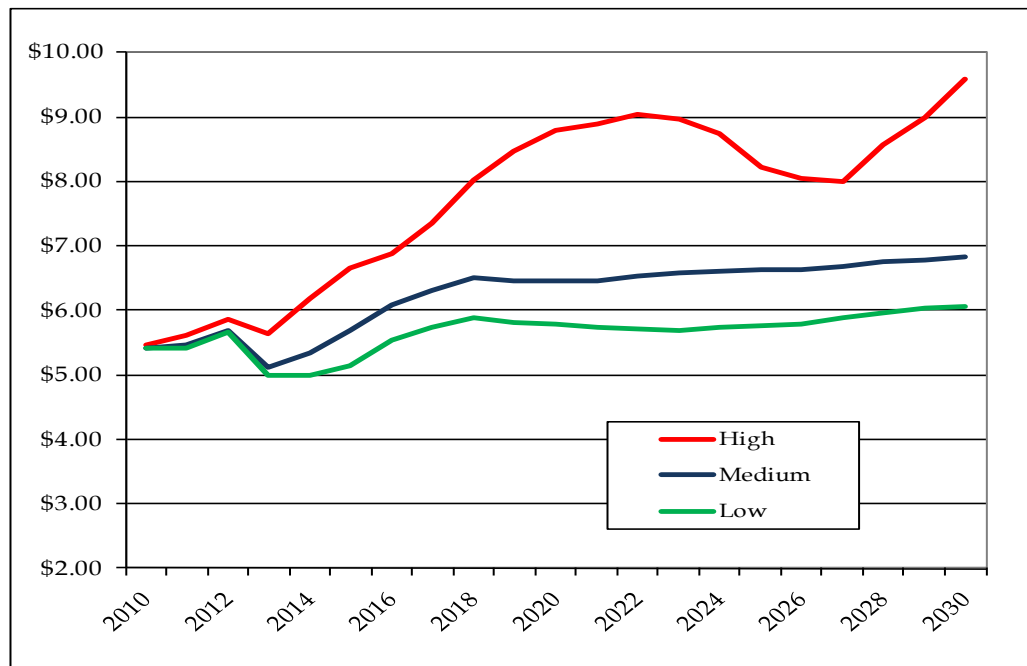




■ **Figure E- 10** Average contract delivered prices Queensland aggregate, all scenarios (\$/GJ, \$2011 real)

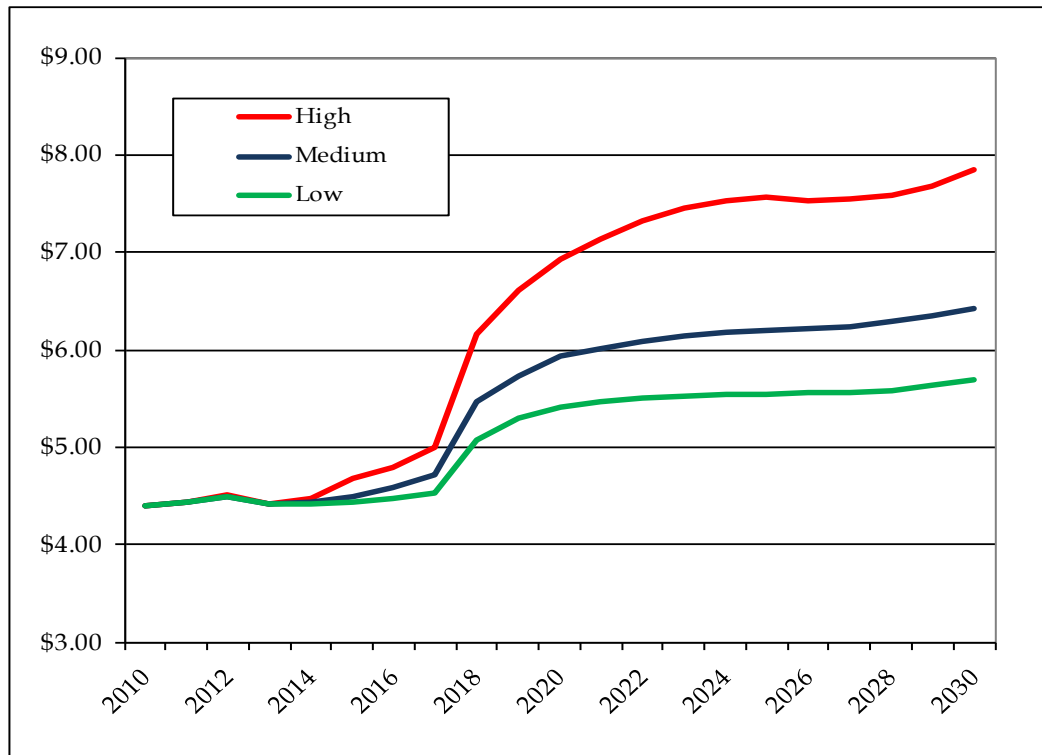


■ **Figure E- 11** New contract delivered prices Southern States aggregate, all scenarios (\$/GJ, \$2011 real)





■ **Figure E- 12** Average contract delivered prices Southern States aggregate, all scenarios (\$/GJ, \$2011 real)



Differences between the prices assumed in developing demand scenarios and the price outcomes from establishing demand supply balance result in an adjustment of demand. The new contract prices in the Low and Medium scenarios are reasonably close to the prices assumed in the demand projections, consequently the variations in new contracts are relatively low (Table E- 2), particularly the cumulative variations to 2030. In contrast the High Scenario new contract prices are above the prices assumed in the demand projections, with the result that there are more significant new contract variations.

■ **Table E- 2** Estimated cumulative new contract variation due to price increases

	Low scenario		Medium scenario		High scenario	
	By 2020	By 2030	By 2020	By 2030	By 2020	By 2030
Queensland	-17%	-5%	-17%	0%	-33%	-41%
Southern Australia	-10%	-8%	-6%	-6%	-9%	-20%

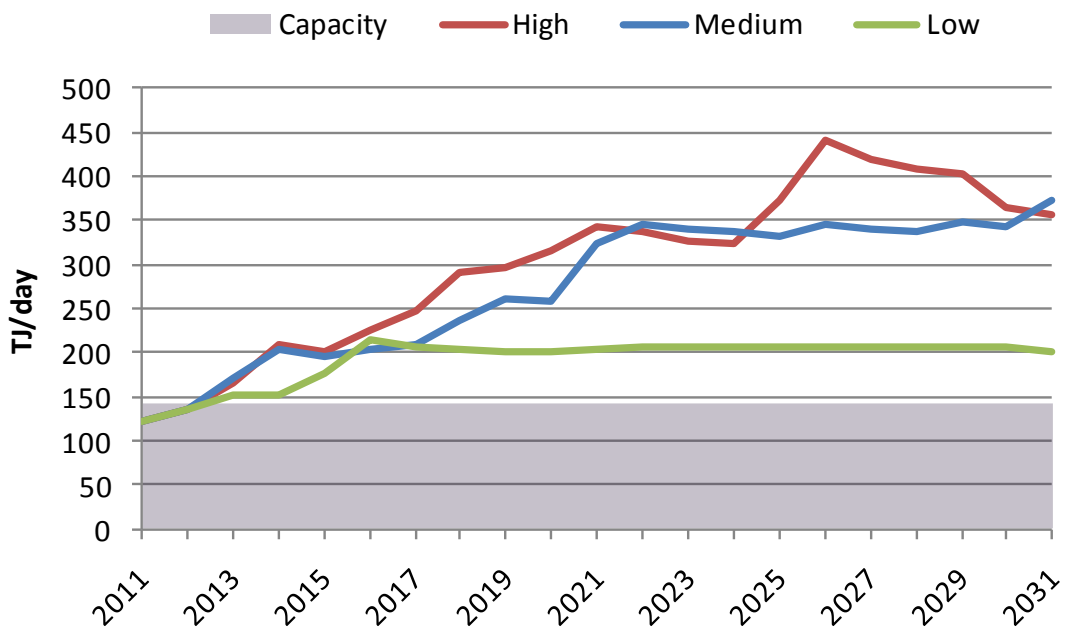


Pipeline capacity

Our projections suggest that capacity expansion will be necessary on two Queensland pipelines over the next decade:

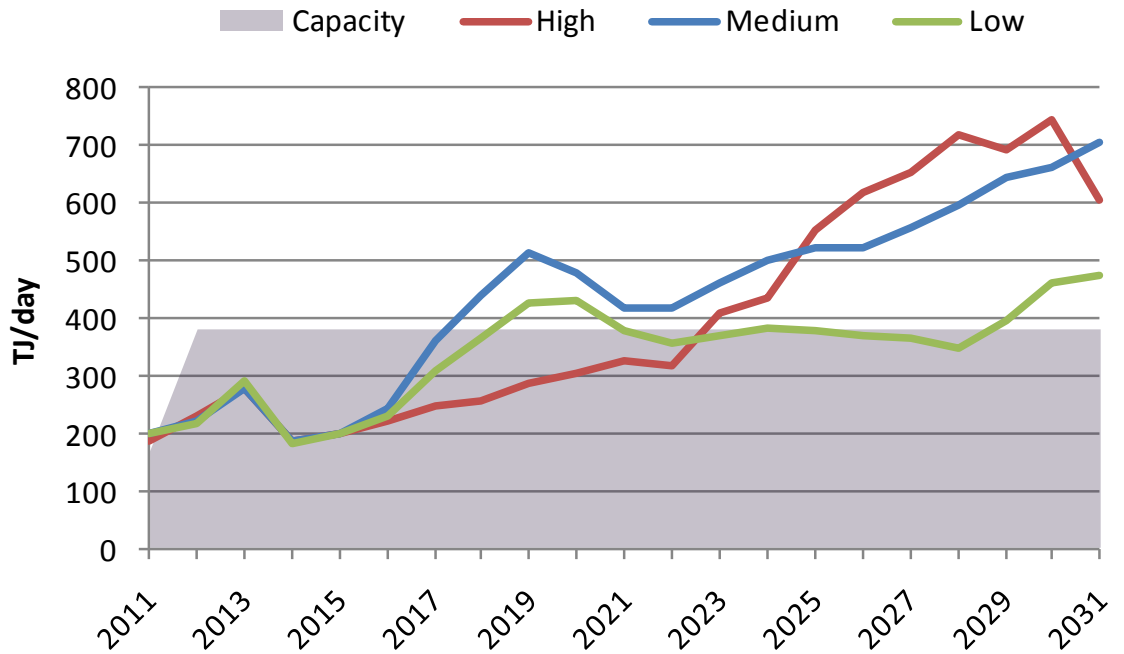
- **Queensland Gas Pipeline**
 Gladstone domestic demand projections suggest that current capacity will need to be expanded as early as 2013 to accommodate cogeneration and alumina plant expansions. The pipeline is currently operating at or near capacity.
- **South West Queensland Pipeline**
 Capacity increments are required before 2020 only in the Medium scenario, to meet growth in Queensland CSG exports to southern states. Use of CSG for LNG prevents growth in exports to southern states in the High Scenario, until after 2020.

■ **Figure E- 13 Estimated peak flow and capacity – QGP (TJ/day)**





■ **Figure E- 14** Estimated peak flow and capacity - SWQP (TJ/day)





1. Introduction

1.1. The 2011 Gas Market Review

The Gas Market Review (GMR) is an initiative of the Queensland Government that informs Government decision making in relation to the need for development of a Prospective Gas Production Land Reserve (PGPLR), more effective resource management, and the development of a more competitive Queensland gas market.

The Office of the Queensland Gas Commissioner (OQGC), within Mines and Energy, is responsible for leading the Gas Market Review process, in consultation with key gas market stakeholders, and advising government on the outcomes of these Reviews. The OQGC is also accountable for progressing government actions in response to the Reviews. The outcomes of the GMR form part of a coordinated Whole-of-Government approach to providing regular advice to Government on constraints on gas supply availability, gas market development and security of supply in Queensland and the broader Eastern Australian Gas Market.

The first GMR was undertaken in 2010 under the auspices of The Department of Employment Economic Development and Innovation (DEEDI), prior to the appointment of the Commissioner.

To support development of the 2011 GMR, the OQGC has commissioned SKM MMA, a section within Sinclair Knight Merz Strategic Consulting Division, to undertake robust gas market modelling and analysis covering the following aspects of the gas industry in Queensland and Eastern Australia more generally:

- (i) gas market supply
- (ii) demand and price variations for prescribed scenarios and time frames;
- (iii) sensitivity on certain variables;
- (iv) reserves and production;
- (v) transportation constraints;
- (vi) demand requirements;
- (vii) general market issues;
- (viii) regulatory constraints;
- (ix) drivers affecting gas prices and;
- (x) the likely impact of these constraints and drivers on future gas prices and investment in the gas market.

SKM MMA's predecessor, MMA, undertook a similar analysis for the 2010 GMR².

1. www.dme.qld.gov.au/.../Gas/ann_gas_mkt_rev_mma_report_to_deedi_23-06-2010.pdf



1.2. This study

The 2010 GMR identified that domestic gas demand-supply-price outcomes in Eastern Australia as a whole, and Queensland in particular, are critically dependent on the projected rate of development of projects to export LNG from Gladstone. Based on the trends observable at the time the 2010 GMR was produced, there did not appear to be any prospect of a material imbalance of demand and supply however.

This study focuses on the further elucidation of the key factors identified in the 2010 GMR

1. Gas demand

- a. Timing of LNG plant commitment, construction and start-up and the consequent timing of gas reserves commitments, in the context of global LNG demand and the recent Final Investment Decisions regarding two Gladstone projects (section 5)
- b. Domestic gas demand projections, the requirement for new gas contracts to support demand growth and replacement of existing contracts over time and the gas reserves need to support these contracts (section 4)

2. Gas supply

- a. The rate of development of gas reserves, importantly coal seam gas (CSG) in Queensland, and factors that may affect it (section 6)
- b. Factors that may restrict production of gas from certain reserves, such as transmission connection to markets(section 6)

3. Demand-supply balance

- a. Assessment of the physical ability of gas supply to meet projected gas demand (section 7)
- b. Projected demand-supply-price outcomes for three energy economic scenarios, using further refinements in the MMAGas model used in the 2010 GMR (section 8)

The three scenarios, labelled low, medium and high, are broadly consistent with the scenarios adopted by AEMO for the GSOO 2010.

Two features distinguish the approach used in this study from the approaches used in other studies (some recent studies are listed in the text box below):



1. A focus on dynamics and the timing of resource development relative to demand. Our approach views the gas market as a market for long-term contracts negotiated in advance of actual supply. Supply competition in this market is between suppliers who have 2P reserves available to commit to contracts at the time of negotiation.
2. Projection of price outcomes derived from the demand-supply balance. Price depends on supply costs, levels of competition and customers' willingness to pay and reflects the tightness of supply.

Other Recent Gas Demand-Supply Studies³

In addition to the 2010 GMR a number of other recent studies have addressed gas demand and supply in Australia and/or Eastern Australia:

- 1) "Gas Statement of Opportunities" (GSOO) published by AEMO in 2010
- 2) "State of the Energy Market 2010" published by AER in 2010
- 3) "Australian Energy Resource Assessment" (AERA), published by DERT, Geoscience Australia and ABARE in March 2010
- 4) "Gas Market Report" prepared by KPMG for APPEA and released in May 2010

These studies all conclude that there are sufficient gas resources to meet anticipated levels of demand, including exports, over the next 20 years. The AER study discusses the price impact of higher supply costs and gas exports but does not present any price projections or estimates of price impacts. The AEMO GSOO report considers details of demand and supply including timing of reserves development and production/pipeline capacity requirements, but also does not present any price projections or estimates of price impacts. The AERA and the Gas Market Report do not address details of demand supply balances.

³ All of these studies can be downloaded from the publishers' websites



1.3. Stakeholder consultation

The OQGC has undertaken extensive consultation with stakeholders as part of the 2011 GMR process. A key element of the consultation has been meetings with stakeholders, at which discussion has focussed primarily on:

- Stakeholder project development, both demand side and supply-side
- Issues regarding domestic demand and supply, including counterparties willingness to buy or sell gas

The discussions have provided OQGC and SKM MMA with an excellent understanding of issues faced by stakeholders and of current gas market directions. All stakeholder information has been provided in confidence however and none has been reproduced in this report unless independently sourced from public reports.

Stakeholders have also commented on the Draft Report issued on 31st May 2011 and their comments have been taken into account where appropriate.

1.4. Confidentiality

The methodology used to derive the projections in this report has been based on modelling, using material from SKM MMA data bases or in the public arena. The results of this modelling are not confidential.

1.5. Uncertainty of forecasts

This report has been commissioned by OQGC and prepared specifically for OQGC by SKM MMA. All analyses, results, conclusions and recommendations contained in this report are based on OQGC's specific instructions to SKM MMA and on a scope of work and methodology agreed between OQGC and SKM MMA.

This report contains a number of forward looking forecasts and statements. SKM MMA makes evaluations and interpretations based upon SKM MMA's best judgement of inherently uncertain factors and processes. Nevertheless, since all interpretations and evaluations are opinions based solely on inference from available data, SKM MMA cannot and does not guarantee the accuracy or correctness of any interpretation and evaluation. SKM MMA provides the report as the result of a forward looking assessment at a particular point in time using the models and data that were available at that time and the methodology and scenarios agreed with OQGC.



2. Gas Market Background

2.1. Historical development

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has a growing domestic market, estimated at 704 PJ in 2010, supported by substantial conventional and coal seam gas (CSG) reserves – 2P reserves at 31/12/2010 are estimated at 43,540 PJ. Regional breakdowns of these figures are shown in Table 2-1.

■ **Table 2-1 Gas demand and reserves by state, 2010 (PJ)**

	NSW	Victoria	SA	Tasmania	Queensland	Total
Demand	148	221	106	16	214	704
Reserves	2,879	6,758	1,414	313	32,176	43,540

Source: Demand: AEMO Bulletin Board; Reserves: Table 6-6

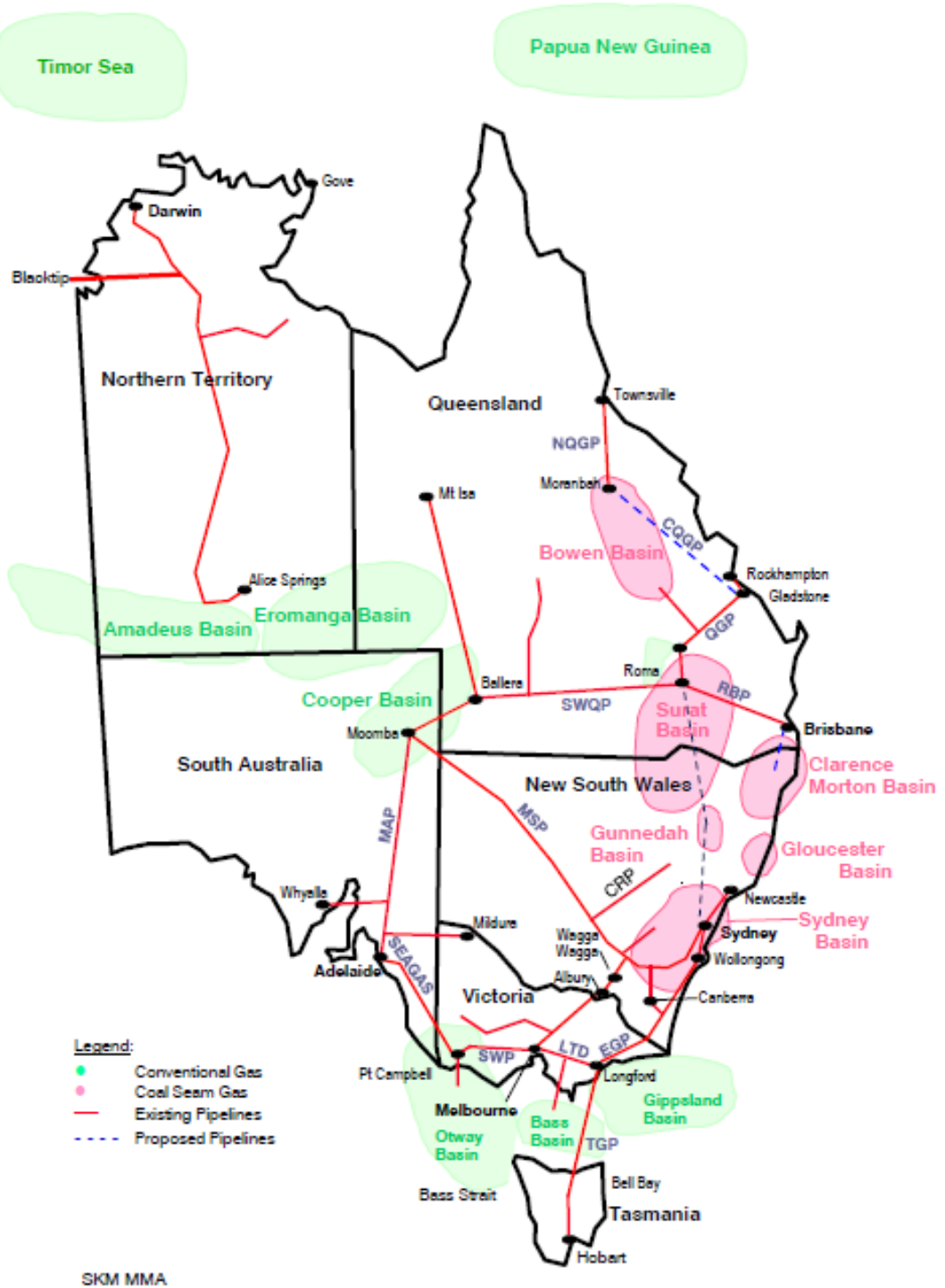
Demand and supply patterns in this market have operated in isolation from other gas markets in Australia and overseas because to date there have been no gas exports from or imports to the region. Recent growth of CSG reserves, to levels in excess of foreseeable domestic demand, has led to a number of proposals to monetise reserves by exporting LNG to markets in Asia and elsewhere. These export projects have already begun to change the domestic market, both in terms of the demand-supply dynamics and the nature of the participants, who now include global energy companies such as BG Group, Conoco Phillips, Petronas and Shell, and large offshore gas purchasers such as China Petroleum Corporation, Kogas and PetroChina. Further changes are likely in future.

The prospect of exports emerged relatively suddenly and unexpectedly, following a long history of perceived excess of demand over local supply and a corresponding history of proposals to import gas from the North West Shelf in Western Australia, from Papua New Guinea and from the Timor Sea. All of these proposals have been deferred because of unforeseen growth in Eastern Australian gas reserves and supply, most recently the CSG reserves in Queensland.

The majority of Eastern States sub-markets are now served by multiple basins and/or pipelines, the key exception being Townsville (Figure 2-1). Planning for a pipeline between Moranbah and Gladstone, which would link Townsville to other supplies, is well advanced but construction appears to be contingent upon LNG development in Gladstone using gas from the Moranbah area. The QSN Link between Ballera and Moomba, which commenced operations in February 2009, directly links Queensland supply to the southern states, replacing the previous swap arrangements.



■ Figure 2-1 Gas basins and pipeline infrastructure, Eastern Australia





The dominant transactions in the Eastern Australian gas market are long-term gas sales agreements (GSAs) between gas producers and buyers such as retailers, large industrial users and generators. Over time the duration of long-term contracts has covered a wider range, running from 3 years to 15 years in contracts entered over the last decade. There is limited public information on gas contracts but the basic details such as term and average volumes are known for the majority of the significant contracts. Contract prices are less well known but can often be estimated – most contract prices are CPI indexed and undergo periodic reviews to ensure they remain at “market” levels, though without a recognised market price, reviews can be prolonged.

Shorter-term bi-lateral contracts are also used but there is almost no public information about them. In particular, short-term markets appear to have insufficient depth to support a price index, in contrast to short-term markets in the US and Europe, where many trading hubs have associated benchmark prices, the best known being the Henry Hub in Louisiana. Many longer term contracts in the US are now indexed to the Henry Hub price, overcoming the difficulty of setting long-term prices that remain in line with the market.

There is a gas pool in Victoria operated by the Australian Energy Market Operator (AEMO) for the primary purpose of balancing the transmission/distribution system – the pool price is used to settle injection/withdrawal imbalances. Bidding into the pool is compulsory for all transmission/distribution system users, most of whom are retailers buying gas from producers under GSAs. The short-term trading markets (STTMs) recently established by AEMO in Adelaide and Sydney and about to start up in Brisbane are similar and they share many features with the Victorian approach. In general the pool prices are determined by the prices set in the GSAs rather than vice versa, though at least one proposed GSA has included a price linked to the Victorian pool price. A futures market based on the Victorian spot price is operated by the ASX and offers prices three years ahead. In general however linking contract prices to pool prices creates a circularity that may only be resolved by producers directly participating in the pool or in short-term bi-lateral trading and the creation of related price benchmarks.

The level of gas producer competition has until now been sufficient to maintain price levels for new GSAs in the south-east and to reduce prices in some Queensland sub-markets. It is widely believed that gas exports will lead to higher domestic prices but price rises are likely to be constrained by domestic users’ willingness to pay.

2.2. Factors influencing future directions

The primary factors influencing the future direction of the gas industry in Eastern Australia are perceived to be LNG exports and carbon pricing. In the longer term, unconventional gas other than CSG may become an important factor.



2.2.1. LNG exports

The potential impacts of LNG exports from Eastern Australia are outlined below. Further analysis of this sector is provided in section 5

2.2.1.1. Availability of gas for domestic contracting

The LNG projects will use substantial volumes of gas, approximately 220 PJ/yr per 3.5Mtpa train, so the four trains already committed (two each by BG Group and GLNG) will equal the Eastern Australian domestic market in annual volume terms when they are fully operational in 2016. Each project is likely to require a 2P reserve dedication equalling the volumes of gas committed to buyers in off-take contracts, which typically have a term of 20 years. The committed projects therefore require approximately 17,600 PJ plus further margins (refer to section 6.6) and other projects in planning more than double this figure.

At the start of LNG project development in 2007 this dedication requirement was well in excess of proved 2P reserves (in aggregate and on individual project bases) and project proponents have therefore put considerable effort into reserve development, alongside engineering design and marketing. Project proponents have significant incentives to develop multiple projects as quickly as possible, in the form of economies of scale for multiple trains and construction cost savings for sequential train development on a single site.

Proponents therefore have strong incentives not to sell incremental domestic gas contracts, which would also need reserve dedication, until sufficient reserves had been appraised for two or three LNG trains. Non-proponent gas producers may also be disinclined to enter new domestic contracts for a period of time, until they can determine whether they will be able to sell some gas for export or until the domestic price response to exports becomes clearer.

Stakeholder consultation for the 2011 GMR has revealed widespread difficulties faced by Queensland domestic gas buyers in getting substantive discussion with gas producers regarding new long-term contracts, with two exceptions: for shorter term contracts to 2014-5 with CPI indexation; and for contracts at high prices involving oil price indexation, replicating LNG netback prices. The level of interest of producers reportedly declined after the first CSG-LNG project reached FID, which re-confirmed the plausibility of the projects.

We understand that at least one low volume, shorter term contract has recently been entered, though its structure is unknown to us. We are not aware that any long-term domestic contracts have been signed at LNG netback level prices to date.

2.2.1.2. Link to higher value market

Linked to the above concern is the widely stated expectation that when exports commence, domestic pricing will inevitably move to export price parity, as measured by the netback value of



LNG. While this is a potential outcome, it is clearly not going to occur if exports are well below potential.

Oil indexation of gas prices will cause considerable difficulties for buyers who produce commodities or electricity when oil prices rise faster than the prices of the outputs produced by buyers. Similarly, prices linked to outputs produced by buyers could be equally unsatisfactory for gas producers, both leading to more frequent triggering of price reviews. Oil indexed prices with caps and floors related to buyer outputs may be workable but ideally a more liquid short-term market might better set a price which balances the market for supply and demand.

2.2.1.3. Qualitative market changes

The LNG projects have resulted in consolidation of many CSG producers, though there is still more upstream competition than in the pre-CSG era. All the major projects now also involve overseas players, with two projects, QCLNG and Arrow Energy, under 100% foreign control, by BG Group and Shell/PetroChina respectively.

These changes will certainly result in different decision processes regarding investment in CSG production compared to the formerly small CSG producers and may also result in different outcomes due to the different priorities of the new owners.

2.2.1.4. Gas trading

Balancing gas supplies to a group of large LNG plants will most likely result in an increase of trading among LNG participants and other gas traders. The ability to trade could be reinforced by availability of gas storage at the confluence of major pipelines, for example at Wallumbilla, creating a genuine gas hub similar to the Henry Hub, the primary spot and futures price setting hub in the US. A market hub at Wallumbilla has the potential to substantially improve market liquidity and transparency.

2.2.2. Carbon pricing

In the electricity sector carbon pricing has the effect of making gas more competitive with high carbon coal, which currently dominates base load generation in Eastern Australia, but simultaneously less competitive with low or no carbon options such as renewables. Whether carbon pricing leads to an increase in gas use or not is therefore determined by the balance of pressures from either side. These pressures have also been adjusted, both in favour of and against gas, for example by the Queensland GECS scheme and by the RET. On balance however in most markets and scenarios it appears that carbon pricing favours gas in the period to 2030, after which new technologies such as clean coal may depress gas use for generation.

A secondary effect of carbon pricing on gas is the expected growth of peaking gas generation plant to support intermittent renewable generation such as wind. Peaking gas plant will require more



flexible gas supply, which may necessitate investment in gas storage (underground, LNG or linepack pipelines) or liquid fuel back-up.

Carbon pricing will also increase the end-use cost of gas for other usage, potentially reducing usage in non-generation sectors. However here too care must be taken to fully account for the substitution opportunities opened up by carbon pricing.

In terms of the gas wholesale market however the impact will most likely be limited as the only costs borne in this market are the carbon costs of gas used in production and pipeline compression, the carbon costs of combustion or feedstock use being paid by end-users or retailers.