8. Economic demand-supply balance and price projections

8.1. Economic demand-supply and pricing methodology

The economic demand-supply balance and price projections for this study have been derived 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, with opportunities to exercise market power
- 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.

MMAGas has been developed over a period of eight years, to provide realistic assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market:

- The "gas market" in MMAGas is the market for medium to long-term contracts between producers and buyers such as retailers or generators
- MMAGas combines information on gas demand and committed contracts to estimate the demand for new contracts as described in section 7.1
- The PJ/yr capacity of each producer to supply new contracts from its available uncontracted 2P reserves is based simply on reserves available divided by contract term
- Allocation of new GSAs in each market zone to gas producers is based on the assumption that each producer seeks to control its volumes and prices to maximise its profit (revenue less cost of production) subject to constraints imposed by its competitors and its capacity to produce
- This competition between producers is represented as a Nash-Cournot game with the role of buyers replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as production cost inputs, so the profit in each market zone is the volume times (delivered price less delivered cost).
- A gas producer in MMAGas is generally a joint venture controlling major resources, such as the Cooper Basin JV (Santos, Beach and Origin Energy). Some resources effectively controlled by a JV but not part of it are added to the JV's resources, such as the Kipper field in Gippsland, part owned by Santos, which is outside the BHPB-Exxon JV. Others however are not, for

example the part of the Fairview field not owned by GLNG is not considered as part of the GLNG JV's reserves.

Gas producers, i.e. the JVs, are assumed to make joint sales and to compete fully with one another, even when the JVs have some common ownership. This may overstate the level of competition, however in practice this is offset by additional competition created by separate selling within some JVs.

MMAGas outputs have been benchmarked against gas production and transmission flows reported by AEMO on the "Bulletin Board" and against new GSA prices wherever such information becomes available. Model parameters for the current implementation have been estimated so that its outputs replicate negotiated contract price and volume outcomes over the past seven years. It is noted that historical contract prices have covered a narrow range relative to potential future prices and MMA recognises that, as with all approaches to projection, MMAGas ability to accurately project results outside of its development data range is not guaranteed. The projections made under any specific set of assumptions should not be regarded as 100% precise, even though they are expressed as a single set of numbers.

One of the most critical assumptions in MMAGas is that negotiations for new contracts take place four years before the contracts start, to enable new capacity to supply contracts to be constructed (refer also to section 7.2). This is consistent with market behaviour to date, ensures that all uncontracted reserves can be considered for new contract and thereby leads to the lowest prices consistent with the concentration of reserve ownership. The availability of reserves for new domestic contracts is affected by LNG project reserves build-up as described in section 7.3.

The current implementation of MMAGas represents the eastern states market as up to twenty separate producers competing in nine separate domestic market zones plus one LNG export zone. Further details on MMAGas are provided in Appendix A. Only detail changes have been made to the model since the 2010 GMR.

8.1.1. LNG contract demand function

The influence of LNG prices on domestic prices is specified via the LNG contract function, which specifies the value available to producers from supplying LNG projects. The model can be run in either of two modes: in the first mode, contracts within the JVs developing the LNG projects are considered pre-contracted and only the incremental project requirements are competed for (where project JV reserves are insufficient); in the second mode, all project requirements are competed for. The modes do not affect the supply demand balance and yield very similar price outcomes.

The LNG demand function assumes that gas producers and liquefaction owners share in the LNG netback value at Gladstone, or at the gas field, depending on the point of sale. The netback value is the delivered price of LNG less the costs of liquefaction and shipping. Netback value can be calculated using short or long-run costs – as the impact being estimated in this study is that on long-term domestic gas contracts, long-run costs are appropriate. Netback value will also vary between LNG projects, however as we are unable to differentiate between the costs/revenue of the various projects, a single value is used in this study.

The delivered price of LNG depends primarily on the price of crude oil (using the Japan Customs-cleared Crude (JCC) measure, also known as the Japan Crude Cocktail) and the $US/$A conversion rate, and secondarily on the link between LNG prices in $US/mmbtu and the JCC price in $US/bbl. For this study we have used a direct linkage without a cap or floor, namely LNG Price = 0.15 * JCC price. This formula is believed to apply to GLNG contracts[32] and implies that at $US80/bbl oil, the LNG price is $US12/mmbtu.

Based on GLNG quoted costs[33], SKM MMA estimates that liquefaction plus shipping costs would range from $5.35/GJ at $US/$A = 1.00 up to $9.19/GJ at $US/$A =0.60 (the exchange rates being applicable during construction, when most costs are incurred). The resulting netback prices at the oil prices and exchange rates in the three scenarios are shown in Table 8-1. The values are slightly lower than comparable estimates used in the 2010 GMR because of escalation in liquefaction costs.

Table 8-1 LNG Netback values at Gladstone

	Low Scenario	Medium Scenario	High scenario
JCC price ($US/bbl)	$60	$100	$140
Exchange rate ($US/$A)	0.60	0.80	1.00
LNG Netback value ($A/GJ)	$7.45	$12.89	$16.15

For the purposes of constructing the LNG demand function it is assumed that the purchaser will not be prepared to pay more than the netback value at Gladstone for gas delivered to Gladstone, because a higher price would render the LNG project uneconomic, i.e. effectively demand for LNG contracts is zero at delivered prices above netback. It is also assumed that GSA sellers will be unwilling to sell at a price below their cost of production plus transmission to Gladstone, which for

[32] GLNG Project FID, 13 January 2011, and Santos Investor Presentation, March 2011, both available at www. Santos.com
[33] Ibid

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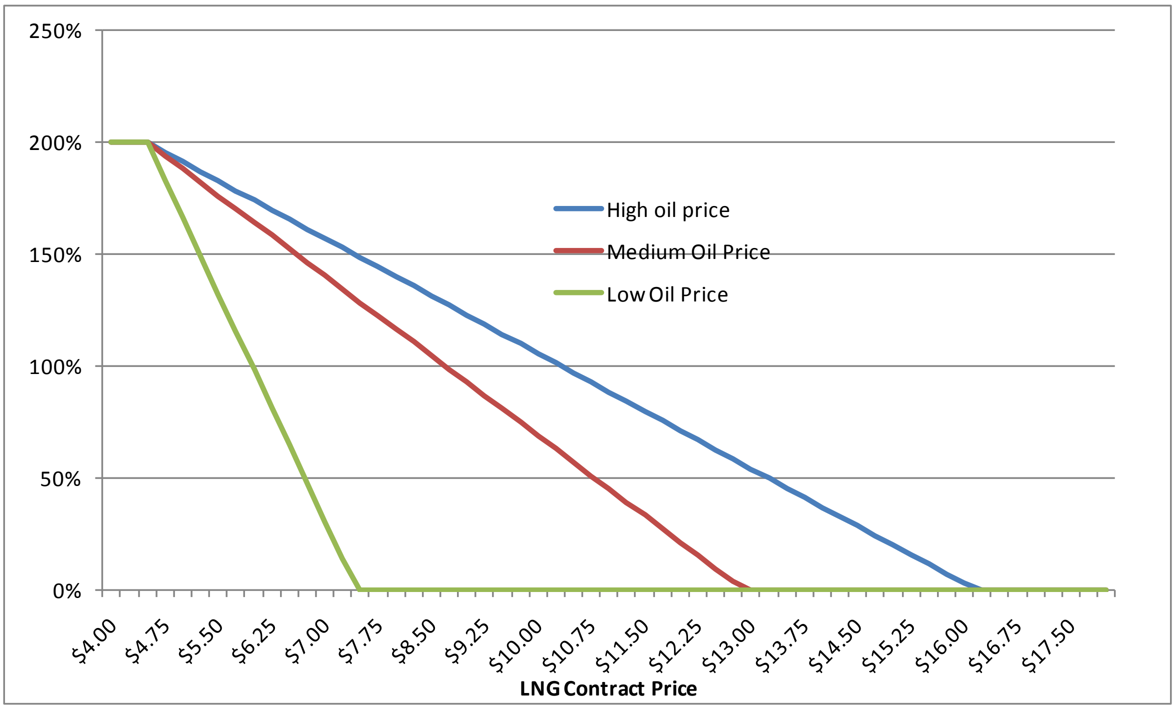
typical CSG producers would be in the range $4/GJ to $5/GJ. A value of $4.50/GJ is assumed in all modelling. The LNG demand function used in the Nash-Cournot model assumes that forecast demand is met at a price mid-way between these extremes, as illustrated in Figure 8-1.

▪ **Figure 8-1 LNG contract demand functions**



Refer to text for explanation

8.1.2. Further assumptions

A further key assumption in regard to modelling the demand-supply balance and future prices of gas in Eastern Australia is the number of competing gas producers and the gas resources available to them. The number of producers competing in the Eastern Australian gas market is currently modelled as the 18 joint ventures represented in Table 6-6. The assumption that these joint ventures are the competitive entities in the market is a reasonable approximation of reality – in some cases competition between JVs may be restricted by participation of some companies in both JVs but this may be offset by competitive marketing within JVs. It is noted that transmission costs present a barrier to producers competing in all nine zonal markets.

The current uncontracted reserves of the producers are shown in Table 6-6 and their projected future reserve additions are discussed in section 6.5. Changes in these quantities over time, as further gas is contracted and reserve additions are made, are projected using MMAGas using the maximum growth rates and resource constraints discussed in that section. MMAGas can also accommodate changes in industry structure such as gas reserve additions in new provinces, market entry by new producers and reductions in the number of producers due to mergers or takeovers. However these changes are not calculated within the model but must be input as data – our base case assumption is that the number of producers remains static and only their resources and costs change.

The modelling assumes that all producers with uncontracted reserves who are not engaged in building reserves for export will compete to sell to the domestic market. In view of the difficulties currently being experienced by domestic buyers in engaging producers in discussions about long-term domestic gas contracting it is legitimate to question when producer interest in the domestic market will return. In the Low and Medium scenarios this would most likely be no later than 2013 by which time the LNG opportunity would be seen to be diminishing and uncontracted reserves would start to build up as per Figure 7-9. In the High Scenario it could be later, in which case more restricted competition could lead to higher prices than projected in the following sections.

8.2. Gas supply projections

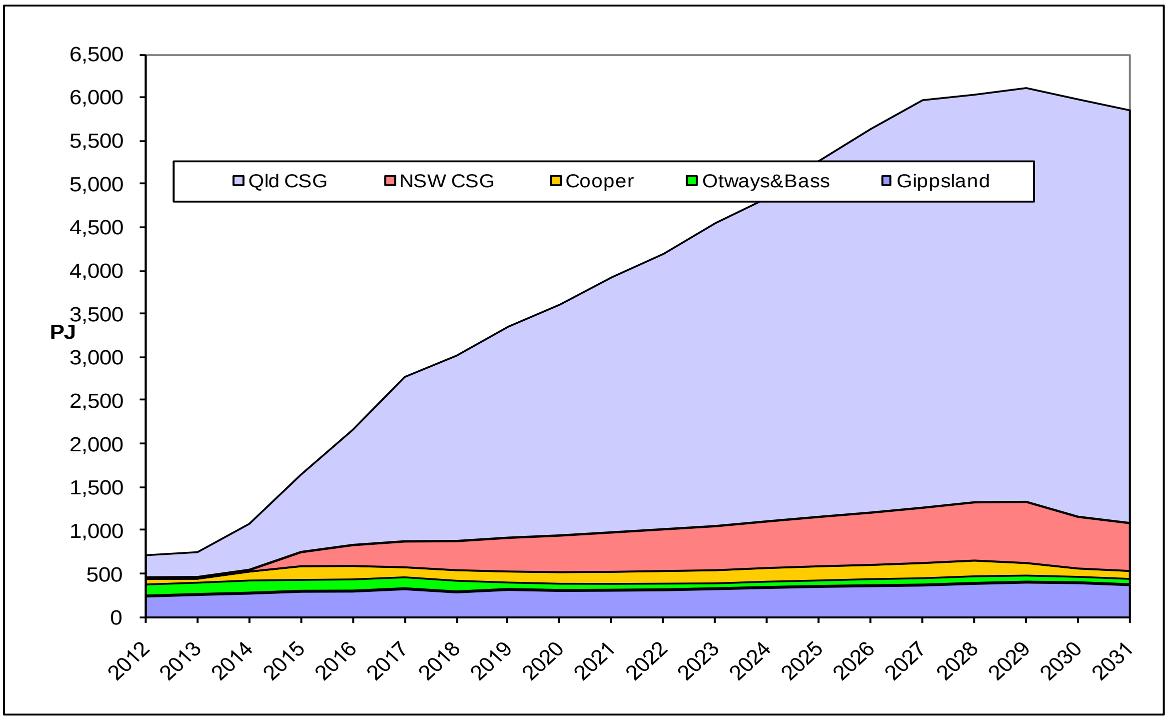
8.2.1. Domestic plus LNG

The projected aggregate gas supply patterns for Eastern Australia, including LNG export requirements, for the High, Medium and Low scenario demand projections presented in sections 4 and 5, are depicted in Figure 8-2, Figure 8-3 and Figure 8-4.

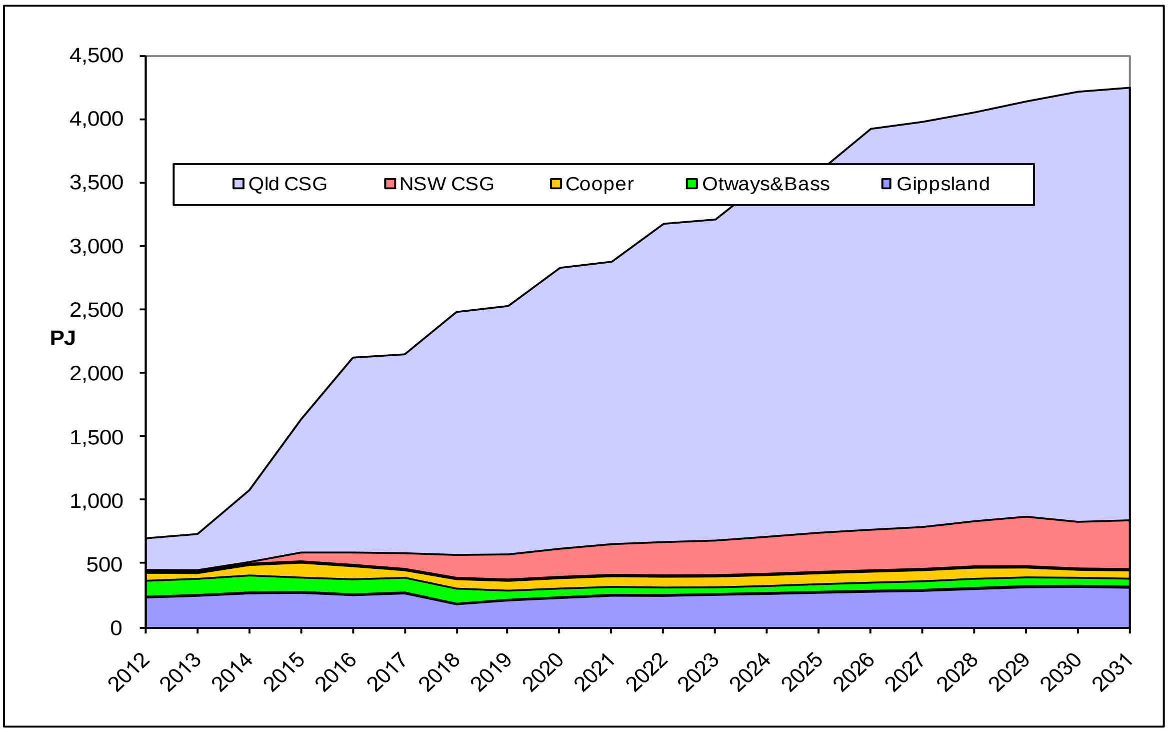
Key aspects are:

- Overall dominance of Queensland CSG production, which supplies the most of the LNG exports
- Strong growth in NSW CSG, mainly from the Gunnedah basin and particularly in the High Scenario
- A modest resurgence in production from the Cooper Basin owing to the sale of gas to GLNG
- Modest growth in Gippsland Basin production
- Declining production in the Otway and Bass basins owing to declining reserves
- In the High Scenario, an overall decline in production at the end of the period owing to the rise in prices at that time (Figure 8-11 and Figure 8-12)

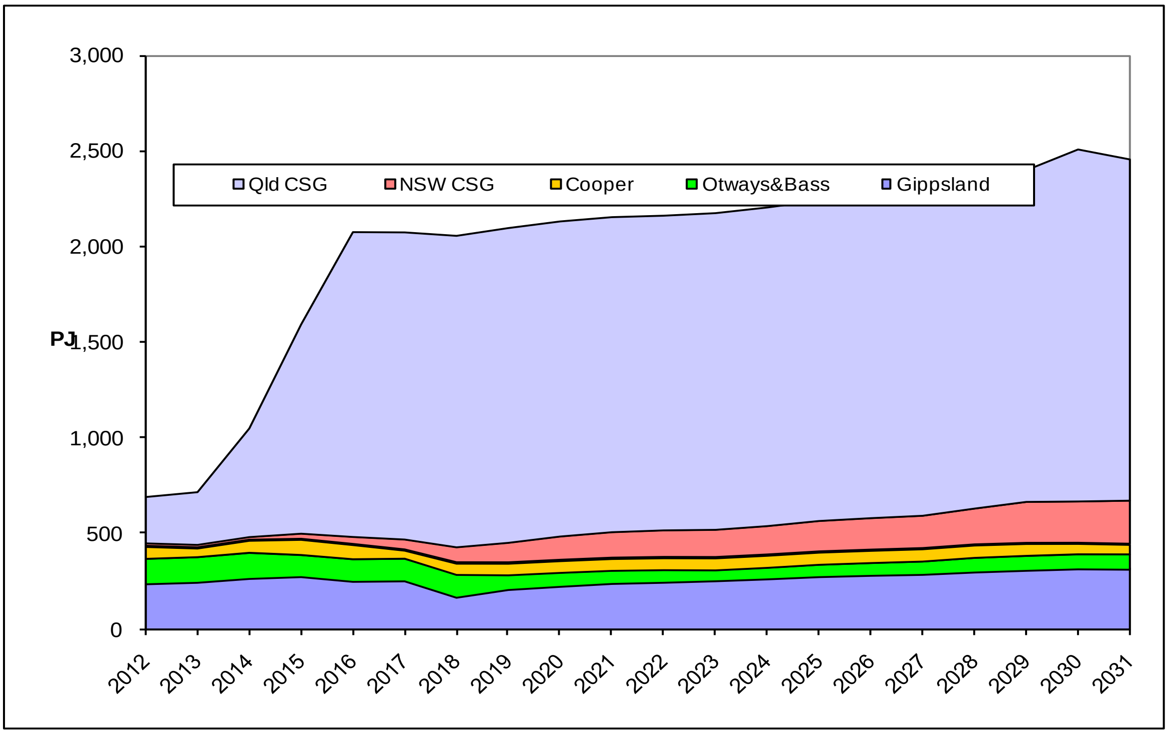
- **Figure 8-2 Projected gas supply, Eastern Australia domestic plus exports, High scenario (PJ)**



- **Figure 8-3 Projected gas supply, Eastern Australia domestic plus exports, Medium scenario (PJ)**



▪ **Figure 8-4 Projected gas supply, Eastern Australia domestic plus exports, Low scenario (PJ)**



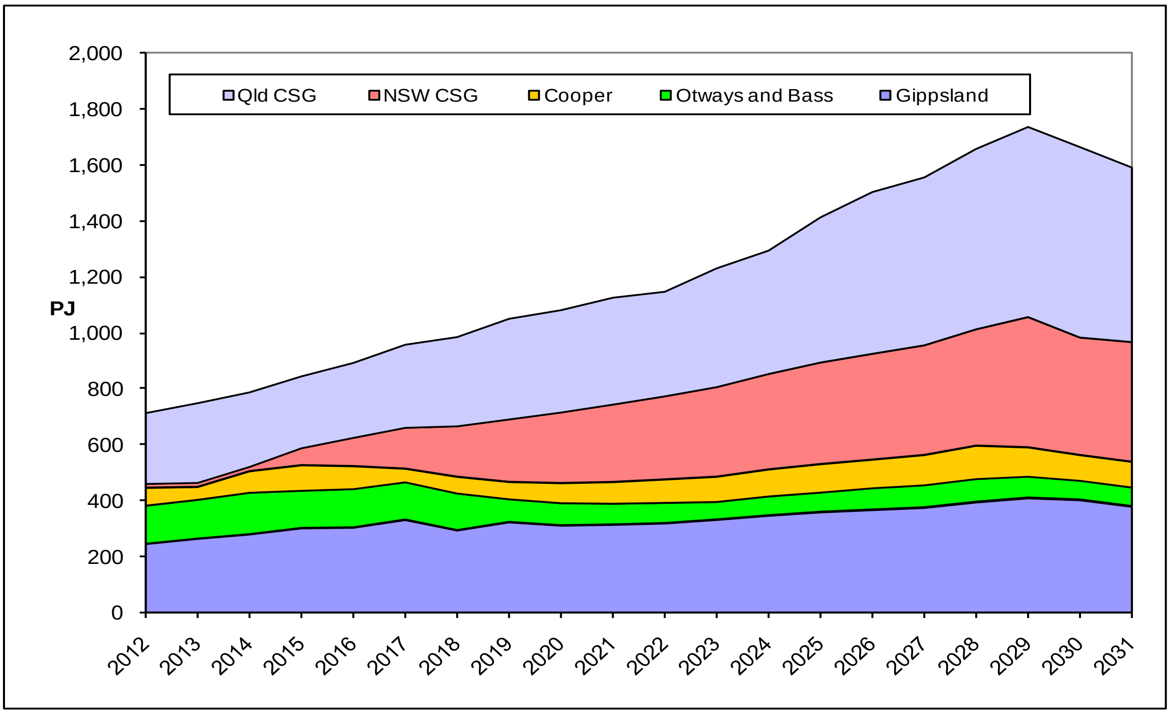
8.2.2. Domestic, Eastern Australia

The projected aggregate gas supply patterns for Eastern Australia, domestic only, for the High, Medium and Low scenario demand projections presented in section 4, are depicted in Figure 8-5, Figure 8-6 and Figure 8-7.

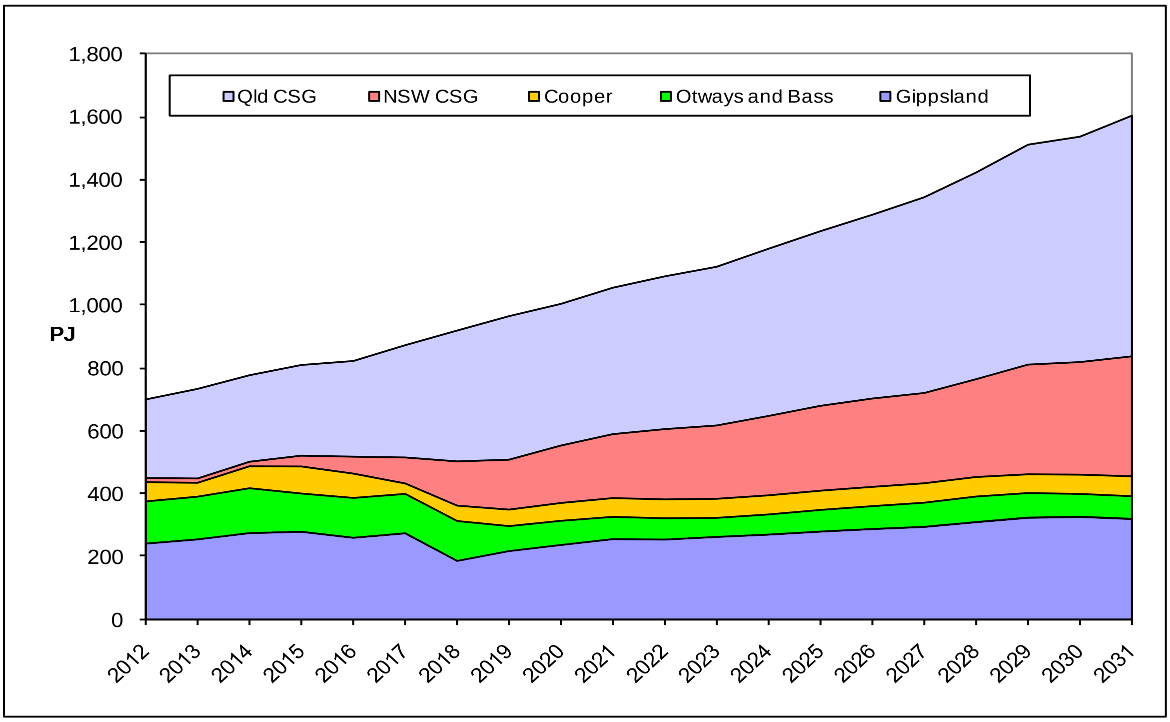
Key aspects are:

- Relatively modest growth in Queensland CSG relative to reserves owing to dedication of reserves to exports, particularly in the High scenario
- Rapid growth in NSW CSG production from about 2015, from the Gunnedah, Gloucester and Clarence Moreton Basins
- Steady Cooper Basin production, particularly in the High scenario
- Long term increases in Gippsland production due to producers outside the dominant Exxon-BHPB JV. These increases are substituting for Otway and Bass Basin production supplied to Victoria and South Australia.
- In the High Scenario, an overall decline in production at the end of the period owing to the rise in prices at that time (Figure 8-11 and Figure 8-12)

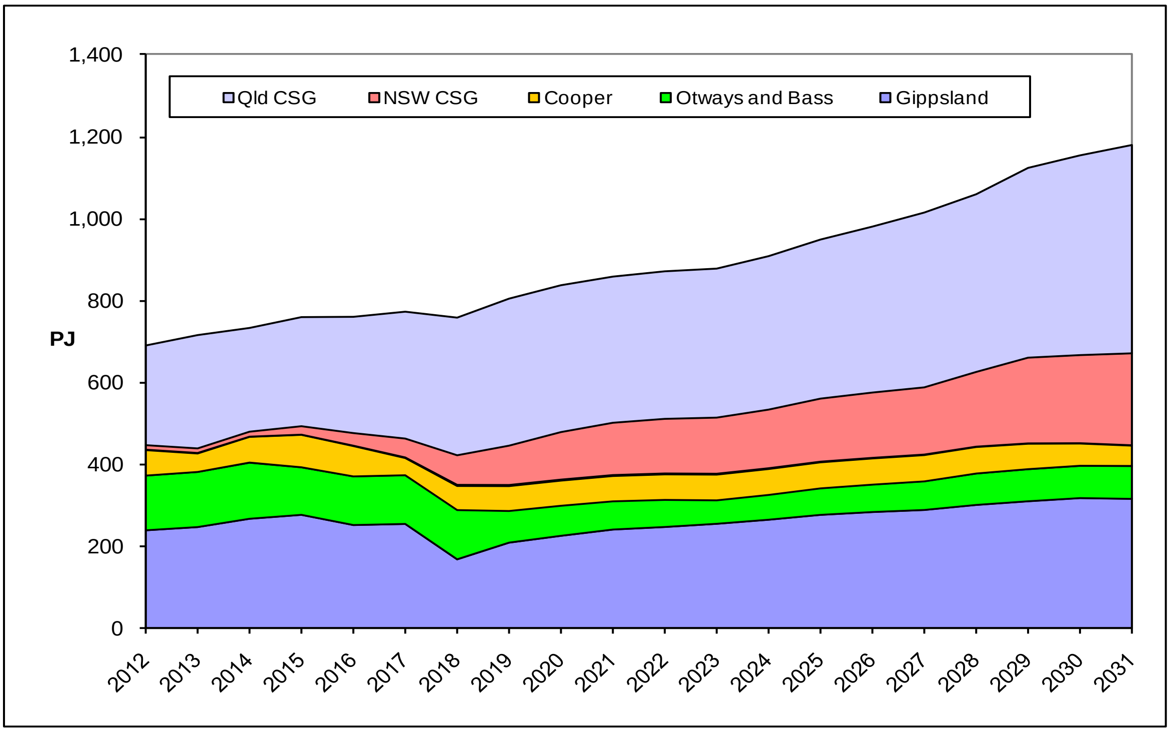
- **Figure 8-5 Projected gas supply, Eastern Australia domestic only, High scenario (PJ)**



- **Figure 8-6 Projected gas supply, Eastern Australia domestic only, Medium scenario (PJ)**



■ **Figure 8-7 Projected gas supply, Eastern Australia domestic only, Low scenario (PJ)**



8.2.3. Domestic Queensland

The projected aggregate gas supply patterns for Queensland domestic only, for the High, Medium and Low scenario demand projections presented in section 4, are depicted in Figure 8-8, Figure 8-9 and Figure 8-10.

Key aspects are:

- Considerable variation between scenarios.
- In the High scenario:
    - The Queensland CSG contribution declines initially and then grows
    - NSW CSG grows substantially
    - Cooper Basin gas re-enters the market
- In the Medium and Low scenarios Queensland CSG dominates supply, though NSW CSG and Cooper Basin gas do enter the market in 2014 and 2015 owing to a relative shortfall of Queensland CSG at that time.

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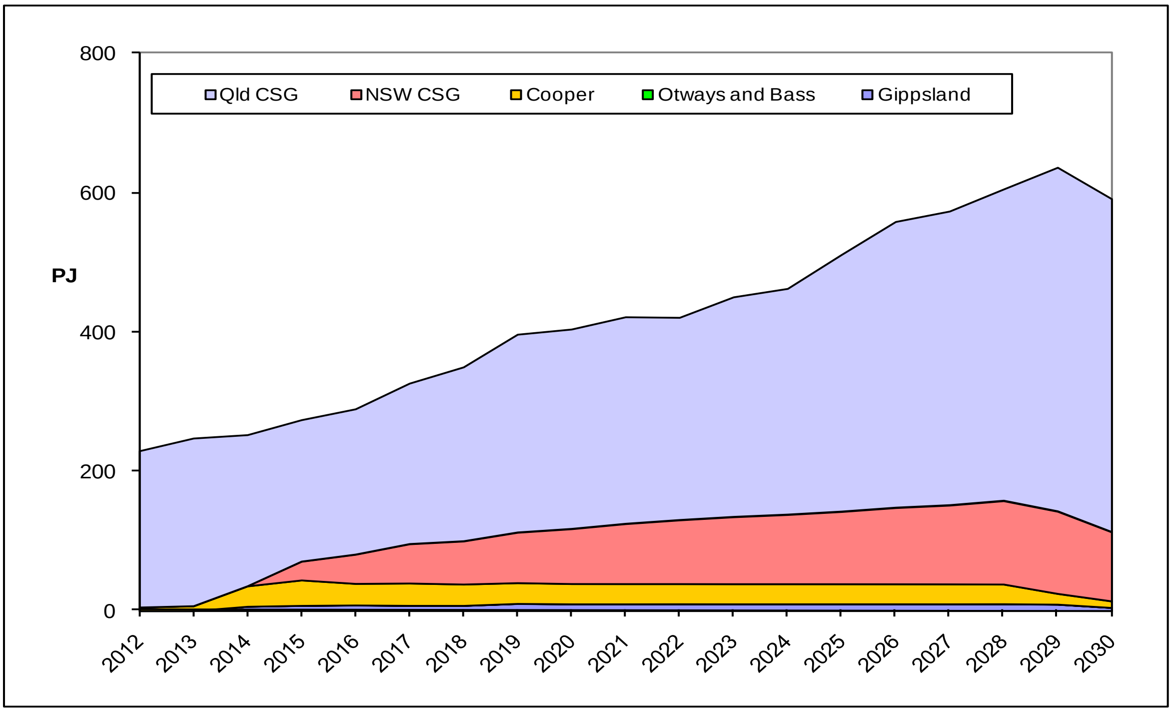
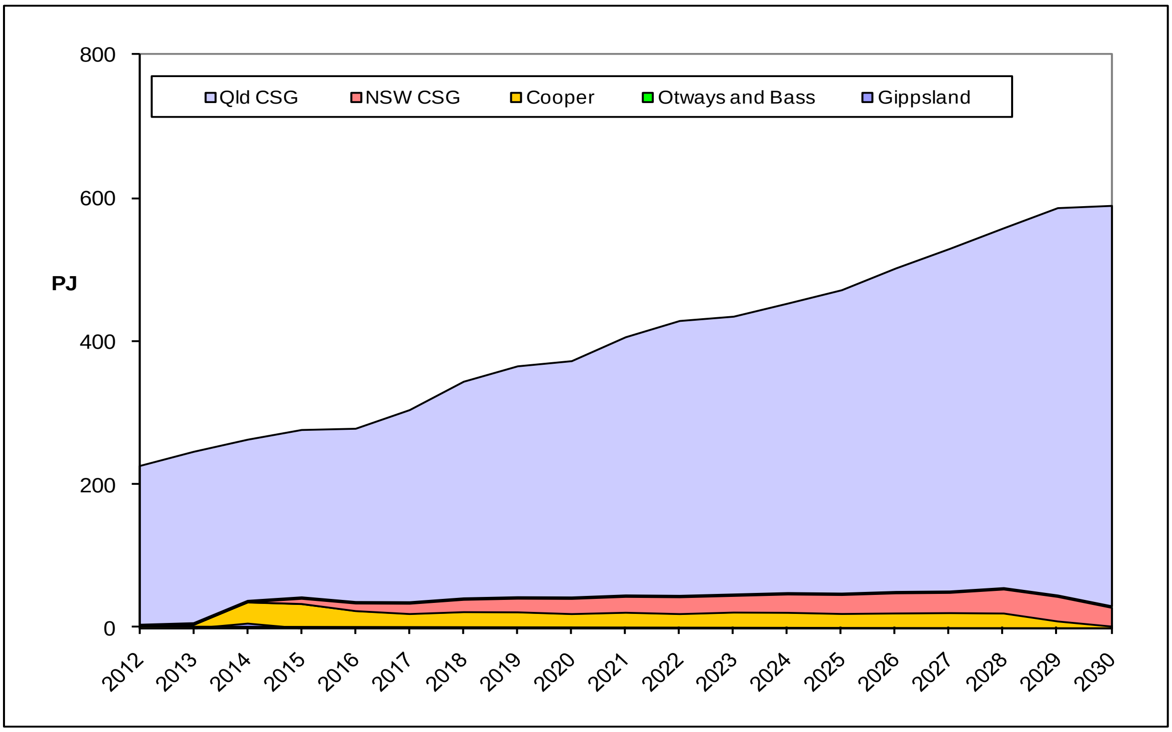
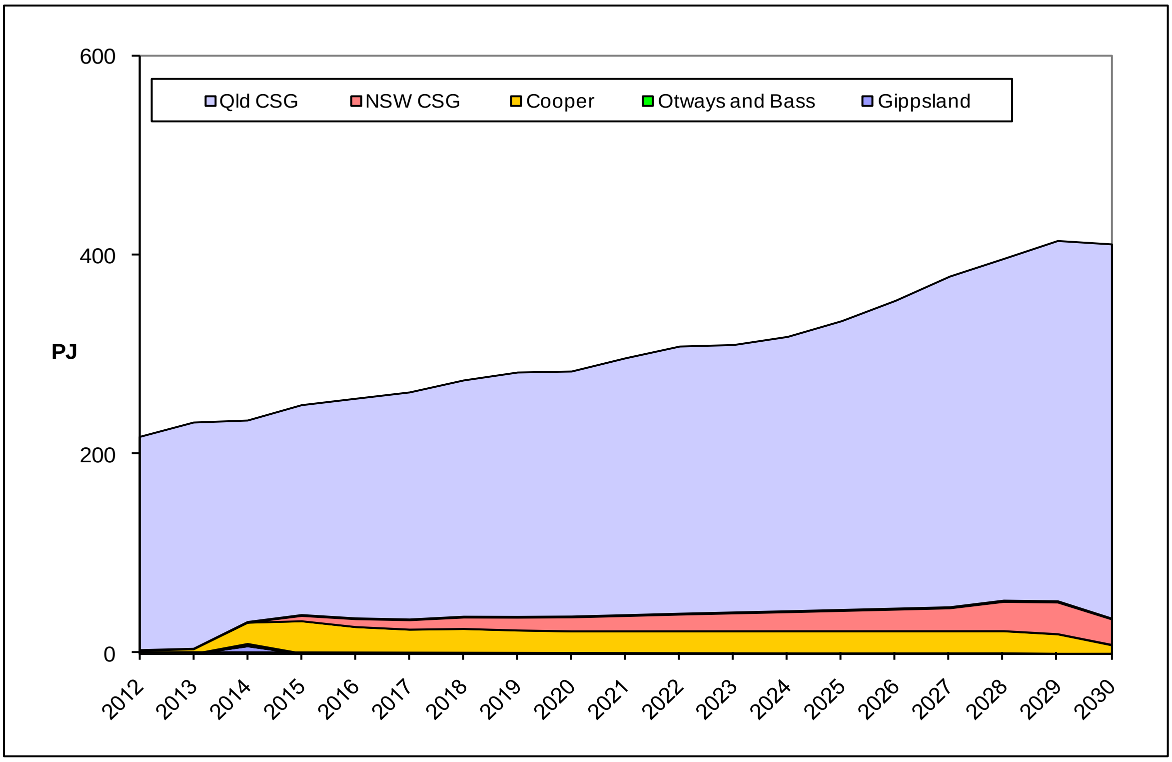
- **Figure 8-8 Projected gas supply, Queensland domestic only, High scenario (PJ)**



- **Figure 8-9 Projected gas supply, Queensland domestic only, Medium scenario (PJ)**



- **Figure 8-10 Projected gas supply, Queensland domestic only, Low scenario (PJ)**



8.3. Domestic gas price projections

Gas price projections for all three scenarios are presented in Figure 8-11 to Figure 8-24. All prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real $2011 terms. Two prices are presented for the Southern States in aggregate, for Queensland in aggregate and for each market zone in Queensland:

- The estimated price of new gas contracts starting in a particular year (Figure 8-11 to Figure 8-17). It is noted that underlying assumptions include negotiation four years in advance, so that the price for 2014 is negotiated in 2010.
- The estimated average price over all gas contracts delivering gas in any year (Figure 8-18 to Figure 8-24)

The new contract prices do not take into account the possible availability of lower priced "Ramp-Up Gas" in the period 2011-2013, because the term of availability is incompatible with other contracts. However some Ramp-up-gas is included in initial contracts and is reflected in the declining average price in Queensland up to 2014.

In each scenario the prices reflect the market balance between:

- The level of competition to supply domestic gas (lower in the High Scenario)
- The attractiveness of export prices (higher in the High Scenario)
- The cost of gas production and transmission (higher in the High Scenario because of longer transmission routes)

Prices in all Queensland zones are projected to be very sensitive to the scenarios and are broadly correlated with one another. Across Queensland in aggregate:

- In the High Scenario (with high domestic demand, high exports and high oil prices) new contract prices are expected to rise substantially from 2013, to over $8/GJ in most zones. This level is maintained until growth in LNG stops in the mid-2020s, at which point prices temporarily fall by $1-2/GJ but then rise back to former levels owing to reserve depletion.
- In the Medium Scenario (with medium domestic demand, medium exports and medium oil prices) new contract prices are expected to rise initially to approximately $6/GJ but then ease to $5/GJ as reserves growth outpaces growth in exports after 2018.
- In the Low Scenario (with low domestic demand, low exports and low oil prices) new contract prices are expected to rise slightly up to 2016 but otherwise to be more restrained.

It should be noted that these prices are derived using a model that can only be tested using historical contract prices, which are low. Actual outcomes can be expected to vary, particularly in the High Scenario, where relative market illiquidity would make it difficult for participants to "find" a new price level.

In terms of which price scenario eventuates it is important to note that prices are based on expectations regarding the future and that it appears that current market behaviour appears more reflective of the expectation of the High Scenario eventuating. This behaviour can continue for some time after it becomes evident that an alternative scenario is more likely so it is possible for prices to follow the High Scenario for several years even though the Medium Scenario eventuates.

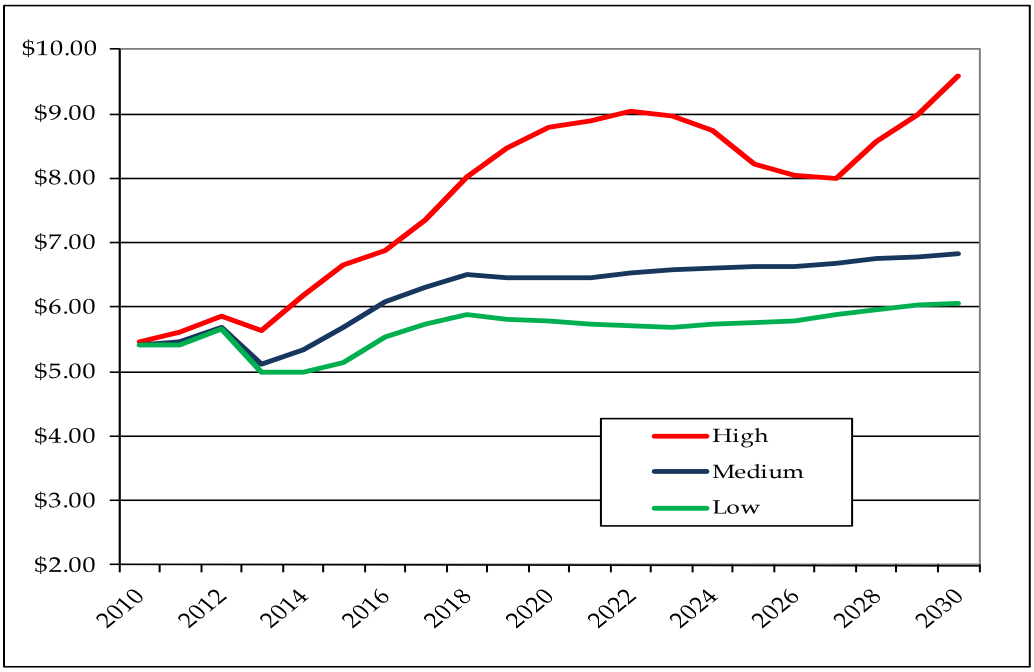
The price rises in the High Scenario are higher than in the High Scenario in the 2010 GMR, largely because of the higher LNG projections. The price rises in the Medium and Low scenario are very similar to those in equivalent scenarios in the 2010 GMR.

The trends in the Brisbane, Townsville, Gladstone and Kogan zones are similar though with different levels. The Kogan zone prices are equivalent to well-head prices for CSG produced in the Kogan-Roma/Wallumbilla area.

New contract prices in Southern States are projected to rise slightly later than Queensland prices. Some of this delay is due to the more limited requirement for new contracts, especially in Victoria.

Average contract prices follow the paths set by new contract prices but with considerable lags, which also vary between zones because of differences in timing in the need for new contracts. The more unusual average price movements, such the jumps in Brisbane and Mt Isa prices towards the end of the period, are due to large price differential between new contracts and the ones they replace.

- **Figure 8-11 New contract prices Southern States aggregate, all scenarios ($/GJ, $2011 real)**



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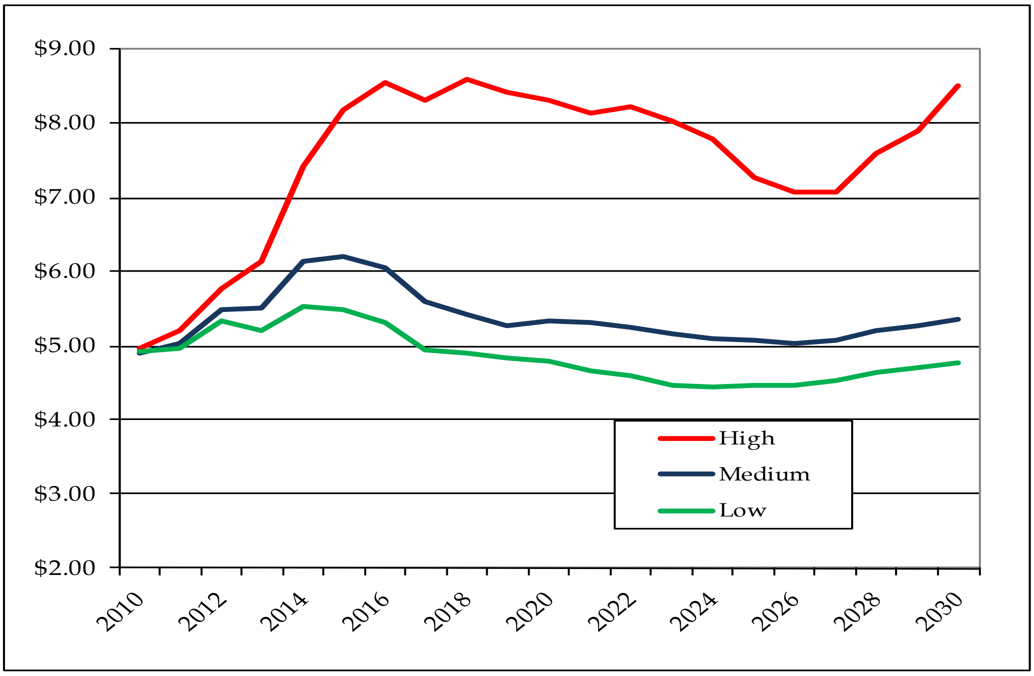
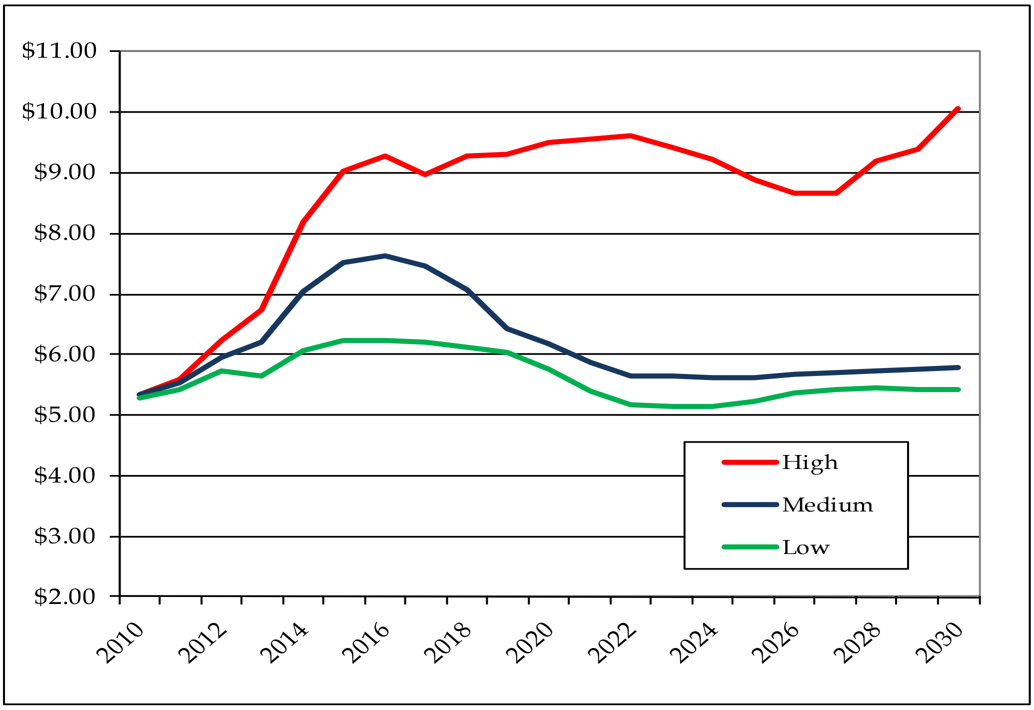
- **Figure 8-12 New contract prices Queensland aggregate, all scenarios ($/GJ, $2011 real)**

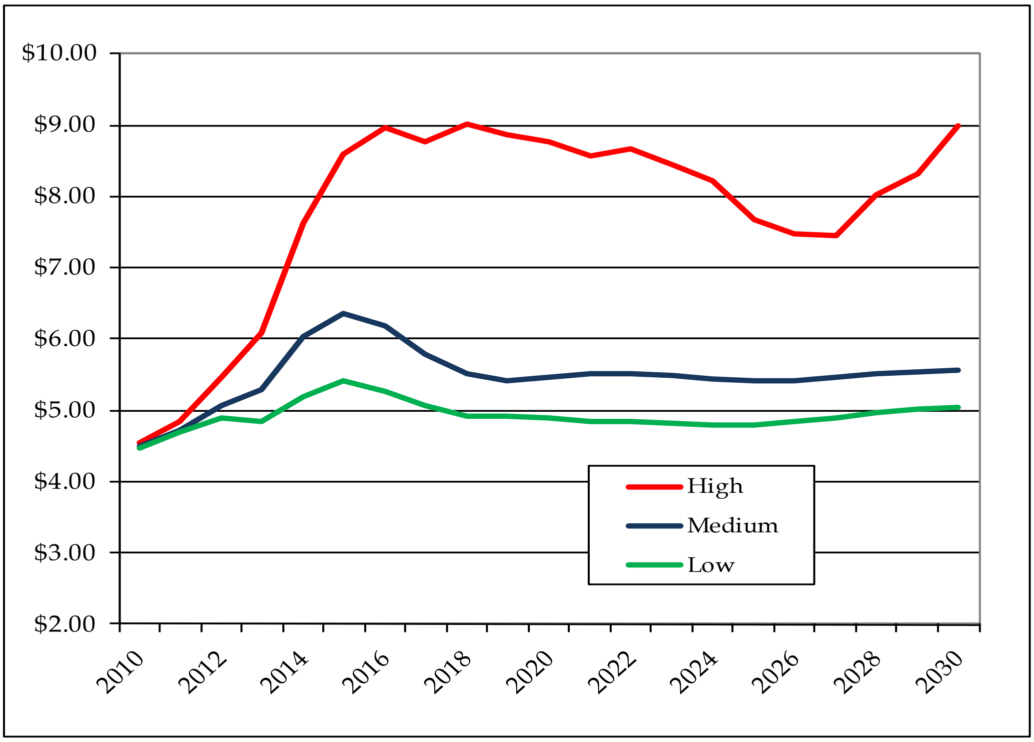


- **Figure 8-13 New contract prices Brisbane zone, all scenarios ($/GJ, $2011 real)**

■ **Figure 8-14 New contract prices, Townsville zone, all scenarios ($/GJ, $2011 real)**

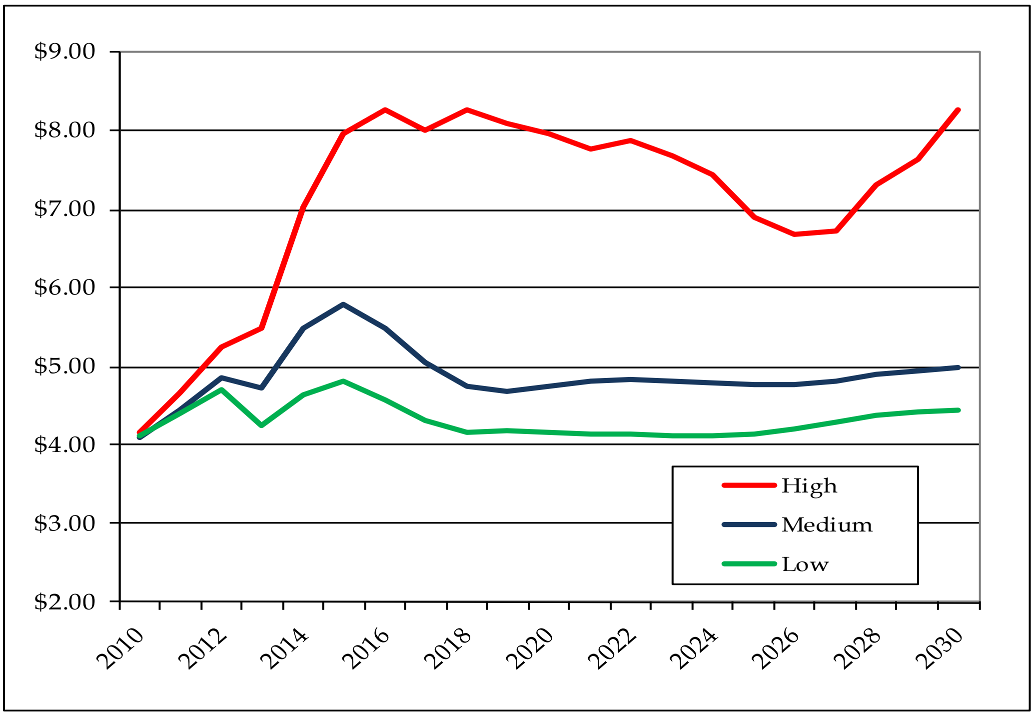


■ **Figure 8-15 New contract prices Gladstone zone, all scenarios ($/GJ, $2011 real)**

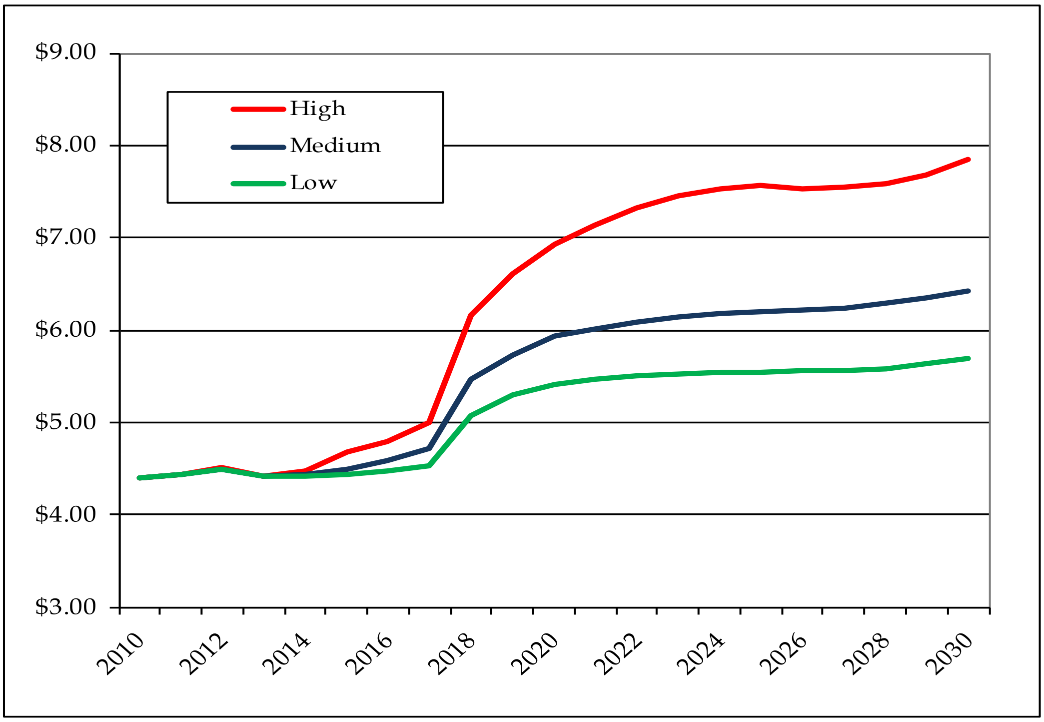


- **Figure 8-16 New contract prices Mt Isa zone, all scenarios ($/GJ, $2011 real)**

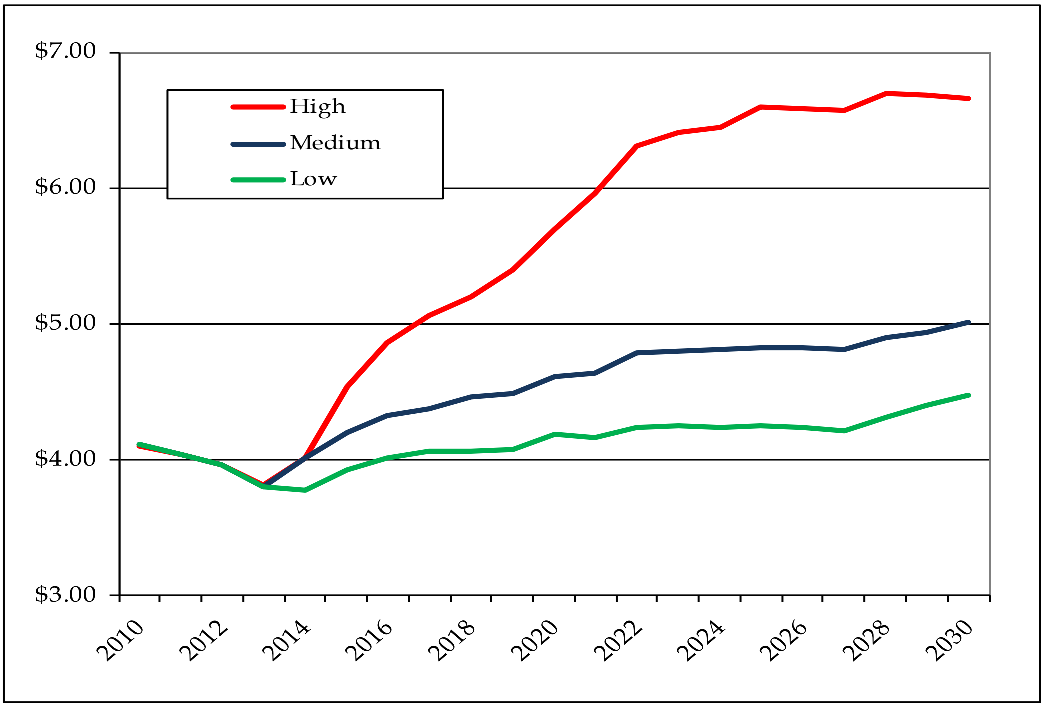
- **Figure 8-17 New contract prices Kogan zone, all scenarios ($/GJ, $2011 real)**



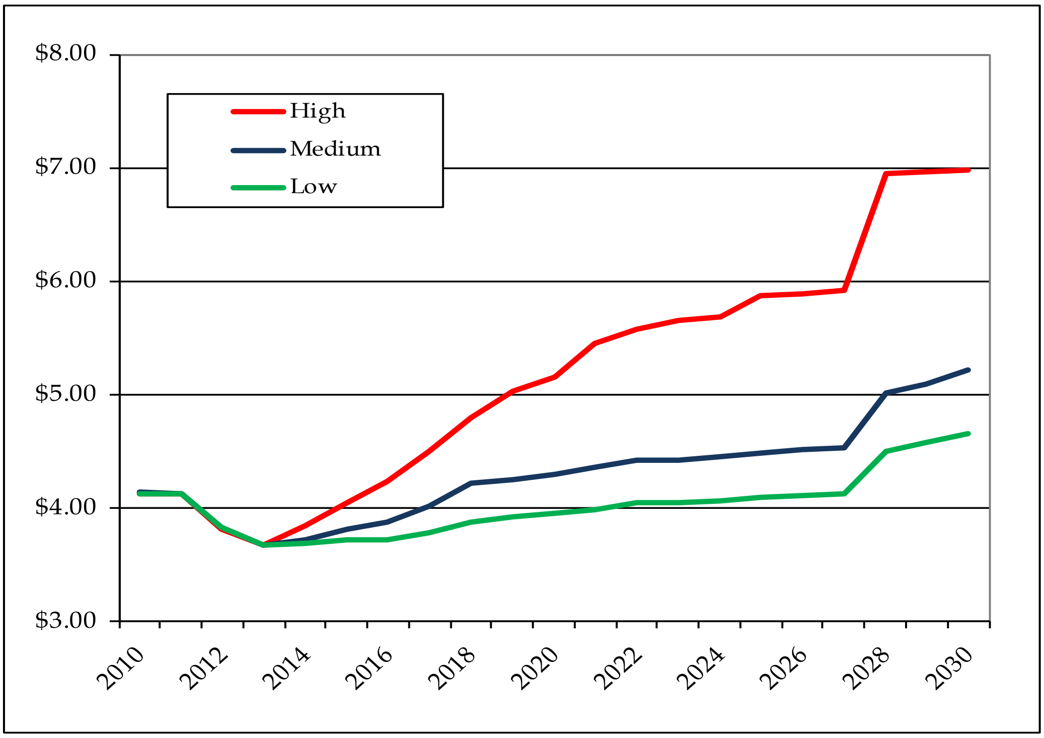
- **Figure 8-18 Average contract prices Southern States aggregate, all scenarios ($/GJ, $2011 real)**



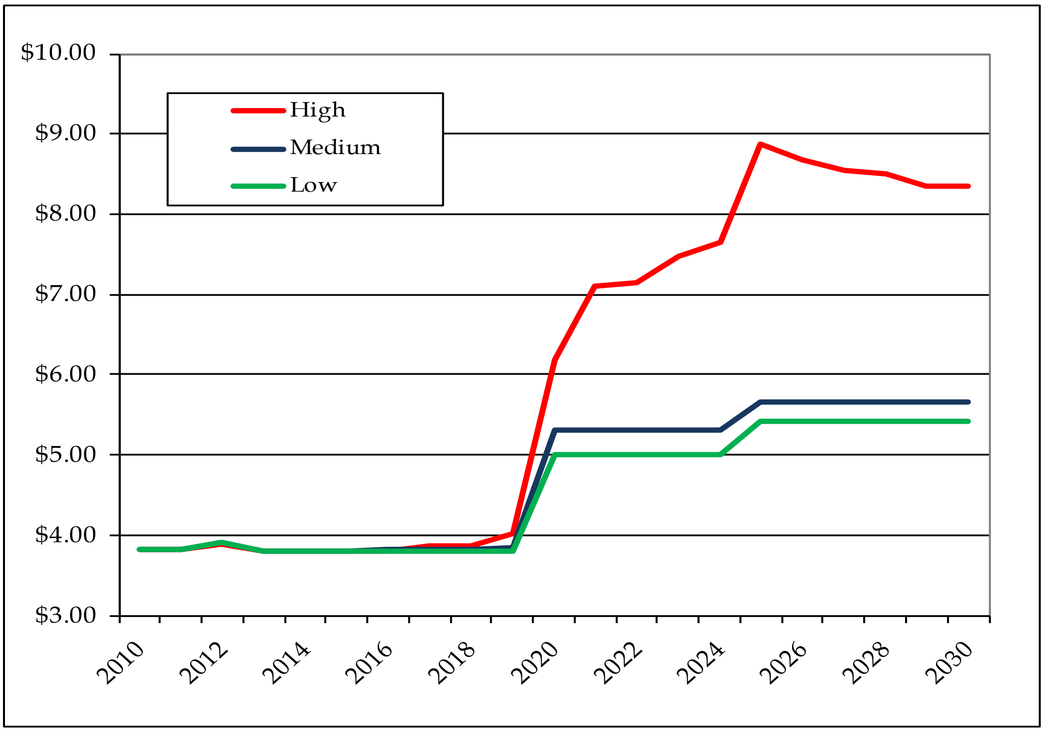
- **Figure 8-19 Average contract prices Queensland aggregate, all scenarios ($/GJ, $2011 real)**



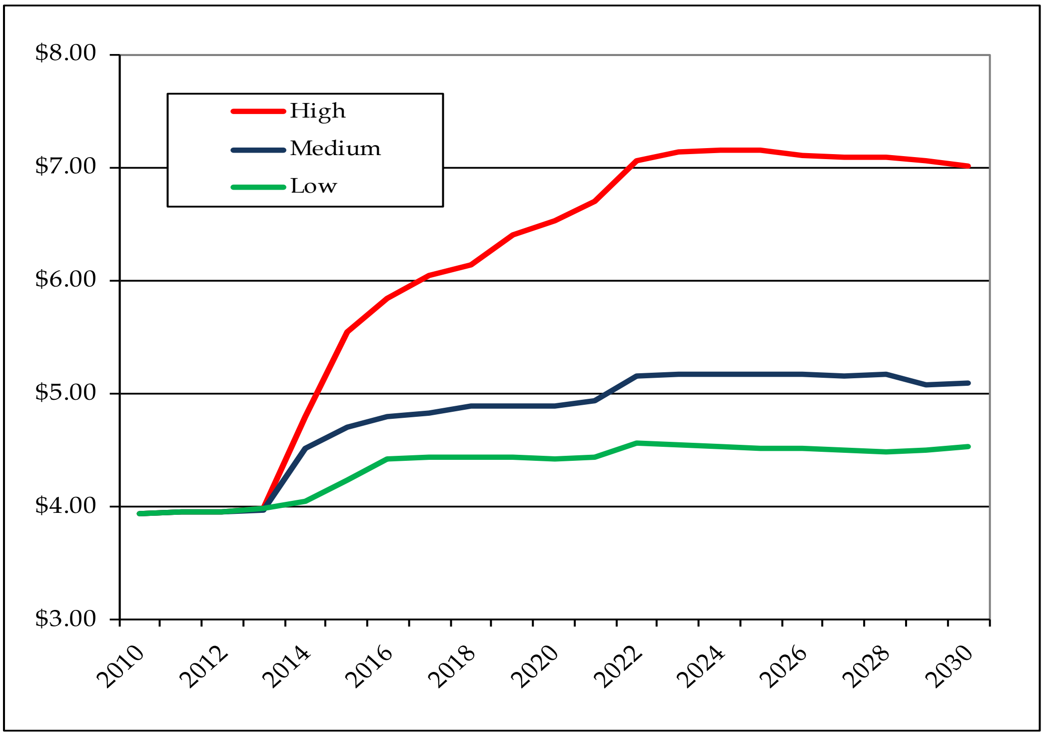
- **Figure 8-20 Average contract prices Brisbane zone, all scenarios ($/GJ, $2011 real)**



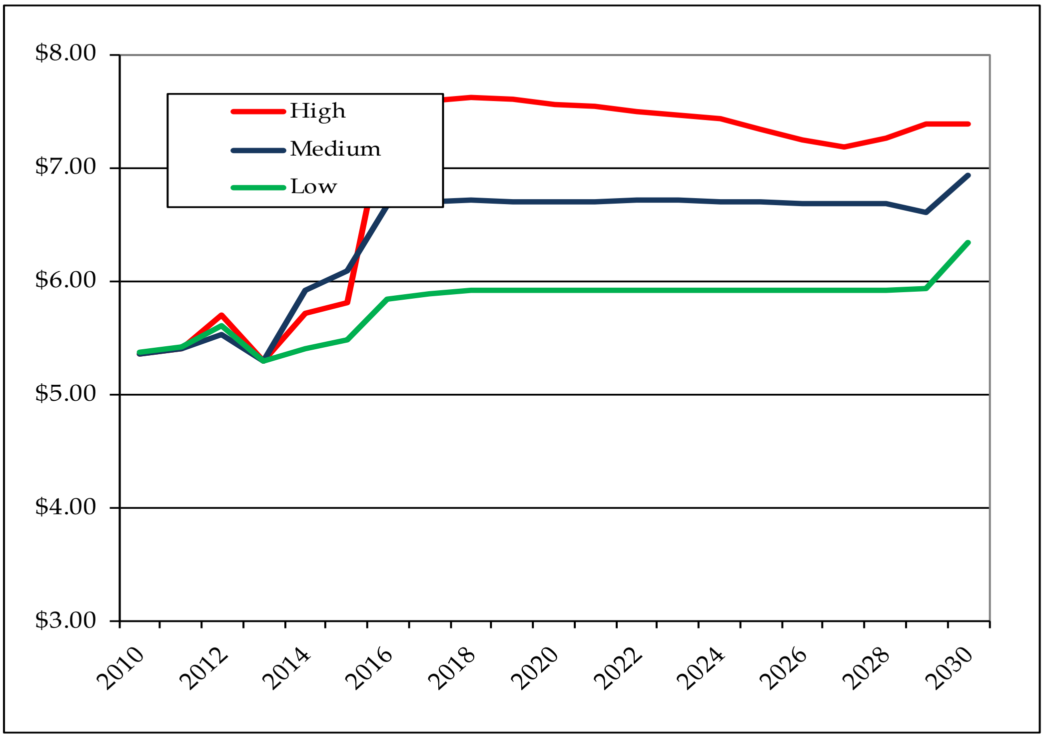
- **Figure 8-21 Average contract prices, Townsville, all scenarios ($/GJ, $2011 real)**



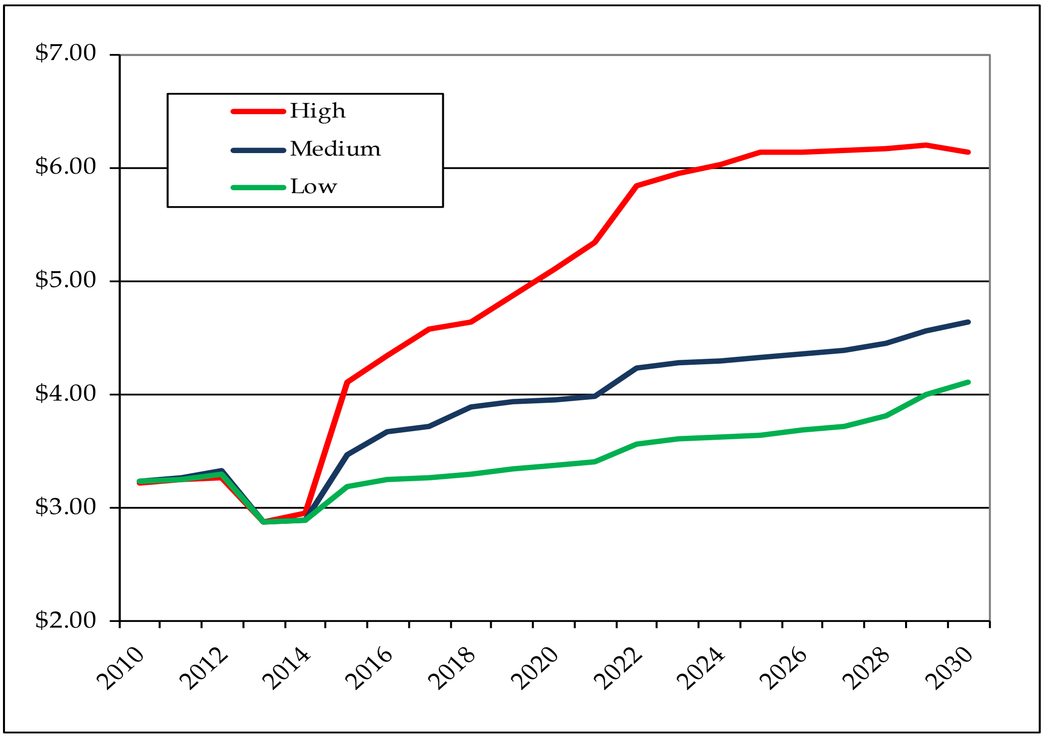
- **Figure 8-22 Average contract prices Gladstone zone, all scenarios ($/GJ, $2011 real)**



- **Figure 8-23 Average contract prices Mt Isa zone, all scenarios ($/GJ, $2011 real)**



▪ **Figure 8-24 Average contract prices Kogan zone, all scenarios ($/GJ, $2011 real)**



8.4. Demand response to price increases

Differences between the prices assumed in developing demand scenarios and the price outcomes from establishing demand supply balance result in an adjustment of modelled demand. In the gas market generally and in the above modelling, the first price adjustments are to new gas contracts and over time, as new contract prices feed into averages prices, the aggregate demand is adjusted.

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 8-2), 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 8-2 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%

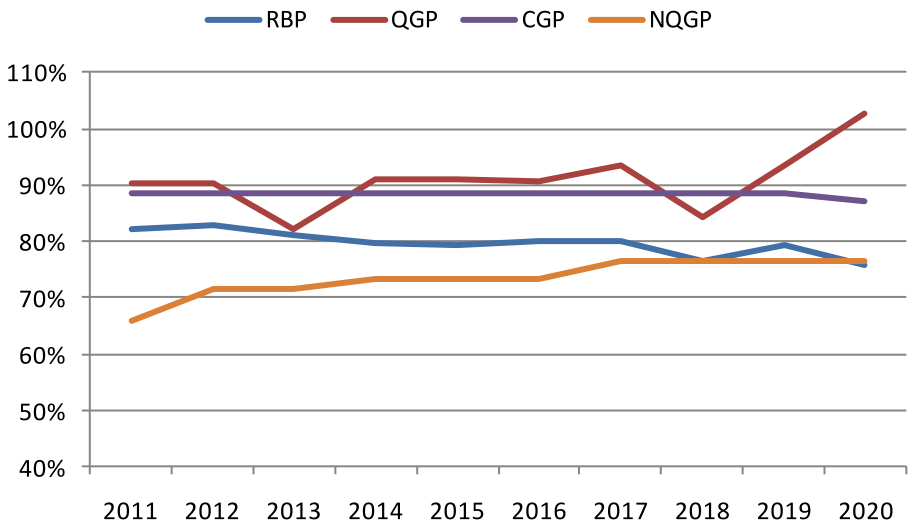
9. Transmission capacity

9.1. Peak demand-supply

Peak demand in all Queensland sub-markets is currently met by pipeline gas, without any material support from LNG or underground storage[34]. Analysis of GSOO 2010 peak and annual demand projections suggests that each of the four major pipelines will face approximately static load factors (ratio of average daily load to peak daily load) over the next ten years (Figure 9-1). This means that pipeline expansion in proportion to annual demand, in line with current load factors, will be sufficient to meet peak domestic market requirements over the next ten years.

It is noted that underground storage is likely to form part of demand-supply management for LNG projects but this is unlikely to impact on the capacity requirements for these pipelines.

- **Figure 9-1 Queensland gas pipeline load factors based on 1-in-2 peak demand**



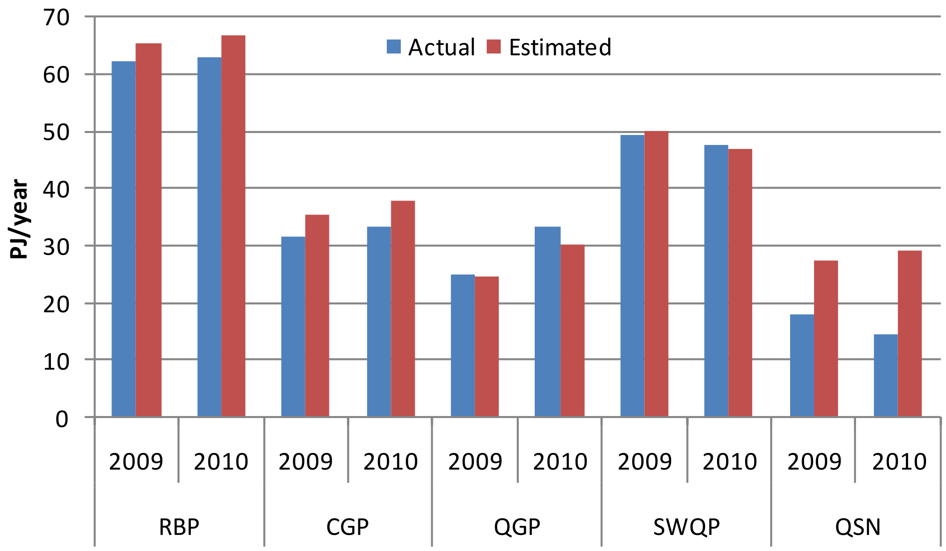
[34] The small Newstead Gas storage operated by Origin Energy is understood to be used solely to support Origin's power generation plants.

9.2. Transmission pipeline capacity requirements

Transmission capacity constraints are not explicitly modelled in MMAGas. Instead it is assumed that new transmission capacity will be added in parallel with gas production/processing capacity when required, at the costs built into the model. This assumes that the increments required are ultimately economic, i.e. annual increments add up to an economic increment over time.

Figure 9-2 shows the model output of annual throughput volume of the major pipelines under each scenario for calendar years 2009 and 2010, as well as the actual flow quantity on those pipelines sourced from the Gas Bulletin Board. With the exception of QSN, the model accurately replicates actual flows.

- **Figure 9-2 Actual and estimated throughput of major Queensland pipelines – Bulletin Board & MMAGas (PJ)**



For the purpose of addressing peak demand issues and pipeline capacity constraints, peak demand forecasts have been estimated from annual volume throughput (forward or back haul as appropriate) obtained from MMAGas.

9.2.1. Approach

MMAGas is a model that operates on an annual volume basis. In order to estimate capacity constraints on pipelines, the annual throughput volume output (PJ) needs to be converted to estimates of peak demand (TJ/day). The peak demand estimates are then compared to the notional capacity on each pipeline to determine where capacity constraints could arise in meeting gas demand during the period.

In estimating peak demand, a three step approach has been adopted:

1. Peak demand on each pipeline is estimated using a pipeline specific historical load factor sourced from the Bulletin Board and grouped to estimate Zone peak;
2. A second Zone peak demand is estimated using the Zone historical load factor sourced from the Bulletin Board;
3. The pipelines' peak demand from step 1are then scaled to match the two Zone estimates.

In case of pipelines not yet built or those not in the Bulletin Board, SKMMMA has estimated the peak demand on that particular pipeline assuming a load factor of 80%.

Nominal capacities of the major pipelines were sourced from the Gas Bulletin Board. In case of pipelines not yet built or those not in the Bulletin Board, SKMMMA has searched the public domain (e.g. EIS) to obtain an estimate. It is noted that nominal capacities can be conservative in the sense that they may apply to firm contract capacity, which can be exceeded for short but not prolonged periods.

Capacity requirements are estimated on the basis of total market requirements. It is assumed that capacity is efficiently allocated to market participants, i.e. that participants do not reserve capacity they do not use and thereby prevent others from gaining access to it.

9.2.2. Projections

9.2.2.1. South West Queensland Pipeline (SWQP)

Figure 9-3 shows the projections of peak demand and capacity for SWQP.

The High scenario produces the lowest projections initially until around 2023 owing to the relative lack of Queensland CSG available for export to the Southern states. After this time, the number of

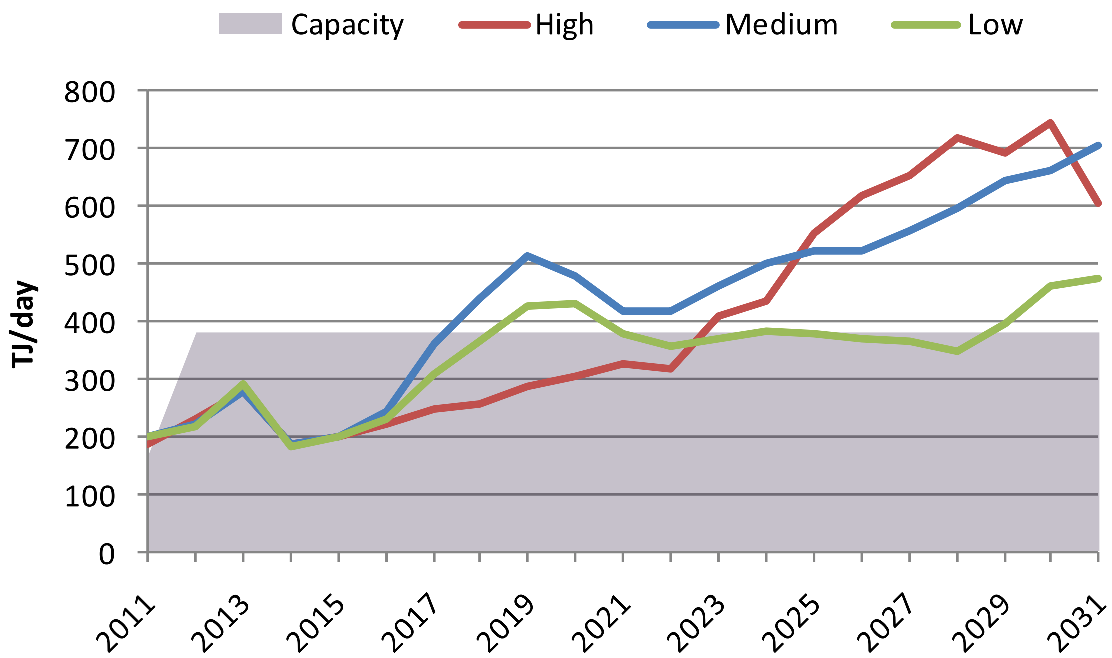
LNG projects stops at 17 trains leading to a substantial amount of developing reserves becoming available to the domestic market. Much of this gas is exported to the Southern states.

Under the Medium and Low scenarios, there are increased flows along the SWQP for the period 2017 to 2020. This is mainly caused by the rapid reserve development required for export from committed trains to 2016 (two per year), after which time the rate of train start-up falls off causing the release of more Queensland CSG to the domestic market.

The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2023 and peaking in 2030 at roughly 365 extra TJ/d.
- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2018 and peaking initially in 2020 at roughly 100 extra TJ/d. Another increase in flow leading to additional capacity requirement is expected from around 2024 to peak at the end of the period at roughly 326 extra TJ/d.
- In the Low scenario, except for 2019 and 2020, the SWQP is estimated to be at capacity for the period to 2030. Additional capacity of around 100 TJ/day would be required after 2030. For the years 2019 and 2020, around 50 TJ/day of extra capacity is required, however there is a possibility that this does not lead to an expansion owing to the short term nature of the requirement.

▪ **Figure 9-3 Estimated peak flow and capacity - SWQP (TJ/day)**



9.2.2.2. QSN Link

Figure 9-4 shows the projections of peak demand and capacity for QSN.

The peak demand estimates for QSN are similar to that of the SWQP because most of the gas flowing through the SWQP is ultimately exported to the Southern states through the QSN.

The QSN (and the SWQP) is already scheduled for a capacity expansion that is targeted to be available from January 2012. QSN expansion requirements largely parallel those of the SWQP.

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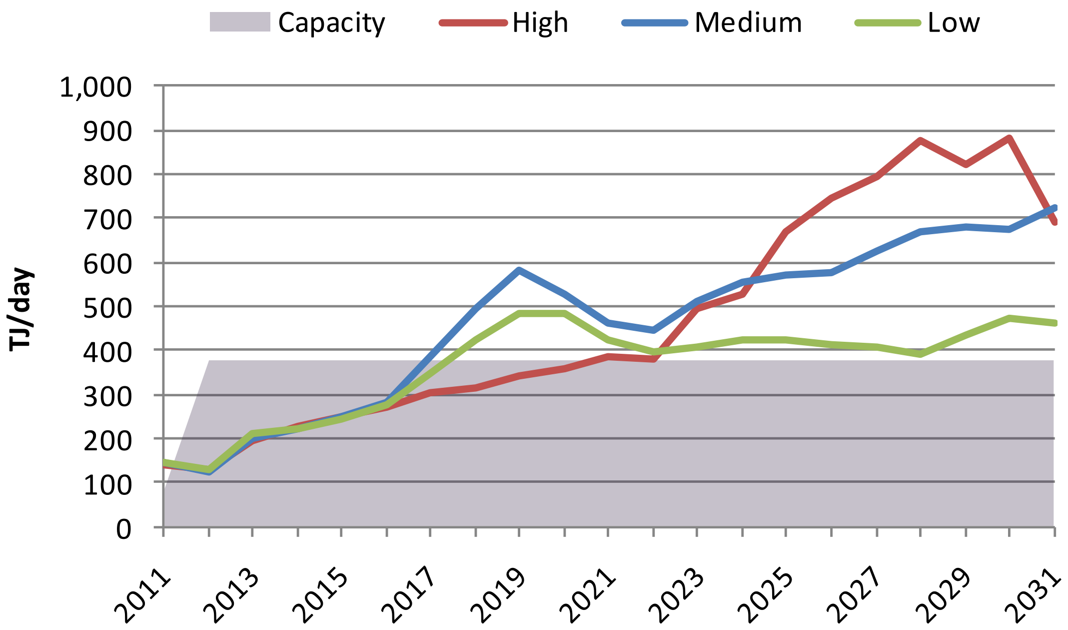
▪ **Figure 9-4 Estimated peak flow and capacity - QSN (TJ/day)**



9.2.2.3. Roma to Brisbane Pipeline (RBP)

Figure 9-5 shows the projections of peak demand and capacity for RBP.

This pipeline is already at full capacity and low capacity expansion is under construction. In all scenarios MMAGas projects that Clarence Morton basin gas will meet some Brisbane demand growth via the Lions Way pipeline, with the result that RBP peak flows do not grow at the same rates as the zone demand forecasts shown in Figure 4-19 . In the Medium and High scenarios it is projected that some Clarence Morton Basin gas will be sold to LNG projects in Gladstone – this gas is assumed to be backhauled on the RBP from Brisbane to Wallumbilla without any capacity requirements.

The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity may be required in the short-term, starting now and peaking in 2017 at roughly 35 extra TJ/d. Peak demand is then projected to remain below capacity throughout the rest of the period.
- In the Medium and Low scenarios peak demand declines from its 2011 value and remains below capacity throughout the rest of the period.

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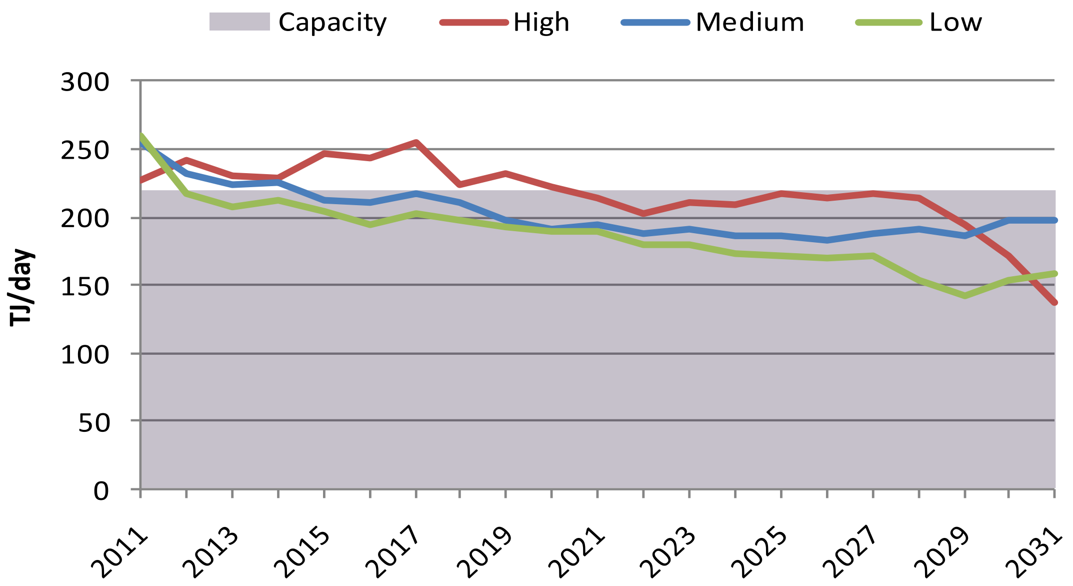
▪ **Figure 9-5 Estimated peak flow and capacity - RBP (TJ/day)**

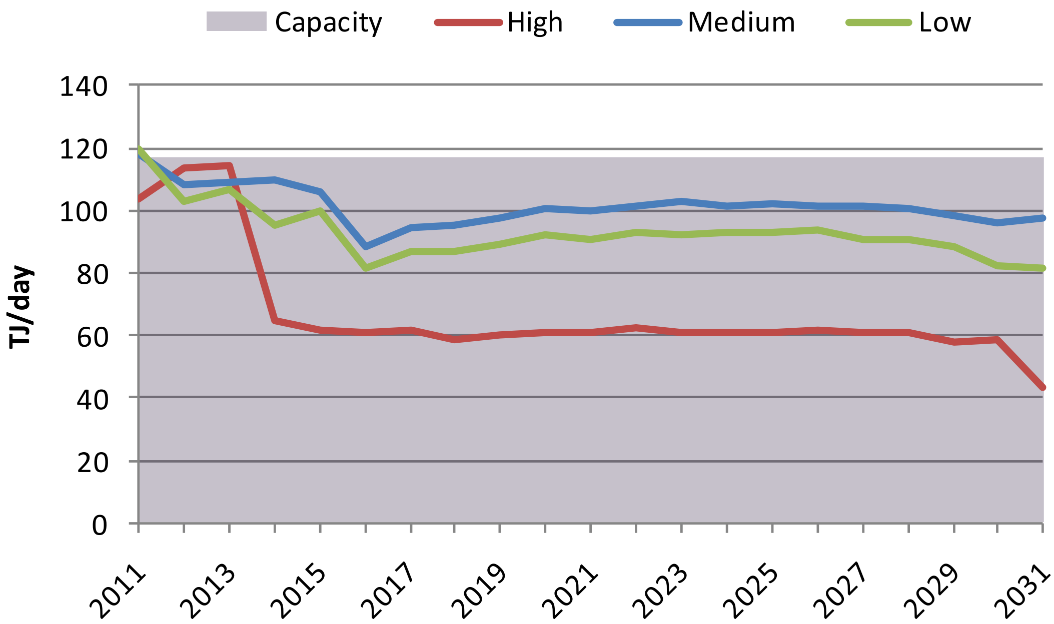


9.2.2.4. Carpentaria Gas Pipeline (CGP)

Figure 9-6 shows the projections of peak demand and capacity for CGP. These projections directly reflect the gas demand projections shown in Figure 4-21 apart from variations due to price adjustments.

No additional capacity is required in any of the three scenarios. In the High scenario the load in Mt Isa is projected to fall owing to connection of Mt Isa to the electricity transmission network.

▪ **Figure 9-6 Estimated peak flow and capacity – CGP (TJ/day)**



9.2.2.5. Queensland Gas Pipeline (QGP)

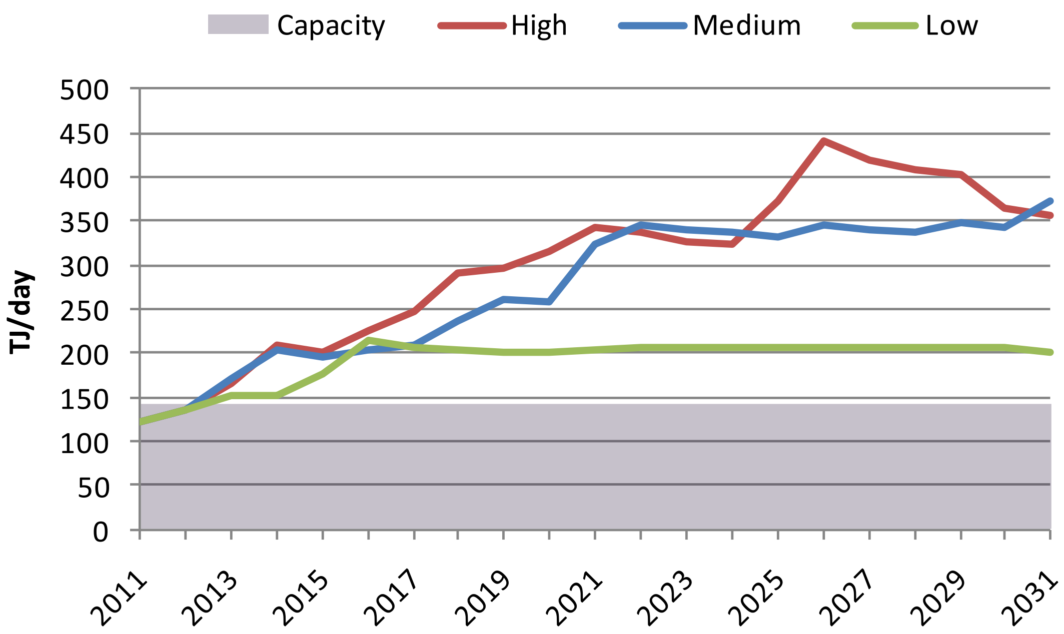
Figure 9-7 shows the projections of peak demand and capacity for QGP. The peak demands in each scenario broadly follow the trends in the demand projections (Figure 4-20). In the High Scenario some Gladstone demand is met by gas from the Moranbah production centre transported via the Moranbah-Gladstone pipeline. Some of the incremental capacity requirements after 2014 could be substituted by LNG project pipelines.

The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required at an increasing rate, starting in 2012 and peaking initially in 2021 at roughly 100 extra TJ/d. Around 2026, there is a marked increase in the estimate of peak demand and reached highest level in 2027 of another additional 100 TJ/d before decreasing towards the 2021 level by the end of the period. This is likely to be caused by a similar increase seen in SWQP when the number of LNG project stops at 17 trains which releases the prior reserves development to the domestic market.

- In the Medium scenario, additional capacity would be required at an increasing rate, starting in 2012 and peaking in 2022 at roughly 200 extra TJ/d. The peak demand is then estimated to be stable until around 2031 when it can be seen to increase again.
- In the Low scenario, additional capacity would be required at an increasing rate, starting in 2013 and peaking in 2016 at roughly 75 extra TJ/d. The peak demand is then estimated to be stable throughout the rest of the forecasting period.

Figure 9-7 Estimated peak flow and capacity – QGP (TJ/day)



9.2.2.6. North Queensland Gas Pipeline (NQGP)

Figure 9-8 shows the projections of peak demand and capacity for NQGP. These projections directly reflect the gas demand projections shown in Figure 4-23 apart from variations due to price adjustments.

The determined capacity constraints for each of the three scenarios are summarised in the following:

- In the High scenario, additional capacity would be required from 2023 and increasing throughout the rest of the period to around 30 extra TJ/d.

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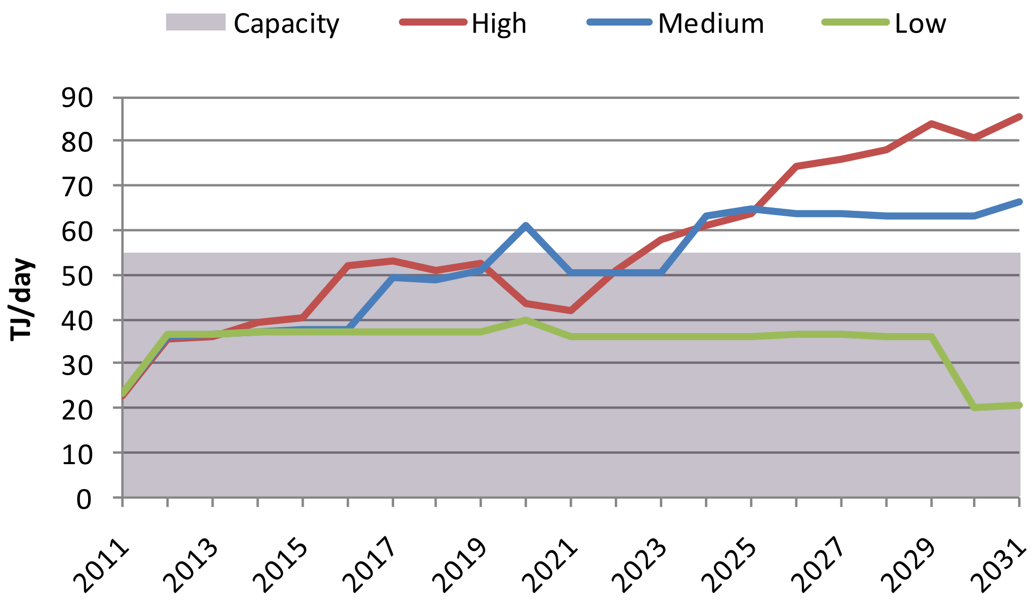
- In the Medium scenario, ignoring the one year peak demand spike in 2020, first required expansion would be around 2024 of around 10TJ/d until the end of the period.
- In the Low scenario, no additional capacity is required.

Figure 9-8 Estimated peak flow and capacity - NQGP (TJ/day)



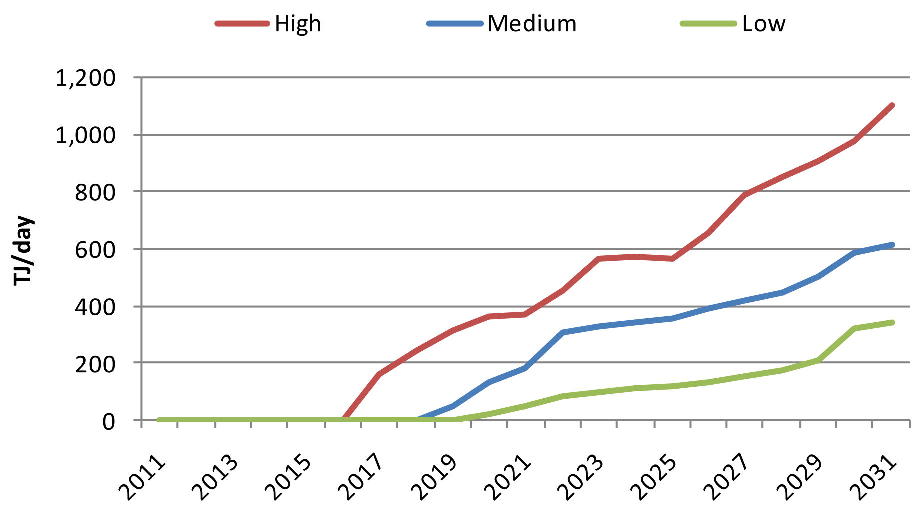
9.2.2.7. Moranbah to Gladstone Pipeline

Figure 9-9 shows the projections of peak demand and capacity for Moranbah to Gladstone Pipeline. Most demand is for the LNG projects at Gladstone – only in the High Scenario does Moranbah gas also supply the Gladstone domestic market. Pipeline capacity will be designed to meet LNG requirements and is not shown in Figure 9-9.

- In the High Scenario peak demand is estimated to start at 160 TJ/d in 2017 and grow rapidly throughout the period to around 1,100 TJ/d. The required capacity would need to start at up to 600 TJ/d and to be doubled after 2023 by adding compressors or looping.
- In the Medium Scenario peak demand is estimated to start at 130 TJ/d in 2020 and grow rapidly throughout the period to around 600 TJ/d. The required capacity would need to start at up to 400 TJ/d and to be increased after 2025 by adding compressors or looping.

- In the Low scenario, peak demand is estimated to start at 50 TJ/d in 2021 and grow throughout the period to around 400 TJ/d. The required capacity would need to start at up to 200 TJ/d and to be increased after 2029 by adding compressors or looping.

Figure 9-9 Estimated peak flow and capacity – Moranbah to Gladstone Pipeline (TJ/day)



9.2.2.8. LNG Pipelines

The analysis done here is for the combined total of all LNG export pipelines. Figure 9-10 shows the projected peak demand under each of scenarios.

The estimated peak flow is very similar under all scenarios for the period to 2016 reflecting the requirement of the current committed trains. From 2017 onwards, the peak flow estimates are as follows:

- In the High scenario, LNG export continues growing rapidly and peaks in 2027 at around 9,000 TJ/d before decreasing slightly.
- In the Medium scenario, LNG export increases steadily to peak in 2026 at around 5,400 TJ/d and stabilise throughout the rest of the period.
- In the Low scenario, LNG export stops growing and stabilises to a very slight decrease throughout the rest of the period.

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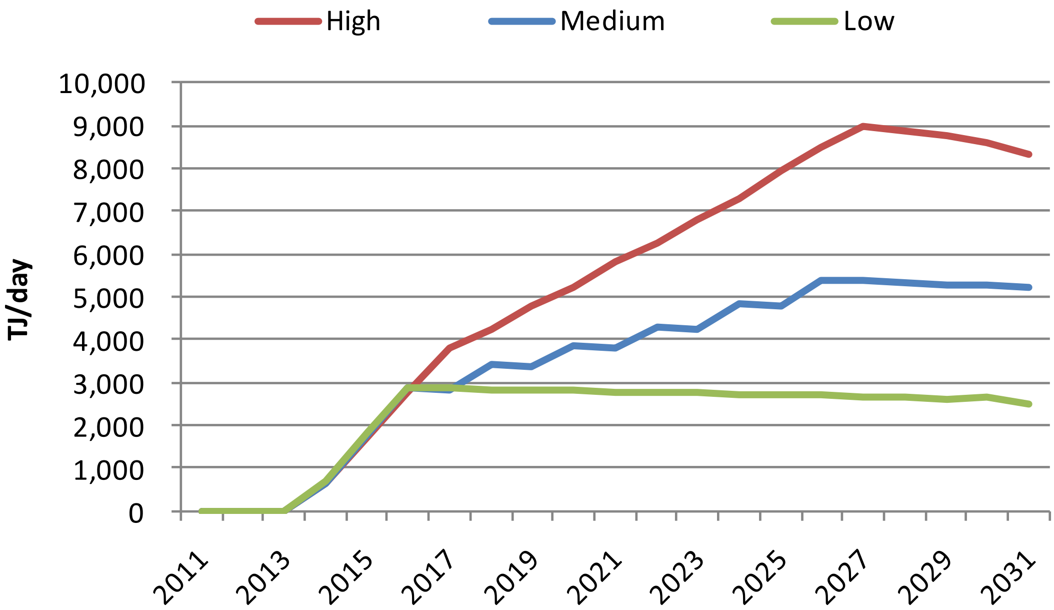
▪ **Figure 9-10 Estimated peak flow – Combined LNG export pipelines (TJ/day)**



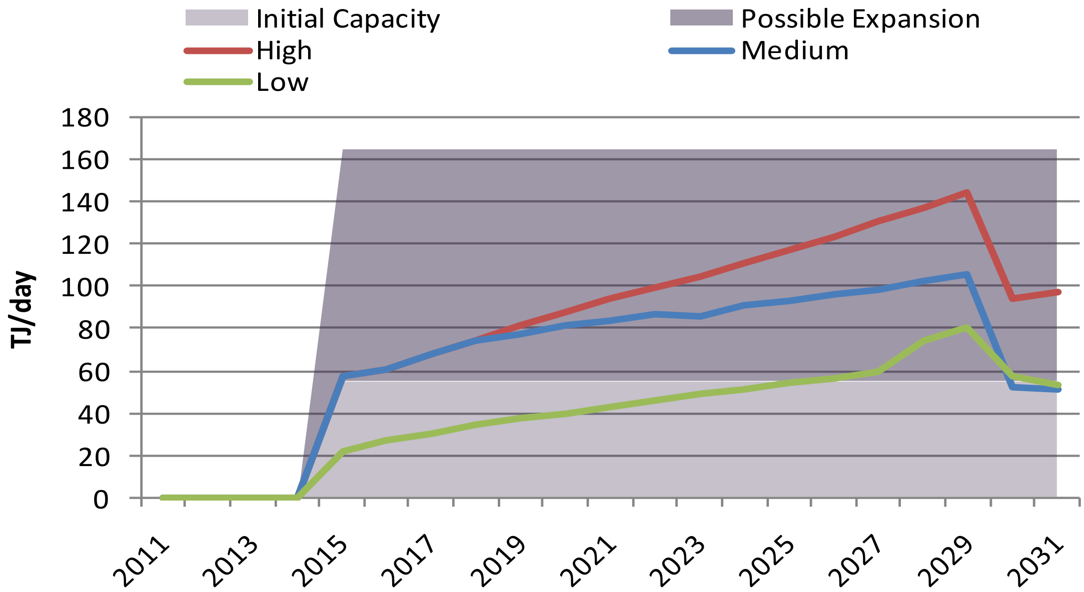
9.2.2.9. Lions Way Pipeline

Figure 9-11 shows the projections of peak demand and capacity for the Lions Way Pipeline. In the Medium and High scenarios gas is transported for LNG projects (via backhaul on RBP to Wallumbilla) as well as for the Brisbane domestic market.

The capacity was obtained from a preliminary Environmental Impact Statement, which lists the capacity of this pipeline to be between 20 to 60 PJ per annum depending on demand. However this is clearly inadequate if there are shipments to LNG projects. The pipeline is assumed to be operational by 2015.

- In the High scenario, initial capacity of 20 PJ/annum is enough to for the first year. Peak demand is then estimated to continue increasing to peak at around 145 TJ/d in 2030. The required capacity at this stage would be around 55 PJ/annum.
- In the Medium scenario, initial capacity of 20 PJ/annum is enough to for the first year. Peak demand is then estimated to continue increasing to peak at around 100 TJ/d in 2030. The required capacity at this stage would be around 40 PJ/annum.
- In the Low scenario, initial capacity of 20 PJ/annum would be sufficient until 2025. For the period 2026 to 2029 there seems to be a short term increase in peak flow estimate before returning to 2025 level by the end of the period.

■ **Figure 9-11 Estimated peak flow and capacity – LWP (TJ/day)**



APPENDIX A MMAGAS

A.1 Key gas market modelling issues

The Australian wholesale gas market presents significant challenges to analysts seeking an understanding of its future evolution:

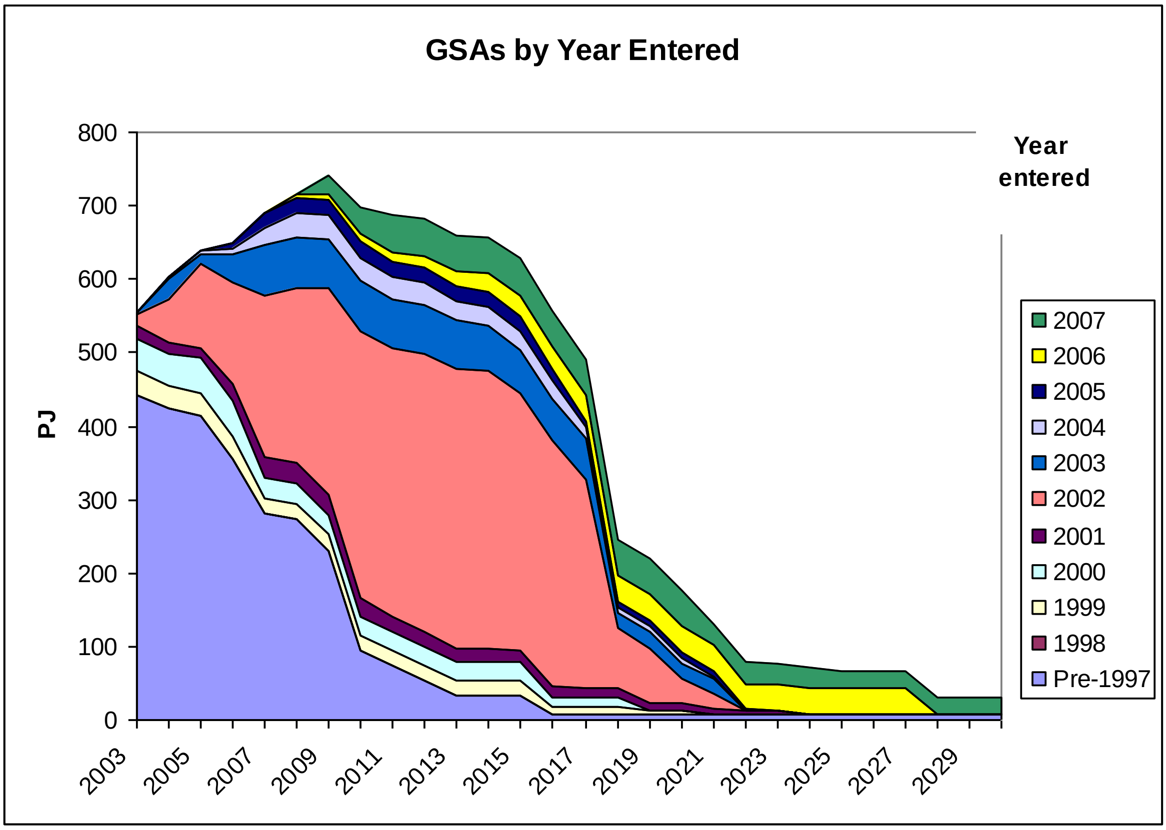
- The market structure is evolving and many relationships are determined by participants rather than under formal market rules. Consequently the nature of the structure is not a given.
- Information on market transactions is held in confidence. Outline information is provided for ASX purposes but details are lacking.
- Public domain gas production cost information is very limited.
- Gas demand forecasts are available only at the state level.

A.2 Market developments

The Australian gas market entered the competitive era in November 1997 with the signing of the Gas Pipelines Access Agreement and the promulgation of the National Third Party Access Code for Natural Gas Pipeline Systems. Under the Agreement and the Code, third parties have gained access to the natural gas delivery system and downstream market franchises have been progressively opened to competition.

No changes were legislated in the upstream, gas production, sector and initially the legacy gas supply agreements (GSAs) dating from the pre-competitive era continued to provide the majority of gas supply and to set the benchmarks for wholesale gas prices. Anticipating a decline in dedications from some of these agreements, a significant number of new GSAs have been reached, particularly since 2002, as illustrated in Figure A- 1.

▪ **Figure A- 1 Current Gas Sales Agreements, Eastern Australia**



Prior to 2002, the concentration of ownership of gas reserves and production facilities resulting from the monopoly era gave rise to considerable uncertainty regarding the prices that would apply in new GSAs. In the short term however incumbents' market power has been limited by new entrants and the new agreements for supply to the southern states have been reached at headline prices[35] similar to those in legacy agreements covering supply from the Gippsland and Cooper Basins. New agreements for supply in Queensland have resulted in delivered prices below those in the Cooper Basin contracts dating from the mid 1990s. Many of the new entrants are developing gas supply in essentially new provinces, such as the offshore Otway basin and Queensland coal seam gas, from resources that have been discovered since 1997 due to the stimulus of market access.

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[35] The term "headline prices" refers to the price of gas under a GSA in $/GJ terms and does not take into account the value in a GSA created by non-price factors.

Resource concentration nevertheless persists, together with the potential for market power to be exercised. Sale of gas at marginal costs, as in very competitive markets, is unlikely to occur and producers will make some additional profits above their cost of supply. These profits will depend on future levels of competition and create longer-term price uncertainty, which is a critical issue for all participants and policy makers, particularly in view of the role of gas in power generation and in reducing greenhouse emissions.

A.3 Market structure

The key transactions in the gas wholesale market are the long-term GSAs between producers and buyers such as retailers, generators and large industrials. Many recent agreements have been for a shorter term than the legacy agreements were when they were entered but the majority are for at least ten years and some are for fifteen years or more, as Figure A- 1 shows. Long-term GSAs are particularly important to new entrants, as they provide secure cash flows necessary to support investment in production capacity.

Short-term gas markets are undeveloped and illiquid in Australia at present and a recent ABARE study[36] has concluded that short-term market illiquidity will continue for the foreseeable future. In Victoria most of the gas bid into the spot market[37] is bid by buyers, sourced from long term GSAs with producers, hence the GSA prices play a significant role in determining the spot prices that apply to participants' imbalances.

These factors do not preclude the emergence of a short-term market, driven either by participants, perhaps in response to demand-supply imbalances, or by the gas market program initiated by the Ministerial Council on Energy. However they do suggest that a short-term market may be predominantly a secondary trading market, with longer-term GSAs ultimately determining gas prices.

Modelling future gas supply-demand and pricing therefore appears to be a question of modelling the formation of GSAs, as the need for further gas supply arises, or where new GSAs may displace existing GSAs. The critical question in constructing such a model is defining what is being competed for at any time:

- How far into the future?
- What volumes of gas?

The answer to the first question is given above – typically ten to fifteen years. The volume issue is more complex however. Figure A- 1 shows that much more gas was being competed for in 2002

[36] Australian Gas Markets, moving towards maturity, ABARE December 2003.

[37] The Victorian gas spot market was established in 1999 as part of a price-based gas scheduling and transmission balancing regime

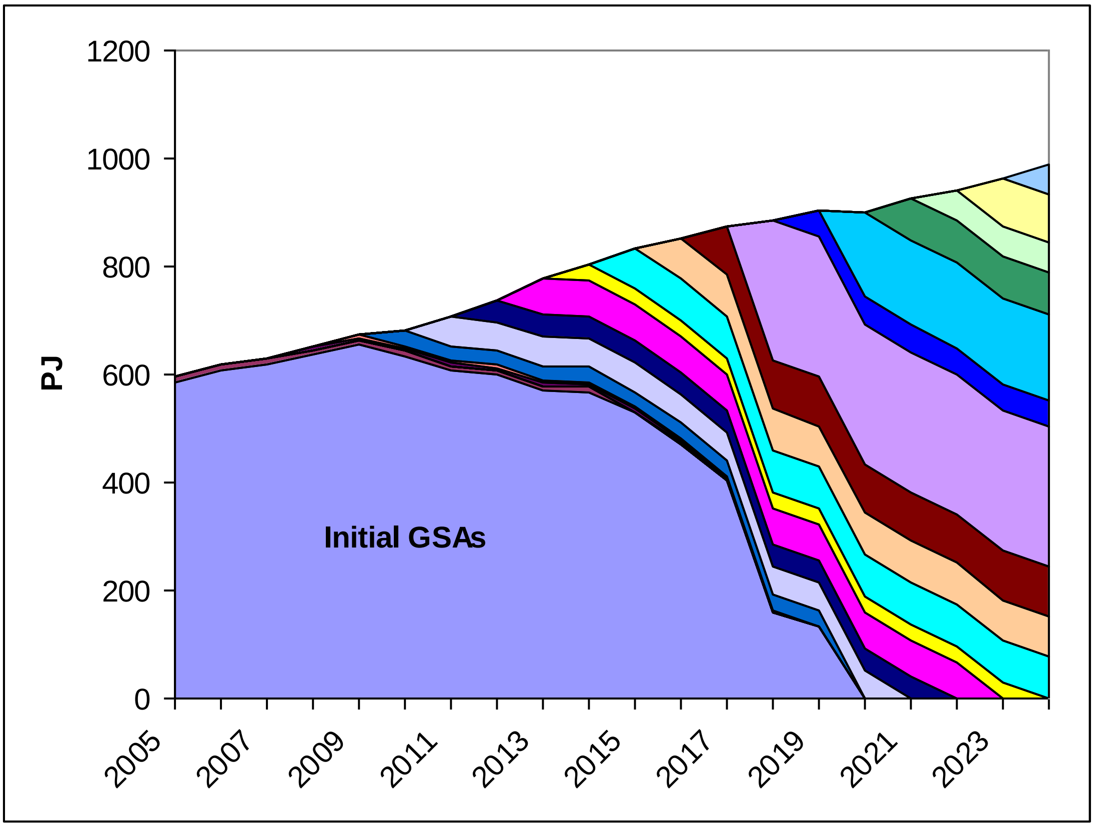
than in subsequent years, in which new GSAs appear to provide approximately one year's additional market cover.

Ideally, a model such as MMAGas would itself estimate the market structure based on the risk/reward factors considered during GSA negotiation. As a first stage in model development however the market structure is treated as an input:

- The length of new GSAs is fixed, typically at ten years, reflecting the likelihood that future terms may be shorter
- The volume competed for is based on incremental market requirements, i.e. the difference between projected demand and the then current GSAs, for a defined period, such as one, two or five years.

The market is therefore modelled as a sequence of discrete competitive events, at intervals equal to the period defining the volume being competed for. The build up of GSAs is illustrated in Figure A- 2. The competitors are all the gas producers who have uncontracted reserves that can be produced in time to meet the incremental market requirements, including both existing producers and potential new entrants.

Figure A- 2 MMAGas projected GSA build up



By implication, the competition for new GSAs is assumed to take place some years ahead of the market requirement, otherwise new entrants would not be able to supply in time and would not ever be able to enter the market. This matches the current reality and is an essential assumption if realistic projections are to be made. However, it does also mean that the model reflects an “orderly development” scenario in which demand and supply are never significantly misaligned, for example to the extent that additional supply is needed at short notice or demand falls below GSA “take-or-pay” levels.

This model of competition is not forward looking in the sense of explicitly considering multiple periods, because of the difficulty of defining what the appropriate multiples are. However, repeated competition for single periods by producers whose potential capacity and cost parameters change slowly produces results that look very similar to multi-period competition.

Although, GSAs are typically for gas ex-plant, the markets are effectively at the city gates, where the price of gas is the ex-plant price plus the transmission cost. Competition is therefore modelled at the city gate and transmission costs are included as a cost of production. This is consistent with the current transmission paradigm under which pipelines are price regulated or subject to threat of regulation. Further work is required to develop models with explicit transmission price competition.

A.4 GSA price formation

In negotiating new sales agreements the commercial objectives of the producers are to maximise their profits, by controlling volumes and prices, subject to competitive pressures exerted by other existing and new producers and by the willingness of the market to buy gas at those volumes and prices.

The buyers’ commercial objectives are likewise to maximise their profits, which is generally equivalent to minimising their supply costs, including transmission. By negotiating several years ahead of the market’s requirement for new gas, buyers can involve new entrants, without whose presence in negotiations the incumbents would have greater market power and would extract higher prices.

Gas producer competition is consequently a type of game, a situation in which two or more players make decisions contingent on the other players’ decisions. MMAGas therefore models the gas market, i.e. the competition between producers to contract for new GSAs, as a Nash-Cournot game between the producers, this being a mathematically tractable game model that is particularly suited to modelling competition between a limited numbers of players.

Game theory models have been extensively applied to electricity markets[38] but their application to gas markets appears very limited. At the time we initiated MMAGas development we were not aware of any similar gas models but have since discovered the work of Gabriel et al[39], who have built a model of the North American market in which the producers are modelled as being in perfect competition and marketers/shippers are modelled as Nash Cournot players with market power. Our assumptions about sector competitiveness are the reverse, which we believe are more appropriate in the Australian market.

A.5 MMAGas Structure

MMAGas replicates the essential structure of the Australian gas market. Particular emphasis is placed on ensuring that gas supply is rational, for example capacity investments are made only when there are sufficient remaining reserves for the investment to earn a return. This, combined with the Nash-Cournot game solution, ensures that all capacity investments projected in MMAGas are automatically economic i.e. earn a return at least equal to producers' cost of capital.

The following sections describe the "default" version of MMAGas in which new GSAs have a ten year term and the competition periods are annual.

A.5.1 Demand

Demand is specified for a number of different zones, with demand in each zone treated as if at a point, so there is a single transmission cost from each producer to each zone. The zones are primarily the state gas markets, with further subdivisions as necessary to accurately differentiate intra-state transmission costs.

The Eastern states model has eight demand zones, shown in Table A- 1. MMAGas can readily accommodate additional Eastern states zones, the major limitation being availability of disaggregated forecasts. Versions including Western Australia and LNG exports have also been developed.

Table A- 1 Eastern states demand zones and nodes

Zone	Node
NSW and ACT	Sydney
Victoria	Melbourne
SE Queensland	Brisbane

38 See for example: "Network-constrained Cournot models of liberalised electricity markets: the devil is in the details". K Neuhoff, JBarquin, MG Boots, A Ehrenmann, BF Hobbs, FAM RIjkers and M Vasquez. Energy Economics May 2005. Also "Game Theory Models in Plexos". Michael S Blake, Drayton Analytics, 2003.

39 "A large scale linear complementarity model of the North American natural gas market", SA Gabriel, J Zhuang, S Kiet, Energy Economics July 2005.

Central Queensland	Gladstone
NE Queensland	Townsville
NW Queensland	Mt Isa
Queensland CSG	Tarong
South Australia	Adelaide
Tasmania	Bell Bay
LNG exports	Gladstone

Underlying demand projections for each market zone are input. Underlying projections means projections at current prices, which are price adjusted to match supply. Each market is characterised by a price elasticity, which depends largely upon the balance of demand in various sectors. SKM MMA's projections are generally derived from separate consideration of projections of utility demand (residential, commercial and small industrial), large industrial demand and projections of gas usage for power generation (GPG).

A.5.2 Gas production

The Eastern states model incorporates twenty competing producers. In MMAGas producers are physically independent gas producers, such as the BHPB-Esso JV in Gippsland and the Santos led JV in the Cooper Basin. It is assumed that the JVs have sufficiently different ownership mixes that they operate commercially independently, i.e. bid competitively, regardless of common ownership. We believe this will be reasonably true in future though it may not have been under the state-by-state monopoly conditions in the past. Alternative assumptions about production competition have been investigated and can be modelled.

A.5.3 Gas reserves

Each producer's existing 2P (proved and probable) gas reserves are split into two tranches, lower production cost (Tranche 1) and higher production cost (Tranche 2), corresponding broadly to reserves that are commercial at current prices and uncommercial reserves. Initial T1 and T2 gas reserves are input as data.

Future gas discoveries are dealt with using a simple sub-model based on estimated undiscovered resources (choice of P80, P50 and P20 values i.e. 80%, 50% and 20% probability of exceedance over the next thirty years, assuming steady exploration expenditure). The sub-model adds new gas discoveries to each producer's reserves, up to the selected level of undiscovered resources, with timing of discoveries determined by a value index related to remaining reserves and costs of exploration. Discoveries are added to both T1 and T2 reserves.

Each year reserves are decreased by the quantity produced and increased by new discoveries.

A.5.4 Production costs

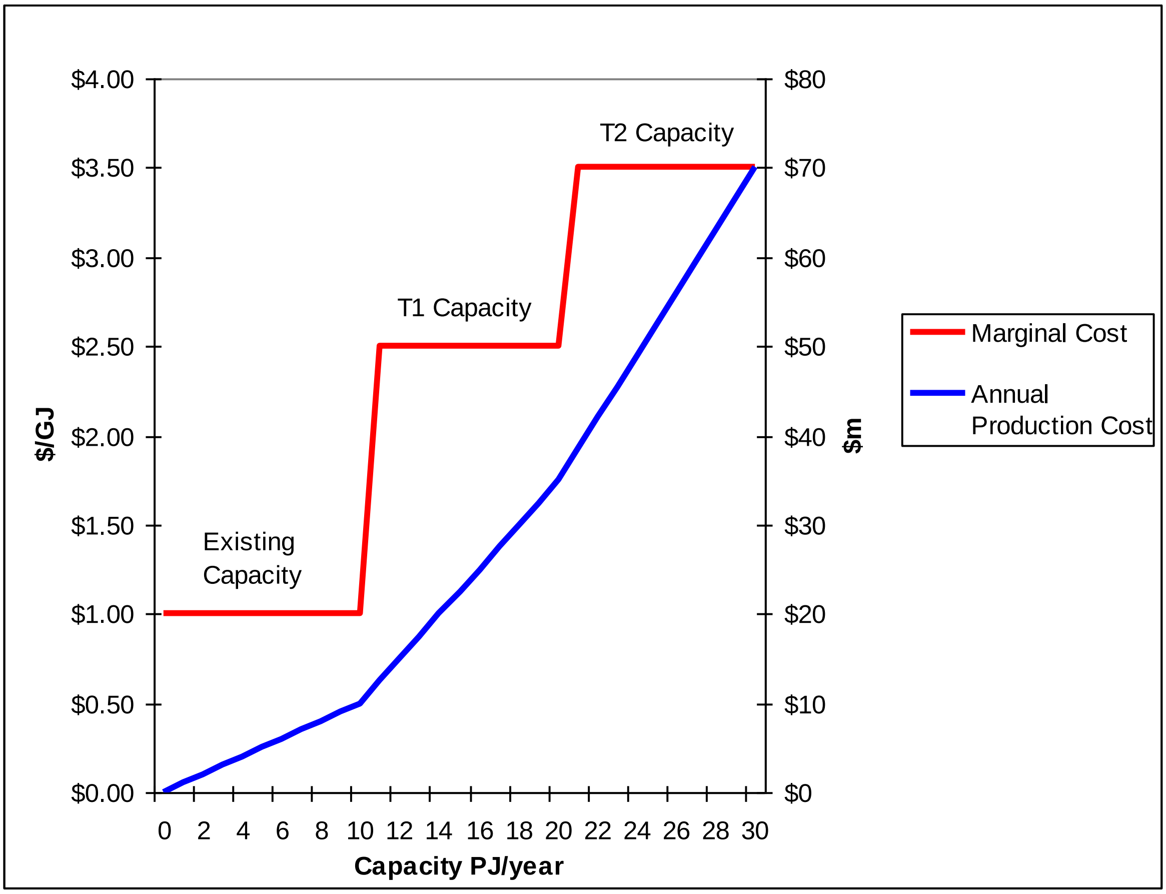
MMAGas focuses on producer's costs of supplying new GSAs over a fixed term of ten to fifteen years. These costs are determined by whether the incremental capacity used to supply the new GSAs is existing capacity or potential incremental capacity available from uncontracted T1 and T2 reserves. Each producer's new GSA supply cost function is therefore specified by the marginal costs of incremental production from existing capacity (short-run marginal cost), potential T1 capacity (long-run T1 marginal cost) and potential T2 capacity (long-run T2 marginal cost, higher than T1).

Figure A- 3illustrates a typical MMAGas production cost function for a producer with the ability to supply new GSAs up to 10 PJ/yr from each of existing, potential T1 and potential T2 capacity. The production cost functions are redefined each year to reflect changes in uncontracted reserves. Each producer's ability to supply is constrained only by its costs – in MMAGas implementation the cost of production beyond T2 is simply set at an uncompetitive level to ensure that capacity used never goes beyond T2.

Further realism is added by splitting capacity/costs into field capacity/costs and processing capacity/costs. Field capacity is assumed to be tied to a GSA i.e. new GSAs generally need new field capacity but processing capacity is assumed to last for thirty years.

All production costs are inputs. As the model is a long-term model, producer costs include annualised costs of capital (typically assumed to be 12% real pre-tax) and are based on an assumed "market" load factor e.g. 85%.

▪ **Figure A- 3 MMAGas production cost function**



Productions costs are generally assumed to be fixed in real terms into the future but can be varied up or down to reflect underlying cost changes due to exchange rates or technical developments. Cost increases due to use of reserves that are more expensive to develop are taken into account by the T1/T2 split.

Initial gas production and processing capacity attributable to each producer are also input as data. Default data is based on SKM MMA information.

A.5.5 Transmission costs

In the current version of MMAGas transmission pipelines are treated as a common carriage system used by producers. Transmission contracts are not dealt with explicitly but new transmission contracts are created implicitly each time a new GSA between a producer and a market is created.

Transmission costs are added to production costs to determine producer competitiveness in each market. In view of the long-term nature of MMAGas there are no transmission constraints because transmission capacity has to be expanded to meet demand, in the same way production capacity is expanded. Costs are expressed in $/GJ throughput terms, with the same costs for existing and new capacity.

Transmission costs are inputted as costs for specific pipelines, e.g. Roma-Brisbane pipeline, and combined to form producer-to-market transmission costs. The values used are based on regulated or voluntary third party tariffs, where these are published; otherwise MMA estimates based on construction costs are used.

A.5.6 Gas supply agreements

Existing GSAs

Volumes and prices of existing GSAs are inputted as data. SKM MMA's GSA database is used to allocate volumes available under GSAs to each market.

New GSAs

For each year in the projection period the GSA shortfall/surplus relative to demand in each market zone is calculated. The shortfall can be calculated relative to GSA volumes anywhere from ACQ (annual contract quantity) down to take-or-pay, typically 80% of ACQ.

Producers compete to meet the GSA shortfalls in that year. In some years there is no shortfall in some zones and in other years there are substantial shortfalls as GSAs terminate. When the shortfall is measured against GSA volumes below ACQ, the residual volumes of gas available under existing GSAs compete with new GSAs to supply the shortfall quantity, with the cost of supply under existing GSAs set at the short-run marginal cost.

Each producer's competitive objective is to maximise its profit subject to the volume/price constraints imposed by competitors. Their profits are the sum of revenue in each market (volume x market price at city gate) less their long-run incremental production costs and transmission costs to each market. Competition is across all zones simultaneously. The model automatically seeks to supply from existing capacity, followed by T1 reserves until they are fully contracted and lastly from T2 reserves.

Profit maximising incremental GSA volumes and market prices are estimated according to the Nash-Cournot game methodology, together with price adjusted demand forecasts. New GSA prices at the plant gate are market prices less transmission costs. The new GSA price always exceeds the production costs, otherwise the incremental gas quantity would be zero, and consequently the new production is guaranteed to be economic at the margin, i.e. to earn a return at least equal to the producer's cost of capital embedded in its costs. The excess profit margins are, at least in part, used to cover other producer costs such as exploration.

Incremental GSA volumes are assumed to be contracted for ten years. Consistent with this assumption, producers cannot contract more than 10% of their remaining uncontracted reserves in any year. The plant gate price is also locked in for the ten years. The new GSAs are added to existing GSAs and the process is repeated for the following year, thus building up layers of new GSAs, as illustrated in Figure A- 1.