B Eastern Australian gas market model

The Productivity Commission has developed a partial equilibrium model that is designed to capture the underlying economic fundamentals of the eastern Australian gas market.

The aim of the modelling work is to contribute to the Commission's research and the policy debate more broadly through:

1. demonstrating the long-term effects of linkage to international gas markets through development of liquefied natural gas (LNG) export capacity, including the effects on various gas market participants in different parts of the eastern Australian gas market
2. investigating the effects of current and proposed gas market policies, including coal seam gas (CSG) moratoria and domestic gas reservation, as well as the implications if gas market regulation were to cause delays in transmission pipeline investment
3. publishing the full details of the model to allow other users to extend and adapt the model for other purposes.[1]

Policy insights are the focus of the modelling work and priority has been given to ensuring that the model is as simple as possible to achieve this objective, facilitating transparency in the modelling approach and use of data. The model has not been designed to capture the full engineering detail of the gas transmission network or all the complexities of the eastern Australian gas market. Nor is the model intended to be used to optimise the operation and design of the transmission network, to forecast gas prices or to evaluate potential investment proposals. The purpose of the model is to capture the economic fundamentals as they would apply in an efficient market or a market subject to policy intervention.

B.1 The model framework

The model captures both the supply and demand sides of the eastern Australian gas market. Gas production, processing, transmission, storage and LNG conversion are identified as separate activities in the supply chain (figure B.1). Demand for gas is also disaggregated into demand from electricity generators, industry and mass market users. Gas distribution and retail are not explicitly identified. Retail margins and distribution costs are not expected to change substantially as a consequence of linking between the eastern

[1] The GAMS model code and data developed for this project are available on request. Requests should be directed to gas.markets@pc.gov.au.

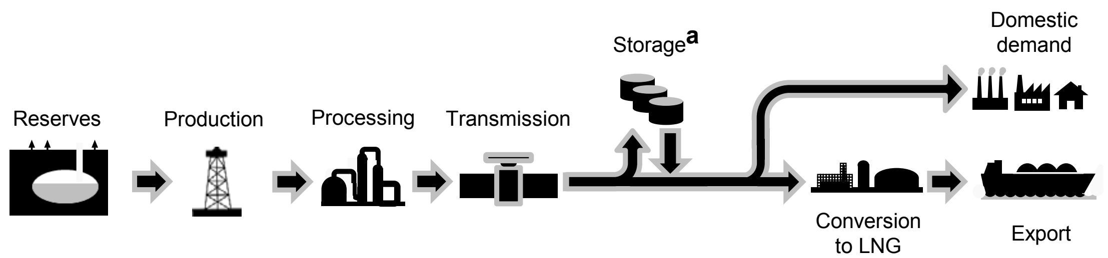
Australian gas market and international markets or from the policy options investigated, so the focus is on the wholesale gas market.

Geographical and temporal detail in the model

The level of geographical detail represented is illustrated in figure B.2. This simplified representation captures key transmission pipelines that link major supply basins and demand centres in the eastern Australian gas market. Supply basins and demand centres are represented by 'nodes' in the model. Each supply basin contains up to ten fields, with production from each field limited by the quantity of gas reserves recoverable from that field. The Moranbah Gas Project — as well as demand that this project serves at Moranbah and Townsville — is not included as it is not physically connected to the rest of the eastern Australian gas market. Other gas reserves in the Bowen basin are included as part of the Surat–Bowen basins.[2]

The model is dynamic, covering a period of 40 years. For each year there are two seasons (a three month winter from June to August and a 9 month 'summer' from September to May), with the first period commencing in September 2012. Data from the Australian Energy Market Operator (AEMO) indicate that in Melbourne and Sydney — the two cities that consume the most gas in the eastern market — mass market demand peaks over the three-month period between June and August each year (pers. comm., 12 November 2014). Separating each year into two seasons allows pipeline and supply constraints during periods of high demand in winter to be captured without a substantial increase in the size and complexity of the model. The modelling is not designed to capture issues in meeting daily demand and so factors that are relevant for meeting daily peak flows but not seasonal peaks (in particular, linepack on transmission pipelines and LNG storage) are not included.

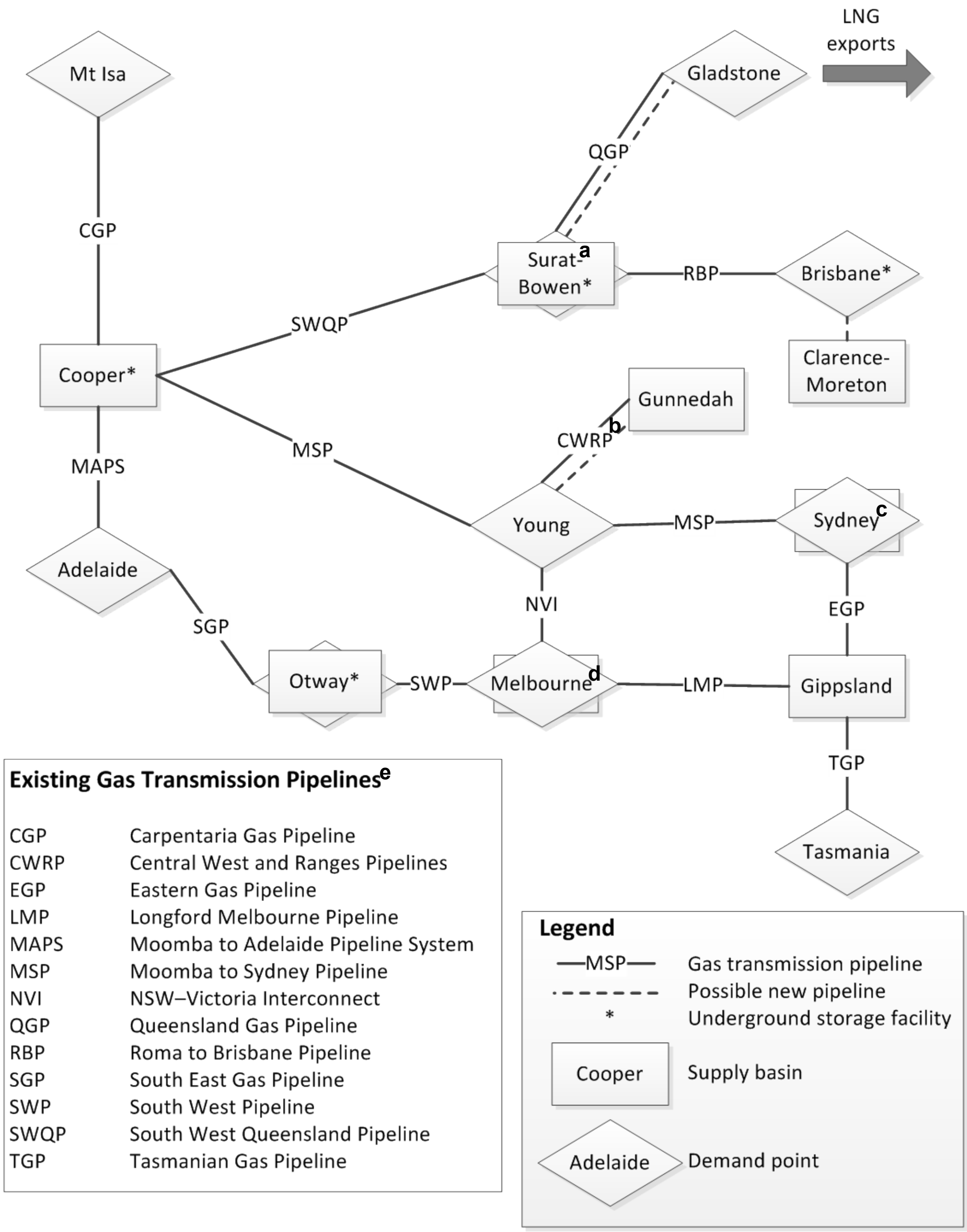
Figure B.1 **Gas supply chain as modelled**



[a] Storage can occur either after transmission (for example, at Brisbane) or prior to transmission (for example, in the Cooper basin).

2 Just under 1000 petajoules of 2P reserves associated with the Moranbah Gas Project are excluded from the model (of a total of more than 9000 petajoules of reserves in the Bowen basin as at 30 June 2014 (DNRM 2015a)).

Figure B.2 **Eastern Australian gas market model topology**



[a] Excludes the Moranbah Gas Project but includes potential new production in the northern Bowen basin. The Galilee basin was not modelled, as 2P reserves are not projected to be available before 2040. [b] Central West and Central Ranges pipelines are modelled as a single pipeline connecting to the Moomba to Sydney Pipeline at Young. [c] The Sydney and Gloucester gas basins are modelled as part of the Sydney region, as is demand at Canberra and Hoskintown. [d] Bass basin gas production and processing at Lang Lang modelled as part of the Melbourne region. [e] Simplified representation but based on data for actual pipelines. For example, QSN Link is not modelled separately from the South West Queensland Pipeline. The Northern Queensland Gas Pipeline is not modelled.

Solving the model

The framework is that of a partial equilibrium model in the sense that not all industries in the economy are represented and there is no representation of income effects (such as changes in purchasing ability in other markets resulting from price changes in the eastern Australian gas market) and their second-round effects on consumption decisions. This approach is well-suited to modelling gas markets, as it allows explicit representation of spatial and temporal linkages. It also allows for physical constraints — such as gas basin reserves or transmission pipeline capacity limits — and policy constraints to be explicitly captured in a way that they are generally not in computable general equilibrium models.

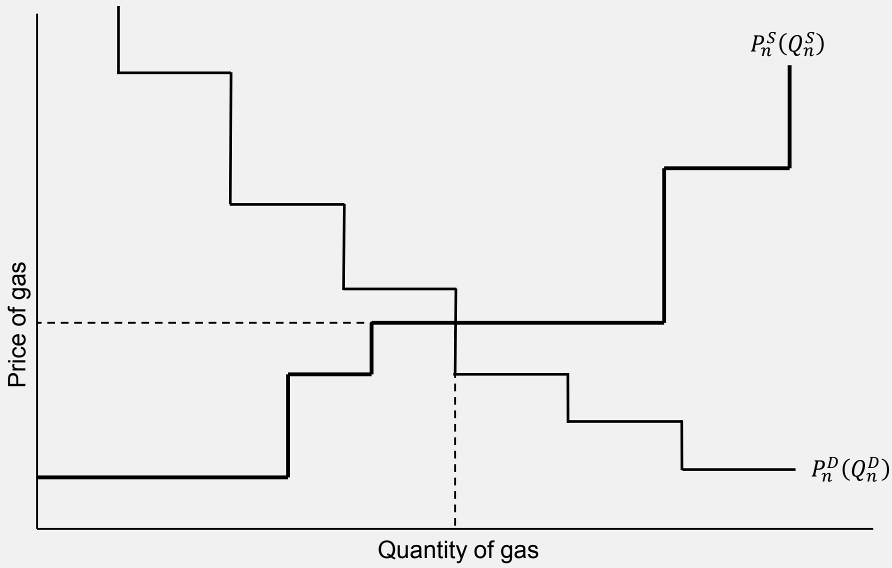
The theoretical framework for the model is based on the spatial and temporal equilibrium framework developed by Takayama and Judge (1971). There is a wide body of literature applying this framework to various policy environments from airport regulation to agricultural, water and environmental issues. There have also been a number of Australian and international applications of this framework to natural gas supply and transportation (for example, ACIL Allen Consulting 2014b; Gabriel, Manik and Vikas 2003; Loulou et al. 2005; Sohl 1985; Wagner 2014). The model is solved in a primal (quantity) formulation, with prices (all in real 2014-15 dollars) given by the shadow prices (Lagrange multipliers) for constraints.

Competitive market equilibrium in the eastern Australian gas market is computed by maximising the area under the demand functions less the cost of supplying gas, subject to any supply and policy constraints. This is equivalent to gross consumer benefit less total cost of supply, including any imputed economic rents from resource and policy constraints (Pressman 1970). This maximisation problem is subject to the commodity balance constraint, whereby the quantity of gas demanded at each node must be less than or equal to the quantity supplied (the quantity supplied includes the quantity of gas shipped to each node through transmission pipelines and excludes any gas shipped out of that node) (box B.1). This approach allows for competing sources of supply to be evaluated simultaneously, with gas supplied from the least cost sources first.

The demand functions in the model represent the 'willingness to pay' for gas by gas users. Where gas is used as an input to produce other goods, the demand function incorporates the implicit value placed on the gas by purchasers of those other goods. For example, where gas is used as a feedstock to produce chemical or plastic products, the willingness to pay from firms that use gas as a feedstock partly reflects the value that their customers place on the chemical or plastic products that they produce (as well as the costs of production to meet downstream demand).

Box B.1 **Stylised representation of the modelling framework**

The figure below provides a stylised example of the supply–demand balance in a gas market.



The point at which demand intersects supply (market equilibrium) can be found by maximising the area under the demand function less the area under the supply function and solving for the equilibrium quantity. This is equivalent to maximising net social welfare (NSW):

$$Max\ NSW = \sum_n \int P_n^D(Q_n^D)dQ_n^D - \sum_n \int P_n^S(Q_n^S)dQ_n^S$$

This is subject to the supply–demand balance constraints for each point in the network (node) in each time period:

$$Q_n^D \leq Q_n^S + \sum_m (1 - loss_{m,n})TRANS_{m,n} - \sum_m TRANS_{n,m}$$

and other constraints on the quantity of gas supplied and flows on each pipeline route:

$$TRANS_{m,n} \leq PIPECAP_{m,n};$$

$$Q_n^S \leq SUPCAP_n$$

where:

Q_n^D , Q_n^S	= quantity demanded and supplied at node *n* (also $Q_n^D \geq 0$ and $Q_n^S \geq 0$)
P_n^D , P_n^S	= price of demand and supply at node *n*
$loss_{m,n}$	= system use of gas on pipeline from node *m* to *n*
$TRANS_{m,n}$	= quantity of gas transported from *m* to *n*
$PIPECAP_{m,n}$	= pipeline capacity from *m* to *n*
$SUPCAP_n$	= supply capacity from node *n*

Karush–Kuhn–Tucker conditions define the necessary conditions for a solution to this stylised model, which reveal the equilibrium conditions imbedded in the model, key elements of which

(continued next page)

Box B.1 (continued)

are set out in selected complementary slackness and first order conditions below (derived by taking the derivative of the Lagrangian ($\mathcal{L}$) with respect to Q_n^S and $TRANS_{m,n}$ respectively).

$$\left(\frac{d\mathcal{L}}{Q_n^S}\right) Q_n^S = 0 \qquad \text{and} \qquad \lambda_n^{DSBAL} - \lambda_n^{SUP} - P_n^S \leq 0$$

$$\left(\frac{d\mathcal{L}}{dTRANS_{m,n}}\right) TRANS_{m,n} = 0 \qquad \text{and} \quad \lambda_n^{DSBAL}\left(1 - loss_{m,n}\right) - \lambda_m^{DSBAL} - \lambda_{m,n}^{PIPE} \leq 0$$

where:

λ_n^{DSBAL} = lagrange multiplier on supply–demand balance equation, equal to the demand price to gas users

$\lambda_{m,n}^{SUP}$, λ_n^{PIPE} = shadow price of gas supply and transmission pipeline constraints.

The first set of conditions indicate that if a positive quantity of gas is supplied, then the demand price is equal to the cost of supply (the supply price plus the shadow price of any supply constraints). If no gas is supplied, then the demand price is less than or equal to the cost of supply.

The second set of conditions indicate that if gas is transported between two different locations, then prices at those two locations will diverge by an amount equal to the system use of gas multiplied by the gas price at the receiving end, plus the shadow price of any transmission pipeline constraints. If no gas is transported, then prices at those two locations must diverge by this amount or less.

Although the model is more complex than this stylised illustration, the principles are the same. Demand functions are represented by a linear approximation of constant elasticity of demand functions, with demand functions linearised using the approach set out in PC (2011). The equilibrium prices and quantities in each season and market are those that maximise the objective function subject to the following constraints:

- the quantity of gas demanded at each node in each season is less than or equal to the quantity of gas supplied to each node in each season (after accounting for shipping, storage and system use of gas in transmission)
- the total quantity of gas produced at each field is less than or equal to proved and probable reserves in each field
- the quantity of gas produced, processed, transmitted, stored or liquefied in any season is less than or equal to the relevant capacity for a given field, processing plant, pipeline, storage facility or liquefaction plant (respectively) in that season
- the quantity of gas in storage is greater than or equal to zero at each storage facility in each season
- cumulative investment to expand pipelines and to add trains to existing LNG facilities is less than or equal to physical limits on expansion; investment in new storage capacity is constrained to locations where there is already existing underground storage. (There are no constraints placed on investments to increase production, processing or new LNG capacity.)
- new pipelines must be built according to a binary yes/no decision to build a particular pipeline size.[3]

[3] Solution times are slowed by the inclusion of many binary variables, so new pipelines were restricted to two different sizes along three specific routes (see transmission data section below).

A competitive equilibrium is used to generate outcomes in an efficient market. The aim is not to predict short-term prices and volumes. Further, the approach does not reflect a judgment that the eastern Australian gas market achieves a competitive equilibrium in practice. A comprehensive assessment of the existence and exercise of market power in upstream gas markets is outside the scope of this project. Nonetheless, the framework adopted is useful to illustrate the underlying economic fundamentals of the eastern Australian gas market following linkage to the Asia–Pacific market, and the effects of selected policies. A competitive market model is used on the basis that this does not invalidate the use of the model to demonstrate the long-term effects of linkage to international gas markets and to investigate the effects of current and proposed gas market policies.

Relationship between gas prices across geographical locations and time

The model yields information about gas supply, demand, prices and investment across geographical locations within the eastern Australian gas market. Gas is allocated across space and time so that arbitrage opportunities are exploited fully and there are no further gains from trade possible.

Gas prices in different locations

The constraints in box B.1 are a stylised representation of the model, but nonetheless the equilibrium conditions capture the key arbitrage conditions that determine prices across different locations in the model. The key points of these conditions are outlined below.

Where there is sufficient pipeline capacity, gas will be transported from locations where gas is cheaper to locations where gas is more expensive, provided that the difference in price exceeds the cost of transport. The opportunity cost of transport is derived from the system use of gas. This means that in a network with ample spare pipeline capacity, price differences across regions will be less than or equal to the variable cost of transmission.

Where the demand to ship gas exceeds pipeline capacity, the pipeline will operate at capacity and a capacity rent will be set that rations use of the pipeline to the highest bidders (taking into account the potential for customers to source gas from elsewhere). The price then charged for the use of the pipeline will exceed the variable cost of transmission. Price differences across regions can exceed the variable cost of transmission and there might be an incentive for investment in new transmission capacity (discussed below).

Gas prices and storage

Gas storage provides a means to arbitrage between gas prices over time. Again, different outcomes are possible depending on how much storage capacity is available.

Where there is sufficient storage capacity, gas will be injected into storage during periods where gas prices are low and extracted during periods where prices are higher. If gas storage is not constrained, prices across different periods will not diverge by more than the variable cost of storage.

Gas in storage will have lower (cushion gas) and upper (maximum storage) limits that may constrain the use of storage to limit price fluctuations over time. Under these circumstances capacity rents accrue to storages that are constrained, prices across different periods can diverge by more than the variable cost of storage and there might be incentives for investment in additional storage capacity.

Investment decisions

Investment in new production, processing, transmission, storage and LNG facilities is also an important factor in determining gas prices over time and across geographic locations. The quantity and timing of investment to increase capacity in each of these parts of the gas supply chain is determined endogenously. Investment decisions are dynamically efficient in that investments are made when the total expected benefits (in terms of greater gas production, transmission, storage or liquefaction capacity) outweigh the full economic investment costs in net present value terms.

For example, transmission investment occurs when the present value of future capacity rents associated with constraints on pipeline capacity exceed the cost of new investment. Where investment is not constrained, pipeline investment occurs up to the point where the pipeline owner just recoups their investment costs. Investment will not remove capacity constraints (and rents) altogether as this would mean the investor would not be able to recoup their investment costs.

Policy options

The approach taken allows the effects of policies to be evaluated by imposing constraints on the model and for the effects of any policies on market prices (the 'shadow price' associated with the policy constraint) to be determined. Differences between policy and baseline simulations can be used to estimate the effects of policy settings on the welfare of consumers and producers in the eastern Australian gas market,[4] and on market outcomes including prices, production and investment.

4 The economic welfare measure used in reporting of modelling results is the sum of Marshallian consumer and producer surplus. This measure excludes welfare changes in other markets resulting from income effects and broader externalities not included in the model, such as environmental effects of gas production and supply.

The following policy options have been modelled.

- *CSG moratoria*: no investment in new CSG production is allowed in New South Wales or Victoria
  - in baseline scenarios, no investment in new CSG production is allowed in New South Wales or Victoria before September 2015, reflecting current policy settings in those states (chapter 5)
  - under the policy simulation, no investment in new CSG production is allowed in New South Wales or Victoria throughout the entire simulation period.
- *Domestic gas reservation*: any new fields not producing gas in year one are required to supply a specified proportion of their gas production to domestic users as they begin production (that is, fields that are already producing gas are not subject to reservation).
- *Delays in transmission pipeline investment*: investment in expansion or construction of transmission pipelines that are potentially subject to regulatory coverage are delayed by 5 years between investment and commissioning (in addition to the usual time taken to build and operationalise new transmission assets).

For each policy option, three different scenarios have been considered based on different estimates for LNG prices: a 'low LNG price' scenario, a 'central LNG price' scenario and a 'high LNG price' scenario.

The purpose of these three scenarios is to capture the implications of uncertainty regarding the future price of LNG exports. For other key parameters, such as future reserves growth, gas production costs and price elasticities of demand, sensitivity analysis has been conducted and is reported in appendix C.

B.2 Data used for model calibration

The level of geographical, temporal and supply chain detail in the model determines the data requirements to calibrate the model. For each stage of the supply chain (production, processing, transmission, storage and LNG conversion) there is a need to specify:

- variable and fixed operating costs (including gas usage in transmission and LNG conversion)[5]
- current seasonal throughput or storage capacity
- investment cost, build time, lifetime and any investment limits for investment to expand capacity.

5 All costs and prices expressed in this appendix are in 2014-15 Australian dollars unless otherwise indicated. Where relevant, prices have been inflated to 2014-15 dollars using the latest available ABS GDP implicit price deflator for the September 2014 quarter.

Demand data are required for electricity generation, industry and mass market use at each demand location. Data are also required for projections of exogenous parameters over the 40 year simulation period. For example, demand growth, international LNG prices and any increases in gas reserves from exploration are required to calibrate parameters in the model.

Approach to data compilation

The objective in compiling data for model calibration has been to collect the best publicly available data that can be referenced to reputable sources. The following steps have been taken to ensure the best available data were used.

- Detailed review of publicly available data sources, with comparison across multiple sources where possible.
- Consultation with industry participants as part of the project.
- Feedback from two referees and other participants at a modelling workshop held on 4 February 2015, based on a workshop paper that set out the database used for preliminary modelling work.
- Assistance and additional data from AEMO on pipeline flows and gas demand forecasts.
- Support from the Core Energy Group in developing updated estimates of the costs of gas production.

Data sources and methodology are presented below for demand for gas and for each of the components of the gas supply chain modelled. A real discount rate of 6 per cent was used to aggregate the objective function over time.

Gas production

In the long term, gas production is constrained according to gas reserves in each field. In the short term, gas production is constrained by well deliverability limits, captured in initial production capacity for each field.

Gas reserves

Data on gas reserves for each of the 35 fields are required to set constraints on the total amount of gas that can be produced from each field (table B.1).[6] There are a range of

[6] Fields included in the model are based on the classification in Core Energy Group's (2012a) analysis of production costs for AEMO.

different gas resource estimates, which are generally classified according to the Petroleum Resources Management System (SPE 2007).

Table B.1 **Data used for reserves and growth in reserves**

Basin	*Field*	*Gas source*	*2P reserves (PJ, Jun 2014)*	*Annual increase in 2P reserves (PJ)*[a]
Bass	Yolla	Conventional	221	8
Bass	New offshore	Conventional	0	144
Clarence-Moreton	New CSG	CSG	17	83
Cooper	Conventional	Conventional	1 047	1
Cooper	New shale	Shale	5	168
Cooper	New infill	Conventional	0	36
Cooper	New CSG	CSG	0	49
Cooper	GLNG	Conventional	745	0
Gippsland	GBJV and Turrum	Conventional	2 854	58
Gippsland	Kipper	Conventional	558	8
Gippsland	Longtom	Conventional	116	3
Gippsland	New unconventional	CSG	0	15
Gippsland	New offshore	Conventional	0	74
Gloucester	Gloucester (CSG)	CSG	527	11
Gunnedah	New CSG tier 1	CSG	799	135
Gunnedah	New CSG tier 2	CSG	0	17
Otway	Casino/Henry/Netherby	Conventional	189	3
Otway	Otway Gas Project	Conventional	453	2
Otway	Minerva	Conventional	76	0
Otway	Halladale/Blackwatch	Conventional	0	1
Otway	New CSG	CSG	1	0
Surat–Bowen	Conventional	Conventional	97	6
Surat–Bowen	Moranbah[b]	CSG	847	14
Surat–Bowen	Fairview/Spring Gully	CSG	1 501	0
Surat–Bowen	Walloons East	CSG	2 665	0
Surat–Bowen	Walloons Mid	CSG	367	72
Surat–Bowen	Walloons West	CSG	461	111
Surat–Bowen	Ironbark	CSG	229	33
Surat–Bowen	QCLNG	CSG	13 293	167
Surat–Bowen	APLNG	CSG	11 189	318
Surat–Bowen	GLNG	CSG	6 239	60
Surat–Bowen	Arrow Energy	CSG	7 832	537
Sydney	Camden	CSG	43	1
Sydney	Hunter Area	CSG	42	1
Sydney	New CSG	CSG	17	47

[a] Applied to gross reserves (that is, reserves before depletion through production) for each year of the simulation period. [b] Excluded from modelling.

Sources: Commission estimates based on AEMO (2012c), Core Energy Group (2012a, 2013a, 2015b) and DNRM (2015a).

All proved and probable ('2P') reserves are available for production, as this covers all reserves that are commercial, with a 50 per cent chance that actual quantities recovered will be greater than this estimate. 2P reserves excludes 'possible' reserves (which have a lower probability of production) and non-commercial contingent or prospective resources (reserves are the subset of resources that are anticipated to be commercially recoverable).

Exploration to find new resources and to 'prove up' contingent and prospective resources to 2P standard is important in determining future reserve availability, so data are also required on potential increases of 2P reserves during the simulation period. In practice, there will be a link between market prices and the economy of proving up gas resources. However, this link has not been included due to a lack of data on the extent of market price increases required to make contingent resources in different fields commercial.

Unfortunately, consistent data on 2P reserves by field throughout the entire eastern Australian gas market and projections for future reserves growth are also not available. To obtain up-to-date estimates on a consistent basis, a combination of data sources were used.

- Existing 2P reserves were primarily based on estimates in Core Energy Group (2015b) for reserves by basin as at June 2014.
  - Basin-wide reserves were allocated across different fields according to data on reserves by field in Core Energy Group (2012a).
  - Further data on reserves at a disaggregated field level as at June 2014 were available for Queensland (DNRM 2015a), which were used in conjunction with the field classifications in Core Energy Group (2012a) to allocate reserves across different fields within the Surat–Bowen basins.
- Projections for growth in 2P reserves were primarily based on annual averages of basin-wide projections for the period 2013 to 2038 in AEMO (2012c).
  - Projections by basin were updated on a pro rata basis to match the latest projections for the whole of the eastern Australian gas market from AEMO contained in the 2013 Gas Statement of Opportunities (Core Energy Group 2013a).
  - Growth in reserves by basin were allocated across fields in proportion to the quantity of possible, contingent and prospective resources available to be proven up to 2P in each field. Possible reserves and contingent and prospective resource estimates by field were obtained using estimates of the quantity of potentially recoverable resources — less reserves that are already classified as 2P — from Core Energy Group (2012a).
  - There is considerable uncertainty about reserves growth, the implications of which are investigated as part of sensitivity analysis (appendix C).

Terminal value for gas reserves

In models with a finite simulation period, gas reserves remaining at the end of the simulation period have a zero value unless a 'terminal condition' is applied. The inclusion of a terminal condition attaches some value to gas remaining in reserves at the end of the simulation period and can have important implications for variables (such as prices, investment and production) in the periods leading up to the terminal period. To reduce the importance of the terminal condition, the model is solved over 40 years and results reported for the first 20 years only.

There are three possible approaches to modelling a terminal condition (PC 2011).

4. An exogenously specified level for reserves in the terminal period. This is equivalent to a perfectly inelastic demand for terminal reserves.
5. An exogenous specified price for gas reserves in the terminal period. This is equivalent to a perfectly elastic demand for terminal reserves.
6. A response function, with the price of gas reserves in the terminal period being a function of the quantum of reserves remaining.

Connection of the eastern Australian gas market to the Asia–Pacific market through LNG exports is likely to mean that domestic prices will be set with regard to export prices, and gas production in Australia is likely to have a limited effect on long-term export prices. Therefore, the second approach above has been used to apply a terminal value to gas reserves remaining at the end of the simulation period. An estimated netback price (at the wellhead) has been applied to calculate a fixed price for remaining gas reserves by subtracting the long run marginal cost of liquefaction, transmission, and processing from the projected export price in the terminal period. The cost of production of gas in the terminal period is calculated based on the production capacity available at the end of the simulation period — costs of production in the terminal period are lower where production capacity is already available.[7]

Initial production capacity

Well deliverability constraints are represented in the model through specifying initial production capacity for each field (table B.2). Further production capacity in 2015 at fields used to supply LNG exports was estimated by setting additional production capacity equal to projected LNG gas use in that year (estimated as set out below), with additional capacity pro-rated across fields using Core Energy Group (2012a) projections of export supply in 2015. This approach is based on the assumption that there will be sufficient increases in production to supply LNG exports in 2015, but no additional production of 'ramp gas'.

Development of further production capacity from 2016 is determined endogenously. Development of further production capacity involves investment costs and takes time, each of which were estimated as set out below.

7 Reported model results are not particularly sensitive to terminal values. Increasing or decreasing terminal values by one third (33 per cent, based on uncertainty about future LNG prices) changes total supply and demand over the first twenty years by 2 per cent or less.

Table B.2 **Initial production capacity by field**

Basin	*Field*	*Gas source*	*Initial production capacity (PJ per year)*[a]	*Additional production capacity in 2015 (PJ per year)*[b]
Bass	Yolla	Conventional	18	0
Bass	New offshore	Conventional	0	0
Clarence-Moreton	New CSG	CSG	0	0
Cooper	Conventional	Conventional	88	0
Cooper	New shale	Shale	0	0
Cooper	New infill	Conventional	0	0
Cooper	New CSG	CSG	0	0
Cooper	GLNG	Conventional	0	10
Gippsland	GBJV and Turrum	Conventional	241	0
Gippsland	Kipper	Conventional	0	0
Gippsland	Longtom	Conventional	25	0
Gippsland	New unconventional	CSG	0	0
Gippsland	New offshore	Conventional	0	8
Gloucester	Gloucester (CSG)	CSG	0	0
Gunnedah	New CSG tier 1	CSG	0	0
Gunnedah	New CSG tier 2	CSG	0	0
Otway	Casino/Henry/Netherby	Conventional	34	0
Otway	Otway Gas Project	Conventional	40	0
Otway	Minerva	Conventional	23	0
Otway	Halladale/Blackwatch	Conventional	0	0
Otway	New CSG	CSG	0	0
Surat–Bowen	Conventional	Conventional	5	0
Surat–Bowen	Fairview/Spring Gully	CSG	105	0
Surat–Bowen	Walloons East	CSG	94	10
Surat–Bowen	Walloons Mid	CSG	0	0
Surat–Bowen	Walloons West	CSG	0	0
Surat–Bowen	Ironbark	CSG	0	0
Surat–Bowen	QCLNG	CSG	0	203
Surat–Bowen	APLNG	CSG	0	0
Surat–Bowen	GLNG	CSG	0	32
Surat–Bowen	Arrow Energy	CSG	0	0
Sydney	Camden	CSG	6	0
Sydney	Hunter Area	CSG	0	0
Sydney	New CSG	CSG	0	0

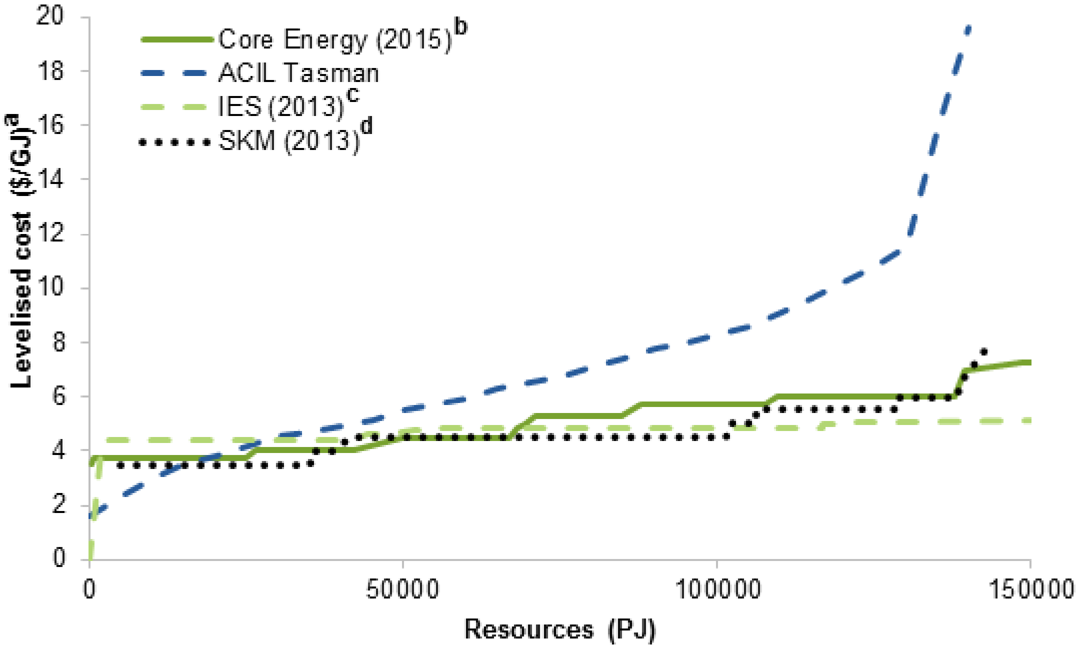
[a] Production capacity in 2013, to match the first year of the simulation period. [b] Increase in initial capacity of 263 PJ per year applied across QCLNG, APLNG and GLNG for 2015 to meet additional supply required for LNG exports.

Sources: Commission estimates based Jacobs SKM (2014b) and Core Energy Group (2012a).

Cost of gas production

There is substantial variation in publicly available estimates of the cost of producing and processing gas (figure B.3).[8] The cost of gas production from marginal fields differ by up to 100 per cent. This uncertainty is reflected in the range of supply costs included in the sensitivity analysis. Uncertainty is greatest regarding the cost of producing more speculative resources, including 3P and 2C resources.

Figure B.3 **Publicly available estimates of the cost of gas production**



[a] The levelised cost represents the average cost per GJ of producing and processing gas over the life of a gas field, including capital, operating and financing costs. [b] Gas resource estimates by field based on 'potential recoverable resource' from Core Energy Group (2012a). [c] Includes 2P, 3P, 2C and prospective resources. [d] Includes 2P, 3P and 2C resources.

Sources: ACIL Tasman (2013); Core Energy Group (2012a, 2015a); IES (2013); Wagner (2014); (SKM 2013b).

8 Production cost estimates include royalty payments (Core Energy Group 2015b). Accordingly, illustrative estimates of state royalty payments are calculated and added back to total welfare after the model is solved, based on state royalties being payable at 10 per cent of the wellhead value of gas (Government of South Australia 2014; NSW Trade & Investment 2015; Queensland Government 2015a; Victorian Gas Market Taskforce 2013b). More detailed modelling of royalty payments would require further model development to allow for deductible expenses under state royalty regimes.

Table B.3 Gas production cost estimates[a]

Basin	*Field*	*Operating, tax and royalty ($/GJ)*	*Upfront capital expenditure ($/GJ)*	*Future capital expenditure ($/GJ)*	*Total breakeven price ($/GJ)*
Bass	Yolla	2.3	1.7	0.0	4.1
Bass	New offshore	2.3	2.2	1.0	5.5
Clarence-Moreton	New CSG	2.4	3.1	2.7	8.3
Cooper	Conventional	3.5	0.4	1.4	5.3
Cooper	New shale	2.5	1.0	2.6	6.0
Cooper	New infill	1.8	0.8	2.6	5.3
Cooper	New CSG	2.0	1.6	2.1	5.7
Cooper	GLNG	3.5	0.4	1.4	5.3
Gippsland	GBJV and Turrum	2.4	1.5	0.7	4.5
Gippsland	Kipper	2.4	2.5	0.7	5.5
Gippsland	Longtom	2.4	1.5	0.7	4.5
Gippsland	New unconventional	3.5	2.1	1.7	7.4
Gippsland	New offshore	2.4	2.5	0.7	5.5
Gloucester	Gloucester (CSG)	2.1	2.0	0.9	5.0
Gunnedah	New CSG tier 1	2.2	1.2	3.2	6.5
Gunnedah	New CSG tier 2	2.4	1.3	3.5	7.3
Otway	Casino/Henry/Netherby	3.0	0.6	0.1	3.7
Otway	Otway Gas Project	3.0	0.6	0.1	3.7
Otway	Minerva	3.0	0.6	0.1	3.7
Otway	Halladale/Blackwatch	2.2	1.7	1.4	5.3
Otway	New CSG	3.5	2.1	1.7	7.4
Surat–Bowen	Conventional	3.5	0.4	1.4	5.3
Surat–Bowen	Fairview/Spring Gully	1.8	1.7	1.0	4.5
Surat–Bowen	Walloons East	1.8	2.3	2.0	6.0
Surat–Bowen	Walloons Mid	2.0	1.6	2.1	5.7
Surat–Bowen	Walloons West	3.3	3.3	1.9	8.5
Surat–Bowen	Ironbark	1.8	1.3	1.7	4.9
Surat–Bowen	QCLNG	1.3	2.2	1.6	5.1
Surat–Bowen	APLNG	1.6	1.8	1.5	5.0
Surat–Bowen	GLNG	2.7	2.3	1.7	6.6
Surat–Bowen	Arrow Energy	1.9	2.6	1.7	6.2[b]
Sydney	Camden	1.9	1.3	0.9	4.1
Sydney	Hunter Area	2.8	1.9	1.3	6.0
Sydney	New CSG	2.8	1.9	1.3	6.0

a Totals may not sum due to rounding. Costs converted into net present values per GJ of gas using a discount rate of 10 per cent. **b** Within the model, an additional $1/GJ was added to the capital cost of producing from Arrow Energy reserves to account for transmission costs of transporting gas from the Bowen basin (based on transmission costs in Core Energy Group (2015a)).

Sources: Core Energy Group estimates prepared for the Productivity Commission and consistent with Core Energy Group (2015a).

Central estimates of the costs of gas production were based on data provided by Core Energy Group (table B.3). These data are consistent with gas production cost data prepared for AEMO's 2015 Gas Statement of Opportunities (Core Energy Group 2015a), but with greater disaggregation to facilitate use in this report. Importantly, data provided to the Commission separate upfront capital expenditure from ongoing capital and operating expenditure.

Upfront capital expenditure was included as a single upfront investment cost. Investment costs have also been adjusted to account for higher required rates of return on investment than the discount rate used in the model, in order to account for investment risk in the gas industry (box B.2).

Box B.2 **Certainty equivalent uplift to investment costs**

A certainty equivalent uplift has been applied to investment costs to reflect risks associated with investment in production, processing or LNG facilities. Rather than investments proceeding on the basis of returns above the 6 per cent discount rate used in the model, this uplift means that a higher rate of return on investment costs would be required that is more consistent with investor behaviour in the natural gas industry.

Investment risk would ideally be modelled explicitly, but this would add substantial complexity to the model due to the need to represent multiple states. Instead, investment risk has been addressed by applying a certainty equivalent (Chandra 2009) uplift to investment costs for new or expanded gas production, processing and LNG facilities.[9] The uplift is calibrated to the difference in upfront investment costs required to obtain the same investment decision under a 6 per cent discount rate (the risk-free discount rate used to aggregate values over time in the objective function, which also governs intertemporal tradeoffs in investment decisions) as under a 12 per cent discount rate without the certainty equivalent uplift (for example, as applied in SKM (2013b)). The certainty equivalent uplift is applied under the assumption that the cost of an investment is evenly amortised over the life of the investment.

Sources: Chandra (2009); SKM (2013b).

Investment costs for production, processing and LNG facilities have not been truncated to account for economic lifetimes that continue beyond the terminal period (box B.3). There are two reasons for this.

7. The simulation period is 40 years, which is longer than the economic lifetime of these facilities, so only investment that occurs late in the simulation period would be affected by truncation.

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9 That is, investment risks on both the demand and supply side are reflected in an increase in supply cost parameters in the model. No certainty equivalent uplift was applied to investment in transmission pipelines. The real weighted average cost of capital for pipelines is likely to be lower than for upstream investments (see, for example, AER 2011a, 2012b, 2013b) so any certainty equivalent adjustment to the capital cost of pipelines would be smaller. Given this, and limited pipeline investment in model results (appendix C), the inclusion of a certainty equivalent adjustment to pipeline investment costs would not have a material effect on results.

8. Gas reserves might not be available in specific fields beyond the terminal period, so it is inappropriate to allocate part of the cost of these assets to periods where gas might not be available to recover those costs.

Remaining costs of gas production (operating, tax and royalty costs, as well as future capital expenditure) are classified either as variable costs — costs that vary with the quantity of gas produced — or fixed annual operating costs, which are independent of the quantity of gas produced within a single period.

For CSG production, there is limited scope to reduce operating costs by decreasing production. In practice, costs may increase if production ceases for a period, due to the risk of wells filling with water and costs associated with further dewatering. On this basis, variable costs for CSG production are taken to be negligible, with all ongoing annual costs fixed. Future capital expenditure is particularly important for CSG production.

For conventional and shale gas production, there is greater scope to vary production across seasons and all operating costs are assumed to be variable, reflecting a lack of data to enable separation of fixed annual operating costs from variable costs.

A build time of 3 years and an economic lifetime of 20 years was used for production assets (including wells, gathering lines and water treatment) in CSG fields. Build time estimates were based on recent CSG developments in Queensland (APLNG 2010; QGC 2009; Santos 2009), reflecting the period 2010 to 2013 required to reach more than 75 per cent of maximum production (Santos 2009) (that is, excluding initial production of ramp gas).[10] In practice, different production assets will have different lifetimes — for example, individual CSG wells might have a lifetime of 5 to 15 years, whereas gathering lines and water treatment facilities are likely to have longer lifetimes. There is no distinction made between different assets used in gas production, so a single lifetime estimate is used to capture the different components of gas production infrastructure, based on data from IES (2013).

An economic lifetime of 20 years is also used for conventional gas (and shale) fields, but following a build time of 5 years, based on the recent Wheatstone and Pluto projects in Western Australia (Chevron 2014b; Woodside 2009, 2012). No account is taken for considerable uncertainty in actual build times — for example, recent build times for conventional gas projects have ranged from 3 years for the Macedon Project (BHP Billiton 2007, 2013), to 6 years for the Gorgon Project (Chevron 2009, 2014a) and up to as long as 9 years for the Kipper Project (BHP Billiton 2007; ExxonMobil 2014).

[10] Production at full capacity is modelled to be possible at the end of the build time — ramp gas production is not included in the model.

Gas processing

Similar costs for gas processing are applied across all gas processing plants of similar technologies, with differences largely reflecting whether a plant primarily processes conventional gas or CSG (table B.4). Variable costs for processing conventional gas are used to estimate the variable cost of processing shale gas in the Cooper basin, as shale gas in this basin is likely to require similar processing to conventional gas in that basin (SKM 2013c). Initial processing capacities were based on AEMO's 2014 Gas Statement of Opportunities.[11]

A build time of 2 years was used for conventional and shale processing facilities, based on the time taken to expand the Moomba processing plant during 2014 and 2015. All basins that can produce conventional gas have existing processing facilities, so expansions are more relevant than greenfield investment. A build time of 1 year was used for CSG processing facilities, based on the timeframe for development of CSG processing capacity at Daandine (Gas Today 2009) and Tipton West (Australian Pipeline Trust 2006). An economic lifetime of 30 years was used for all processing facilities (based on ACIL Tasman 2013; APA Group 2010).

[11] Processing and transmission capacity data in this appendix is specified in PJ/yr (rather than TJ/day) for consistency with the rest of the gas supply chain and other parts of this report.

Table B.4 **Data for gas processing plants**

Basin	*Processing plant*	*Primary gas source*	*Initial capacity (PJ/yr)**a***	*Variable cost ($/GJ)**b***	*Unadjusted investment cost ($/GJ of annual capacity)**c***	*Certainty equivalent investment cost ($/GJ of annual capacity)*
Bass	Bass	Conventional	26	0.58	3.02	5.52
Clarence-Moreton	New	CSG	0	0.26	4.32	7.47
Cooper	Ballera & Moomba	Conventional	179	0.58	3.02	5.52
Cooper	New infill	Conventional	0	0.58	3.02	5.52.
Cooper	New shale	Shale	0	0.58	13.33	24.37
Gippsland	Gippsland	Conventional	455	0.58	3.02	5.52
Gippsland	New unconventional	CSG	0	0.26	4.32	7.47
Gloucester	Stratford	CSG	0	0.26	4.32	7.47
Gloucester	New	CSG	0	0.26	4.32	7.47
Gunnedah	Narrabri	CSG	0	0.26	4.32	7.47
Otway	Iona UGS	Conventional	73	0.58	3.02	5.52
Otway	Port Campbell	Conventional	126	0.58	3.02	5.52
Otway	New CSG	CSG	0	0.26	5.76	9.97
Surat–Bowen	Kincora & Yellowbank	Conventional	20	0.58	3.02	5.52
Surat–Bowen	Bellevue	CSG	110	0.26	4.32	7.47
Surat–Bowen	Condabri	CSG	230	0.26	4.32	7.47
Surat–Bowen	Spring Gully & Fairview	CSG	125	0.26	4.32	7.47
Surat–Bowen	AP Woleebee & Gooimbah	CSG	96	0.26	4.32	7.47
Surat–Bowen	Ironbark	CSG	0	0.26	4.32	7.47
Surat–Bowen	Kenya & Kogan	CSG	162	0.26	4.32	7.47
Surat–Bowen	Jordan, QC Woleebee & Ruby	CSG	0	0.26	4.32	7.47
Sydney	Sydney	CSG	9	0.26	4.32	7.47
Sydney	Hunter area	CSG	0	0.26	4.32	7.47

a Sourced from AEMO (2014b). **b** Variable costs of CSG processing from MMA (2009); conventional and shale gas processing from McDonough (1997), updated to 2014-15 dollars using a gross domestic product deflator (ABS 2014). **c** Data sourced from Core Energy Group (2012a). Where data are not available for expansion or construction of a specific processing plant, data for comparable processing facilities (CSG or conventional processing, as appropriate) are used.

Sources: ABS (2014); AEMO (2013a, 2014b); Core Energy Group (2012a); McDonough (1997); MMA (2009).

Transmission pipelines

For each transmission pipeline, data have been collected on system use of gas,[12] lifetime, build time, the extent to which existing pipelines can be expanded (expansion limits), investment cost, length and capacity. These parameters are all relevant to determining pipeline usage, operating and investment costs.

System use of gas varies across pipelines and depends primarily on the amount of compression installed on a pipeline, which in turn depends on the amount of gas flow and the distance it is required to flow (IEA 2007). However, pipeline-specific data on system use of gas are not publically available so a generic estimate of system use of gas has been applied for all pipelines. Generic estimates of lifetime and build time are also applied across all pipelines (table B.5).

Expansion limits, investment cost, length and capacity of pipelines have been estimated for each pipeline route in the model, as explained in the following sections.

Table B.5 **Transmission inputs**
Applied to all pipelines

Input	*Estimate*	*Sources*
System use of gas	1.1 per cent of gas transported	DRET (2013) examined system use of gas for 24 pipelines and found a volume-weighted average of 1.1 per cent. Eight of 24 pipelines had system use of gas greater than 1 per cent and five of these pipelines had system use of gas greater than 1.5 per cent.
Pipeline expansion build time	2 years	Based on an average of historical and forecast build times for pipeline expansions (APA Group 2011b, 2012a; Jemena nd; The Australian Pipeliner 2009, 2013).
New pipeline build time	3 years	Based on an average of historical and forecast pipeline build times (APIA 2011; APLNG 2012b; Jemena 2015b; Santos nd; The Australian Pipeliner 2006, 2012).
Pipeline lifetime[a]	60 years	Based on estimates of pipeline lifetime (AER 2012b; APA Group 2011a; Arrow Energy 2011; Australian Pipeline Trust 2003; DRET 2013; Frontier Economics 2010; Jemena 2015b; Santos nd).

[a] The same lifetime estimates are used for new pipelines and expansions to existing pipelines.

[12] System use of gas is the difference between gas received into a pipeline and gas delivered to users. System use of gas is comprised of gas that is used for transmission and gas that is unaccounted for, which is comprised of metering errors, unmeasured gas use and fugitive emissions. The vast majority (between 80 and 90 per cent) of system use of gas is gas used in driving compressors (DRET 2013).

Expansion limits

'Brownfield' and 'greenfield' expansion of pipeline capacity are allowed. Brownfield investment refers to expansions of capacity through compression and/or looping, which is likely to be lower cost than larger expansions or building a new pipeline (collectively referred to as greenfield expansions)[13] unless a very large expansion of capacity is required. Limits are placed on brownfield expansion of existing pipelines as there are limits to the extent to which expansion of capacity is physically feasible and economical, through compression in particular. Brownfield expansions are limited to a tripling of existing pipeline capacity for all pipelines (table B.6). The brownfield expansion limit applies to cumulative expansion over the simulation period, which can occur over multiple years.

Once the limit on brownfield expansion is reached, greenfield expansion can follow for selected routes. There is a limit of one new pipeline per route. Brownfield expansion on new pipelines is not considered in modelling.

Table B.6 **Expansion limits**
Applied to all pipelines

Input	*Estimate*	*Sources*
Brownfield expansion limit	Current capacity can be expanded by up to 200 per cent.	Most recent expansion projects have increased (or proposed to increase) capacity between 10 and 100 per cent. However, many pipelines have been expanded multiple times over their lifetime, increasing capacity by up to or more than 200 per cent. For example, capacity on the RBP has increased more than fivefold since the 1960s (The Australian Pipeliner 2012a). Details of recent expansion projects are outlined in table B.9.
Greenfield expansion limit[a]	One new pipeline per route during the simulation period.	

[a] Greenfield expansion is restricted to pipeline routes where greenfield expansion is likely to be an economic option — the Surat–Bowen to Gladstone route, the Gunnedah to Young route and the Clarence–Morton to Brisbane route. These routes were chosen because testing suggested that new pipelines are unlikely to be economic on other routes. Including redundant options requires increasing the number of binary variables, which increases the time taken to solve the model.

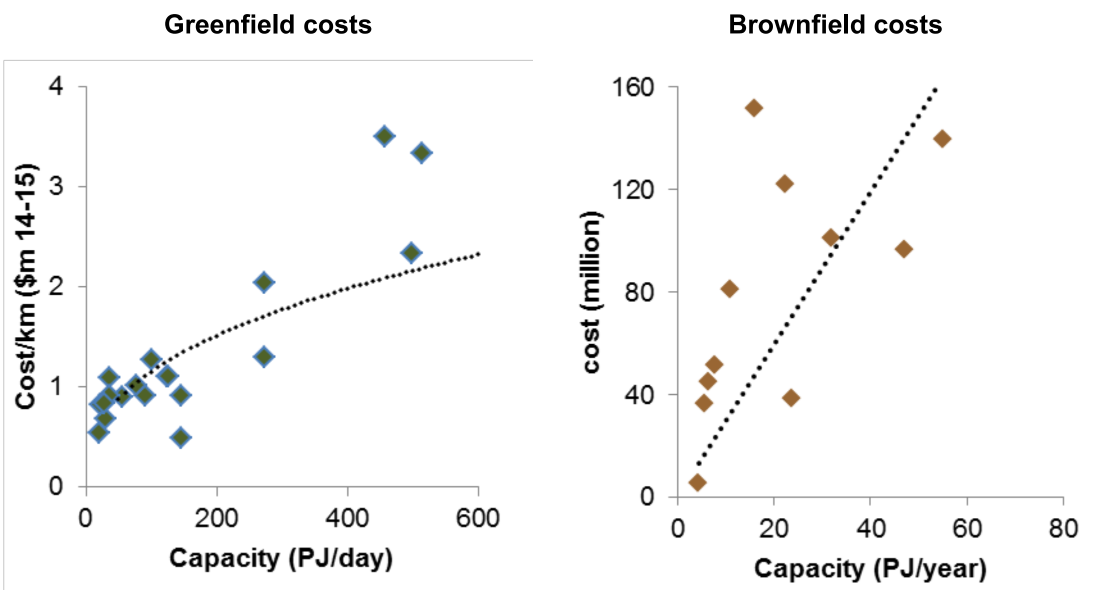
[13] Greenfield expansion can occur along a route that has an existing pipeline or along a route that does not have a pipeline.

Investment cost

The cost of building a pipeline consists of right of way costs, material used (which affects friction), the amount of compression installed, engineering and overhead costs and other installation-related costs (IEA 1994; Yepez 2008). These costs are a function of a pipeline's length and its capacity (which depends principally on its diameter). Pipeline construction costs can exhibit increasing returns to scale, as pipeline capacity depends on the pipeline's interior cross-sectional area, which is proportional to the square of its diameter. However, there are limits to increasing returns to scale determined by pressure differentials, the length of a pipeline and other factors (Kahn 1988).

Greenfield investment costs were estimated using data for a selection of recently built or proposed pipelines (table B.7). A functional form incorporating increasing returns to scale was used, based on DRET (2013). To implement greenfield investment in the model, two sizes of pipelines can be built. Cost estimates are based on the Commission's regression results (reported in figure B.4).

Figure B.4 **Brownfield and greenfield investment costs**



$cost/km = \alpha_1 capacity^{\alpha_2}$ **a** $\qquad$ $cost = \beta_1 capacity$ **b**

a DRET (2013) noted that the cost per km of building a pipeline is proportional to capacity to the power of 0.24 (cost/km α capacity$^{0.24}$). This functional form was generalised by the Commission in the form: $cost/km = \alpha_1 capacity^{\alpha_2}$. Using a logarithmic transformation, an ordinary least squares regression was used to estimate parameters: α_1 was estimated to be $0.19 million per km and α_2 was estimated to be 0.39 (higher than DRET's estimates). The higher estimate for α_2 is consistent with limits to economies of scale. **b** β_1 was estimated to be $2.97 million dollars per PJ per year.

Data source: Commission estimates based on tables B.8 and B.9.

Table B.7 **Greenfield investment costs**

Pipeline capacity	*Cost per km ($m)*[a]
100 PJ/year	1.15
300 PJ/year	1.76

[a] Costs per km have been estimated using regression results.

Source: Commission estimates.

Brownfield investment costs were estimated based on infrastructure projects since 1999 where pipeline capacity has been expanded through looping and/or compression (table B.9). Length is likely to be a less important factor in the cost of brownfield relative to greenfield investments, particularly when additional capacity is added through compression.[14] Length was tested as an explanatory variable in a regression of cost as a function of capacity but was not found to have a statistically significant effect on expansion costs. There may be increasing returns to scale in brownfield expansion but there are likely to be limits beyond which there will be *decreasing* returns to scale, particularly where expansion is through compression. Therefore a linear ordinary least squares regression of cost on capacity was used (figure B.4). Regression results suggest that, on average, an additional unit of capacity (1 PJ per year) costs just under $3 million.

Transmission investment costs have also been adjusted in the model for the useful life of assets outside the simulation period (box B.3).

[14] The costs of building a new pipeline increase with each additional kilometre of length due to higher material, right of way and other costs. More compression will likely be required on longer pipelines to increase capacity by a given amount. However, compressor stations are typically spaced more than 100 km apart along a pipeline so it is unlikely that the costs of compression will increase with each additional kilometre of length. Large fixed costs of compressor stations also suggest the relationship between the cost of expansion through compression and length is weak.

Table B.8 **Recent greenfield expansion projects**

Pipeline	*Year*[a]	*Length (km)*	*Capacity*[b] *(PJ/year)*	*Capital*[c] *cost ($m)*	*Type of cost*	*Sources*
APLNG	2014	362	456	1 266	Predicted	(Core Energy Group 2012b)
Arrow Bowen	na	600	272	1 222	Predicted	(Core Energy Group 2012b)
Arrow Surat	na	470	272	608	Predicted	(Core Energy Group 2012b)
Blackwater	na	257	100	325	Predicted	(Core Energy Group 2012b)
Bonaparte	2008	287	29	197	Ex post	(AER 2010)
Central Qld	na	440	35	481	Predicted	(Core Energy Group 2012b)
Coolah to Newcastle	na	280	146	255	Predicted	(Core Energy Group 2012b)
EGP	2000	797	55	714	Ex post	(AER 2008; Jemena 2015a; LECG Economics and Finance 2000)
GLNG	2014	435	498	1 013	Predicted	(Core Energy Group 2012b)
Gloucester to Hexham	na	98	22	81	Predicted	(BREE 2014e)
Great Northern (Broome to Pt Hedland)	na	550	90	500	Predicted	(BREE 2014e)
Ironbark	na	440	35	401	Predicted	(Core Energy Group 2012b)
Lions Way	na	145	27	122	Predicted	(Core Energy Group 2012b)
North Queensland Gas Pipeline	2005	369	20	200	Ex post	(AER 2007)
QCLNG	2013	334	515	1 114	Predicted	(Core Energy Group 2012b)
Qld Hunter	na	825	124	911	Predicted	(BREE 2012; Core Energy Group 2012b)
QSN Link	2009	180	77	182	Ex post	(AER 2011b)
SGP	2003	660	125	727	Ex post	(AER 2007)
Wallumbilla to Darling	2009	205	146	99	Ex post	(AER 2009)

[a] Some projects are either yet to be completed, construction has not begun or are proposed. [b] Capacity when the pipeline was built. Some of these pipelines have been expanded since they were built. [c] For projects completed prior to 2014-15, nominal project costs have been inflated using the GDP deflator (ABS 2015).

Table B.9 **Recent brownfield expansion projects**

Pipeline	*Year*[a]	*Type of expansion*	*Capital*[b] *cost ($m)*	*Capacity increase (PJ/year)*	*Sources*
Canberra Lateral	1999	Looping	5.6	4.4	(NCC 2002)
Carpentaria	2009	1 compressor	36.3	5.6	(AER 2010; APA Group 2009)
Corio loop	2008	57 km of looping	81.0	11.0	(AER 2008; VENCORP 2005)
EGP	2000	7 compressor units at 4 stations	139.6	55.0	(NCC 2000)
EGP	2010	1 compressor	44.8	6.6	(AER 2010)
Goldfields	2012	4 compressors	151.5	16.1	(APA Group 2012a)
MSP	2000	Not specified	96.8	47.0	(NCC 2000)
MSP	2012	Not specified	101.0	32.0	(Core Energy Group 2012b)
QGP	2010	Not specified	122.3	22.3	(AER 2010)
RBP	2011	6 km loop and 1 compressor	51.4	7.7	(Core Energy Group 2012b)
SWP[c]	..	1 compressor	38.6	23.7	(APA Group 2012b)

[a] Year completed. [b] For projects completed prior to 2014-15, nominal project costs have been inflated using the GDP deflator (ABS 2015). [c] For the SWP, an average cost and average capacity increase was used for six expansion projects submitted to the Australian Energy Regulator for approval. **..** Not applicable.

Length and capacity of pipelines

Length and capacity of pipelines were sourced from AEMO, Core Energy Group and pipeline owners (table B.10), including both standard (normal flow direction) and reverse capacities for bidirectional pipelines. The NVI, MAPS, SWP and SWQP are either bidirectional or will soon be made bidirectional. These pipelines have or will have a smaller capacity in the reverse than standard direction (AEMO 2013b, 2013c; Epic Energy, pers. comm., 27 January 2015). The RBP and MSP are also bidirectional or will soon be made bidirectional (APA Group, pers. comm., 4 December 2014) but information on reverse capacity is not publicly available, so reverse capacity has been set to equal standard capacity. The Young to Gunnedah route is also set to be bidirectional despite the existing pipelines along this route (the CRP and CWP) being unidirectional (gas flows from Young to Gunnedah). This is because flows will likely be in the opposite direction (from Gunnedah to Young) if the Gunnedah gas basin is developed (Santos 2014b). Reverse capacities have been incorporated in modelling so that reverse flows can be made available if economic.

As noted above, a 200 per cent limit is placed on brownfield expansions. For bidirectional pipelines, standard and reverse capacity are assumed to increase in unison, so that capacity increases for reverse flow can exceed 200 per cent.

Box B.3 Truncation of investment cost data for transmission and storage assets

Transmission and storage assets have long economic lifetimes that are likely to continue beyond the 40 year simulation period. In such cases it is inappropriate to attribute all of the investment cost to the simulation period being modelled.

Ideally, the full costs and benefits of all investments would be contained in the simulation period. However, a longer simulation period involves computational costs and, for assets with multiple period lifetimes that are commissioned toward the end of any finite modelling timeframe, some use will occur beyond the simulation period. Any formula truncating investment costs must make assumptions about the allocation of the investment costs between the simulation period of the model and beyond the simulation period. In the model, this truncation is done on a pro rata basis: the share of the asset's economic life that is beyond the simulation period is subtracted from the total investment cost. This presupposes that the cost of investment is evenly amortised over time. An example of how transmission and storage investment costs are truncated in the model is shown in the table below.

Example: truncation of investment costs

Asset with a 10 year lifetime and a 2 year build time, in a 10 year simulation with investment in year 1

Year	*Investment cost ($)*	*Amortisation of investment cost ($)*	*Discount factor*	*Discounted amortisation of investment costs ($)*
1	100		1.00	0.00
2			0.94	0.00
3		14.40	0.89	12.82
4		14.40	0.84	12.09
5		14.40	0.79	11.41
6		14.40	0.75	10.76
7		14.40	0.70	10.15
8		14.40	0.67	9.58
9		14.40	0.63	9.04
10		14.40	0.59	8.52
11		14.40	0.56	8.04
12		14.40	0.53	7.59
Total investment cost	100			100.00
Truncated investment cost years 1 to 10				84.37

Source: Based on PC (2011).

Table B.10 **Transmission pipeline length and capacity**

Node A	*Node B*	*Related pipe/s*	*Length*[d] *(km)*	*Capacity*[g] *(PJ/year)*		*Sources*
				Std	*Rev*	
Clarence-Morton	Brisbane	Proposed Lions Way Pipeline	145	0	**na**	Core Energy Group (2012b)
Cooper	Adelaide	MAPS	858	92	51[h]	Core Energy Group (2012b); Epic Energy (2015; pers. comm. 26 January 2015)
Cooper	Mt Isa[a]	CGP	840	43	**na**	AEMO (2013b)
Cooper	Young	MSP	1 000[e]	160	160	AEMO (2013b)
Gippsland	Melbourne	LMP	174	376	**na**	Core Energy Group (2012b)
Gippsland	Sydney	EGP	797	106	**na**	AEMO (2013b; Jemena (2015a)
Gippsland	Tasmania	TGP	734	47	**na**	AEMO (2013b); AER (2013a)
Otway	Adelaide	SEA	680	115	**na**	AEMO (2013b); AER (2013a)
Otway	Melbourne	SWP	208[f]	129	47	AEMO (2013b)
Surat–Bowen	Brisbane	RBP	438	80	80	Core Energy Group (2012b)
Surat–Bowen	Cooper[a]	SWQP/QSN	937	141	124	APA Group (2015)
Surat–Bowen	Gladstone	QGP and[c] LNG pipelines	514	1 654	**na**	AEMO (2013a); IES (2013)
Young	Gunnedah[b]	CWP and CRP	555	5	**na**	AER (2013a); APA Group (pers. comm. 17 February 2015)
Young	Melbourne[c]	NVI	523	44	26	AEMO (2013b, 2013e)
Young	Sydney	MSP	300[d]	160	160	AEMO (2013b)

a The Carpentaria Gas Pipeline connects to the Cooper basin through the QSN Link but is modelled as connecting directly to the Cooper basin. To account for this, the sum of flows along the CGP and the SWQP/QSN are constrained in the model to equal the capacity of the SWQP/QSN. **b** The length of this route has been estimated based on the length of a number of pipelines. **c** On this route, length is based on the QGP and capacity is based on the sum of the capacities of the QGP and announced capacity for the APLNG, GLNG and QCLNG pipelines. **d** Length estimates are for mainlines and exclude laterals. **e** The MSP is 1300 km. The length of the Cooper to Young route has been set to be 1000 km and the Young to Sydney route has been set to be 300 km. It has been estimated that it is 1000 km from Moomba to Young and 300 km from Young to Sydney. **f** Length along this route is the sum of the length of the SWP (150 km) and the Brooklyn to Lara Pipeline (58 km). The Victorian Gas Planning Report noted that by winter 2015 the capacity of the SWP will be increased to 157 PJ per year in the standard flow direction (AEMO 2013e). This increase is not incorporated into the model. **g** Both standard (std) and reverse (rev) capacity are considered in modelling since some but not all pipelines are bidirectional. **h** Requires some brownfield expansion to achieve this capacity. **na** Not applicable.

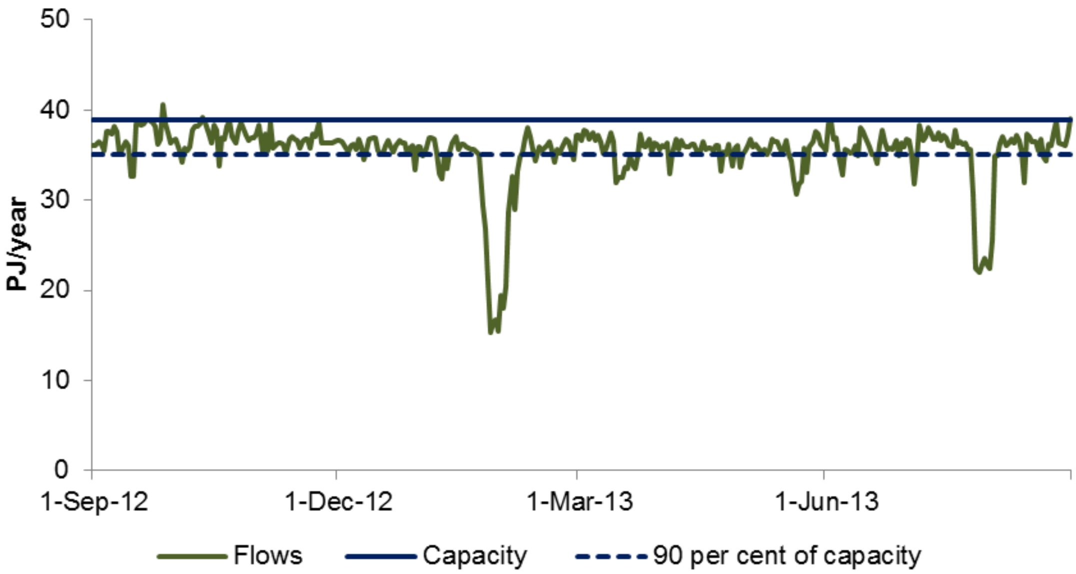
Maximum average capacity utilisation

Demand for gas fluctuates during each year. Some gas users, such as industrial users, have fairly steady demand over the year while demand by other users exhibits daily or seasonal fluctuations. In winter, demand for gas for heating is higher in cooler climates, particularly on very cold days. In summer, demand for gas is high on very hot days when gas powered generation is used to meet higher electricity demand due to greater use of air conditioning. Peak demand is taken into consideration when pipelines are built and compressions stations are added. Typically, they do not operate at their maximum or nameplate capacity every day.

Flow data from the National Gas Bulletin Board from September 2012 to August 2013[15] indicate that the QGP had the highest capacity utilisation of any transmission pipeline in the eastern Australian gas market. While capacity utilisation on the QGP reached 100 per cent at times, its average capacity utilisation was close to 90 per cent (figure B.5). It is unlikely that other less utilised pipelines would operate at greater than 90 per cent of their nameplate capacity on average if demand was higher. A common maximum average capacity utilisation of 90 per cent of nameplate capacity has been applied to all pipelines for both the summer and winter seasons in the model.

Figure B.5 **Queensland Gas Pipeline**

Daily flows and capacity



Source: National Gas Bulletin Board.

15 Data from September 2012 to August 2013 were examined because this is the first year in the model.

Storage

Storage facilities are used by producers, pipeline companies and distribution networks to avoid imbalances between receipts and deliveries (and consequent rationing), to manage inventory and to manage inter-seasonal demand fluctuations. Where available, gas storage can offer a lower cost alternative to increasing production and processing capacity to meet peak demand. Storage will be economical for gas suppliers where the difference between peak and off-peak prices exceed the cost of storage.

Data have been collected on the marginal cost (for both injecting and withdrawing gas), build time and lifetime of gas storage facilities. Estimates of the costs of expanding or building new storage facilities are also included in the model. Generic cost estimates are applied to all storage facilities due to limited data (table B.11). The lack of data has also meant that assumptions have been made for some parameters based on feedback from industry stakeholders. Large underground storage facilities are included (table B.12) but LNG storage facilities are excluded because they are usually much smaller and more expensive to build and operate (per unit of storage capacity)[16] so are not typically used for inter-seasonal storage and only used for short-term storage.

Table B.11 **Storage inputs**
Applied to all storage facilities

Input	*Units*	*Estimate*	*Source*
Marginal cost of injection	$/GJ	0.125	System use of gas accounts for the majority of the marginal cost of storage. The total marginal cost of injecting into and withdrawing from storage has been set at $0.25 per GJ based on system use of gas of between 2 and 3 per cent. This cost has been split equally between injection and withdrawal.
Marginal cost of withdrawal	$/GJ	0.125	
Build time	Years	2	Midpoint of build times for recent projects.
Lifetime	years	100	Underground storage facilities are likely to have long economic lifetimes.
Building/expansion costs[a]	$/GJ	12.5	Based on expansion of the Mondarra Storage Facility costing $150 million to expand capacity by 12 000 000 GJ (The Australian Pipeliner 2011).

[a] Expansion of storage facilities is only allowed at nodes that already have underground storage facilities.

[16] For example, the Newcastle gas storage facility under construction will have a capacity of 1.5 PJ. The estimated capital cost of the project is $300 million (AGL Energy 2015b).

Table B.12 **Storage facilities**

Model node	*Facility*	*Capacity (PJ)*	*Source*
Brisbane	Newstead Underground	2	AEMO (2013b)
Cooper	Ballera Underground	13.7	AEMO (2013b)
Cooper	Moomba Underground	85	AEMO (2013b)
Otway	Iona Underground	22	AEMO (2013b)
Surat–Bowen	Roma Underground	50	Santos (2014b)
Surat–Bowen	Silver Springs	30	Fraser (2013)

LNG conversion and export demand

Demand for gas to supply LNG exports is modelled in two parts: existing LNG contracts (and associated liquefaction plant capacity) and the potential for further increases in LNG exports.

Existing LNG contracts

Almost all of the LNG capacity currently under construction in Gladstone is contracted for 20 years or more (table B.13).[17] The assumption used for modelling is that LNG producers must deliver this 'already-contracted' quantity, independent of conditions in the Asia–Pacific LNG market (figure B.6).

This assumes that contracts are binding and cannot be terminated, and that contract volumes are not renegotiated, regardless of the price of LNG in the Asia–Pacific market. Existing LNG contracts for export of gas are explicitly represented in this way because contracts are likely to have penalty clauses associated with any failure to export gas from Australia.

This approach does not take into account any 'downward quantity tolerance' clauses in LNG contracts. A downward quantity tolerance clause allows a buyer to purchase less than the fully contracted amount in a given year without incurring sanctions (Gas Strategies 2015). If this were to occur, LNG plants could reduce production. However, as LNG plant costs have already been sunk, the decision of whether to continue to sell excess LNG on spot markets would be based on the short-run marginal cost of supply export markets, so it is possible that the quantity of gas produced from LNG plants could remain unchanged.

[17] APLNG and QCLNG contracts cover slightly less than their full 'nameplate' capacity, but the true operating capacity of LNG plants tends to be less than nameplate capacity due to downtime for maintenance (Core Energy Group 2013b).

Table B.13 **LNG contracts**

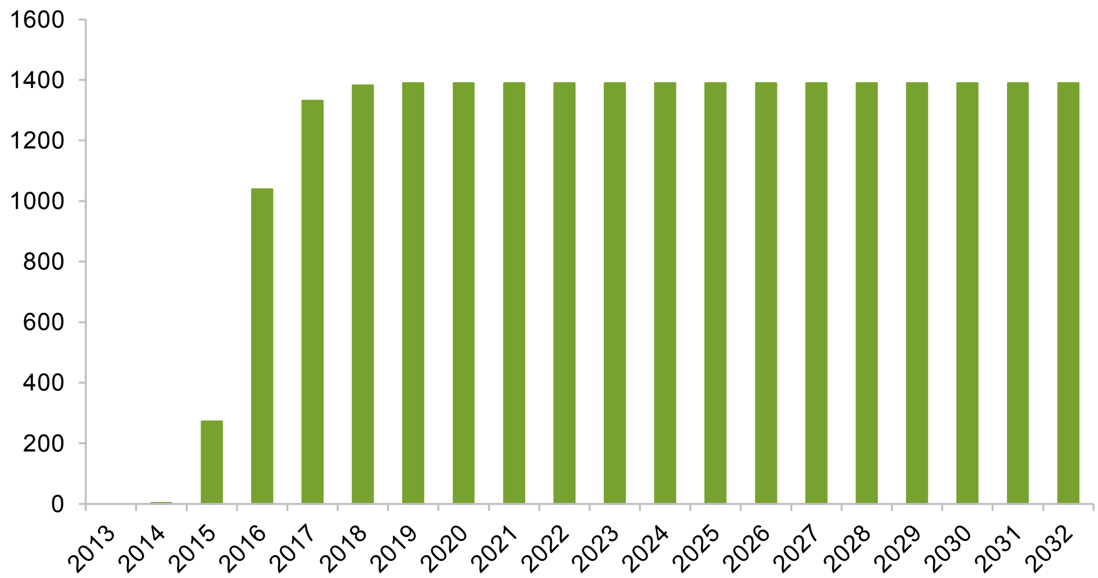
Seller	*Buyer*	Volume (million tonnes per annum)	Volume (PJ/yr)[a]	Time period (years)
Australia Pacific LNG	Kansai Electric	1.0	54.4	20
Australia Pacific LNG	Sinopec	7.6	413.4	20
Gladstone LNG	KOGAS	3.5	195.8	15+5[b]
Gladstone LNG	PETRONAS	3.7	195.8	20
Queensland Curtis LNG	Chubu Electric	0.4[c]	21.8	21
Queensland Curtis LNG	CNOOC	3.6	195.8	20
Queensland Curtis LNG[d]	CNOOC	5.0	272.0	20
Queensland Curtis LNG	Tokyo Gas	1.2	65.3	20

[a] Based on a conversion rate of 1 million tonnes = 54.4 PJ (BREE 2014c). [b] Agreement is binding for 15 years with Gladstone LNG having the option to extend the agreement for a further 5 year period. [c] Agreement is for up to 122 cargoes over 21 years which is equivalent to 0.4 mtpa if a 70 000 ton capacity vessel is used. [d] To be sourced from BG Group's global portfolio of LNG plants, not exclusively from Queensland Curtis LNG.

Sources: APLNG (2012a); BG Group (2010, 2011a, 2011b, 2013); GIIGNL (2012); Santos (2010, 2013b).

Figure B.6 **Gas demand for already-contracted LNG**[a]

Petajoules



[a] Includes gas used during the liquefaction process but does not include gas use and losses related to transmission, production and processing. These losses are accounted for separately.

Source: Commission estimates based on Jacobs SKM (2014b).

Further increases in LNG exports

Further increases in LNG exports require either building additional trains at existing liquefaction plants (brownfield investment) or building whole new plants (greenfield investment).[18] Recent reports suggest additional greenfield investments are unlikely — particularly given Shell's decision to cancel the Arrow Energy LNG project — but investment prospects could change over the next 20 years (Ledesma, Henderson and Palmer 2014; Macdonald-Smith 2015). The possibility of both further brownfield investment and further greenfield investment is allowed for the in the model.

Constraints are placed on the maximum cumulative investment (across all years modelled) in brownfield LNG plant investment, but no constraints are placed on greenfield LNG investment (table B.14).

Table B.14 **LNG investment limits**

	Maximum cumulative investment (PJ per year of capacity)	
	Nameplate capacity (mtpa)	*Implied gas demand (PJ)*
Brownfield	14.7[a]	810[b]
Greenfield	No limit	No limit

[a] Based on the total capacity of additional trains proposed (but not committed) by the Australia Pacific LNG, Gladstone LNG and Queensland Curtis LNG plants (AER 2013a; IEA 2014). [b] Based on a conversion rate of 1 million tonnes = 54.4 PJ (BREE 2014c) and after accounting for gas used as fuel during the liquefaction process.

Sources: AER (2013a); BREE (2014c); IEA (2014).

Investment in further LNG capacity will depend on liquefaction plant costs and LNG export demand in the Asia–Pacific market.

Liquefaction plant costs

The capital cost of greenfield plant capacity in the model is based on recent estimates for the Australia Pacific LNG plant, the Gladstone LNG plant and the Queensland Curtis LNG plant. Estimates for each plant were obtained from BREE (2014d) and the Oxford Institute of Energy Studies (2014). The average of these six estimates is used in the model

[18] It may also be possible to achieve small increases in the capacity of existing trains (in the order of 5–10 per cent) through 'debottlenecking'. Plant debottlenecking involves upgrading or modifying key equipment, such as compressors and turbines, that limit production. Identifying debottlenecking opportunities requires operating experience and potential capacity increases tend to be smaller in more recently designed plants (Tusiani and Shearer 2007). Given the cost and potential for debottlenecking of the Gladstone plants is uncertain, this possibility is not included.

(table B.15). These estimates are then adjusted for higher required rates of return than the discount rate in the model, as discussed in box B.2.

The capital cost of brownfield plant capacity is estimated to be two thirds of the cost of greenfield plant capacity, in line with analysis by the Oxford Institute of Energy Studies (2014).

Table B.15 **Liquefaction plant capital costs**
$ per GJ of annual capacity

	Unadjusted capital cost	*Certainty-equivalent capital cost*
Greenfield	23	51
Brownfield	15	32

Source: Commission estimates.

Operating costs are split into two components: own-use of gas and general operating and maintenance expenditure. Both vary according to liquefaction plant output.

- Nine per cent of input gas is used as fuel during the liquefaction process based on estimates from Core Energy Group (but excluding transmission losses and gas use in production and processing) (2013b).
- General operating and maintenance expenditure is estimated to be $0.70 per GJ of input gas (3 per cent of capital expenditure, based on White and Morgan (2012)).

From the time an investment decision is made to the commencement of LNG production, it takes four years to build a new liquefaction plant and three years to expand an existing liquefaction plant in the model. These estimates are based on the experience of recent plant constructions in Australia (APLNG 2014; BG Group 2014a; Santos 2011a; Woodside 2013). The economic lifetime of a liquefaction plant in the model is 40 years (BG Group 2014b). The earliest model period when a decision to invest in new liquefaction plant capacity can be made is 2015-16.

LNG export demand

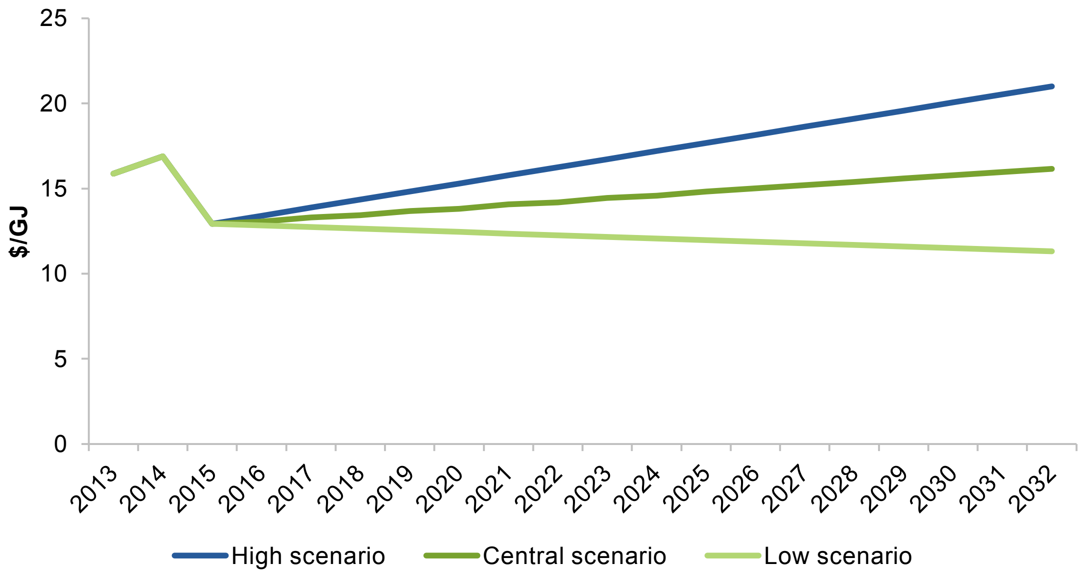
LNG export demand is an important factor in future market outcomes in the eastern Australian gas market. While demand for gas from existing LNG facilities is treated as fixed, future LNG export demand will influence whether existing facilities are expanded or new facilities built. In turn, expansions in exports would affect prices for natural gas in the eastern Australian gas market.

Demand for LNG exports from the eastern Australian gas market is assumed to be perfectly elastic. This implies that additional exports from the eastern Australian gas market would have no effect on LNG prices in the Asia–Pacific market. LNG export demand can therefore be represented by a fixed price series for future Asia–Pacific LNG prices.

The outlook for LNG export prices is uncertain. Future prices in the Asia–Pacific market will depend on factors such as the price and availability of substitute fuels, the rate of growth in demand from China, and the timing and scale of new supply from Russia and the United States (Bradshaw et al. 2013; BREE 2014d). Reflecting this uncertainty, three scenarios have been developed for LNG export prices: high, central and low.

The central scenario uses a price series derived from the latest forecast of Japanese LNG import prices produced by the World Bank (2015b). A freight cost of US$0.81 per GJ is subtracted from the forecast to estimate a 'free on board' export price (Platts 2015). Prices are converted to Australian dollars using historical exchange rates for past years and a rate of A$1.00 = US$0.80 for future years. The high and low scenarios diverge from the World Bank forecast linearly so that, by 2032, the high scenario price is one third higher, and the low scenario price is one third lower than the central scenario price (figure B.7).

Figure B.7 **LNG export price series**[a]



a Free on board prices.

Source: Commission estimates based on World Bank (2015b).

Domestic demand for gas

The domestic demand function for each season and year at each demand node in the eastern Australian gas market depends on the following parameters:

- wholesale prices in the initial model year
- wholesale quantity demanded in the initial model year
- the price elasticity of demand and functional form for demand
- rates of growth in domestic demand over time.

Wholesale gas prices

Wholesale gas prices for each season in the initial model year were used to calibrate domestic demand functions (table B.16). At the four demand nodes with active wholesale trading markets (Adelaide, Brisbane, Sydney and Melbourne) an average of daily prices for each season from AEMO (2014e, 2014f) was used. Because wholesale prices on the Victorian Declared Wholesale Gas Market (DWGM) do not include transmission costs, an average DWGM tariff obtained from AEMO (pers. comm., 30 October 2014) was added to the Melbourne wholesale gas price.

At nodes without wholesale trading markets, gas prices are estimated by taking trading market prices and adding or subtracting transmission tariffs according to the direction of gas flows. For example, the price at the Surat–Bowen node was estimated by subtracting the Roma-Brisbane Pipeline tariff from the Brisbane price. Transmission tariffs were obtained from AEMO (2013b), AER (2012c) and Core Energy Group (2012b).

Table B.16 **Domestic wholesale gas prices**

$ per GJ

Model node	*Winter*	*Summer*
Adelaide	5.38	4.82
Brisbane	5.85	5.98
Gladstone	6.24	6.38
Melbourne	5.08	5.00
Mt Isa	5.82	5.95
Otway	4.64	4.08
Surat–Bowen	5.33	5.47
Sydney	5.23	4.83
Tasmania	5.82	5.74
Young	5.86	5.79

Sources: Commission estimates based on AEMO (2013a, 2014e, 2014f); AER (2012b) and Core Energy Group (2012b).

At a given demand node in a given season, it is assumed that all users pay the same price for gas. This is because there is no explicit representation of contracts or price discrimination. There are two reasons why contracts are not represented. First, prices reflect the demand for gas *at the margin*. Short term trading markets provide the best indicator of marginal prices.

Second, contracts do not necessarily determine where gas will ultimately be used. Contracted gas can potentially be on-sold to other users through secondary markets so that gas still flows to the highest value use (subject to infrastructure and contracting constraints). For example, under higher gas prices an industrial firm with a contract for gas supply might choose to reduce gas consumption (for example, by switching to alternative fuel sources) and on-sell their contracted gas to the highest bidder. Short term price changes for users seeking gas could be greater if contract conditions preclude gas from being on-sold, which would need to be accounted for to forecast short-term price changes.

Wholesale gas demand

Quantities of wholesale gas demanded in the initial model year are also required to calibrate demand functions. There is demand at each node for three groups: gas-powered electricity generators, industrial users, and mass market (residential and commercial) users. Demand from each group (table B.17) was estimated based on historical daily electricity generation data and gas demand trace data provided by AEMO (2013d; unpublished data, 2014).

Table B.17 **Domestic wholesale gas demand**
Total quantity demanded (PJ)

	Electricity generation		*Industrial*		*Mass market*	
Model node	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*
Adelaide	16	43	7	19	3	8
Brisbane	3	8	11	31	0	1
Gladstone	3	10	12	35	1	1
Melbourne	1	2	28	46	42	69
Mt Isa	0	0	9	26	0	1
Otway	3	12	1	1	1	2
Surat–Bowen	12	39	2	7	0	0
Sydney	8	24	16	34	11	23
Tasmania	1	7	1	4	0	1
Young	1	3	4	9	3	6

Source: Commission estimates.

Price elasticity of demand

For mass market demand and industrial demand, separate estimates of the price elasticity of demand have been sourced for each state from AEMO's National Gas Forecasting Report (table B.18). For electricity generation demand, a single elasticity estimate of -0.7 was used (Wagner 2014). For industrial use and electricity generation in particular, demand responses to price increases are likely to be more discrete (or 'lumpy') than suggested by a smooth demand function, as particular large users might cease using gas altogether above a certain price. Using a single elasticity estimate is a simplification that reflects a lack of data about the price points that will cause particular users to cease using gas, and is consistent with averaging discrete demand changes across multiple users.[19]

Table B.18 **Price elasticity of industrial and mass market demand**

Model node	*State*	*Elasticity*	
		Mass market	*Industrial*
Adelaide	South Australia	-0.61	-0.50[a]
Brisbane	Queensland	-0.40	-0.65
Gladstone	Queensland	-0.40	-0.65
Melbourne	Victoria	-0.18	-0.41
Mt Isa	Queensland	-0.40	-0.65
Otway	Victoria	-0.18	-0.41
Surat–Bowen	Queensland	-0.40	-0.65
Sydney	New South Wales	-0.34	-0.44
Tasmania	Tasmania	-0.20	-0.50[a]
Young	New South Wales	-0.34	-0.44

[a] Commission estimates, based on average of industrial demand elasticity in other states.

Source: AEMO (2014c).

Demand growth

Demand projections were estimated using data from AEMO's 2014 national gas forecasting report (AEMO 2014d). For calibration of demand functions, movements along each demand function (the effect of price changes) need to be distinguished from shifts in that demand function. Movements along the demand function are captured by the demand function itself and should not be incorporated in data used for calibration. Data from the national gas forecasting report were adjusted to remove the effect of price changes on demand forecasts using demand elasticities and price estimates documented as part of the national gas forecasting report (AEMO 2014c). The national gas forecasting report

[19] The demand function used is a linear approximation of a constant elasticity of demand function (box B.1). However, the linearisation approach does mean that there is some lumpiness to changes in demand.

forecasts prices until 2034, so annual proportional demand changes between 2013 and 2034 were extrapolated to estimate demand growth after 2034.

For many locations and uses of gas — in particular, gas-fired generation — demand is projected to decrease to 2020 but increase thereafter (table B.19). These growth rates are used to determine how demand functions shift over time. In the framework applied in this project, prices and quantities are endogenous and so outcomes for prices and quantities are different to those used to calibrate the demand functions.

Table B.19 **Demand growth**

Model node	*Demand type*	*Demand growth 2013–2020 (per cent)*	*Demand growth 2013–2032 (per cent)*
Adelaide	Generation	-47	30
Adelaide	Industrial	1	7
Adelaide	Household and commercial	18	42
Brisbane	Generation	-44	17
Brisbane	Industrial	10	39
Brisbane	Household and commercial	18	43
Gladstone	Generation	-44	17
Gladstone	Industrial	10	39
Gladstone	Household and commercial	18	43
Melbourne	Generation	-59	32
Melbourne	Industrial	-3	25
Melbourne	Household and commercial	10	29
Mt Isa	Generation	-44	17
Mt Isa	Industrial	10	39
Mt Isa	Household and commercial	18	43
Otway	Generation	-59	32
Otway	Industrial	-3	25
Otway	Household and commercial	10	29
Surat–Bowen	Generation	-44	17
Surat–Bowen	Industrial	10	39
Surat–Bowen	Household and commercial	18	43
Sydney	Generation	-25	14
Sydney	Industrial	-5	5
Sydney	Household and commercial	23	54
Tasmania	Generation	-81	-42
Tasmania	Industrial	13	-6
Tasmania	Household and commercial	47	86
Young	Generation	-25	14
Young	Industrial	-5	5
Young	Household and commercial	23	54

Source: Commission estimates.

B.3 Potential extensions to the model

The priority in developing the model has been to keep it as simple as practicable to achieve policy insights, facilitating transparency in the modelling approach and use of data. Several extensions are possible that might yield further insights.

- A more detailed description of well production profiles and well deliverability constraints, in particular for CSG production.
- Explicitly modelling of 3P and 2C resources, which can be produced at a higher cost to 2P reserves.
- More complex expectations mechanisms for including risk for gas market participants.
- Oligopolistic behaviour among gas producers, processors and/or transmission pipeline owners.
- Linkages to other gas markets, in particular to the northern Australian gas market through new transmission pipelines.
- Greater temporal detail (for example, developing a version of the model capable of yielding prices and quantities on a daily basis), in order to investigate potential short-term gas shortages.
- Explicit representation of gas contracts and their effects on short-term market dynamics.