The Australian gas industry is undergoing a period of extensive change, which includes gas market deregulation, the removal of regulatory barriers to interstate trade and the implementation of a national access regime for gas pipelines.

The objective in this paper is to analyse developments in the eastern states gas market and assess the key features of regulation pertaining to the transmission sector. To assist in this analysis, a model has been developed of the gas industry in eastern Australia. This model will be used to undertake an analysis of the gas market and future pipeline investment.

The paper has the following structure. The first section gives a historical overview of the gas market. The following section presents an evaluation of regulatory regimes and market design. The development of a gas model is then outlined, followed by a discussion of expected changes in consumption and supply patterns. The final section discusses expected developments in the gas market.
Historical review gas market

Over the past twenty years, growth in natural gas consumption has averaged around 5.2 percent a year. The major factors which have contributed to the increase in consumption include: economic growth, a decrease in real gas prices, an increase in the use of gas in the electricity generation sector, and an expansion in the transmission and distribution pipeline network, which has resulted to a substantial increase in the market penetration of gas. Within the regional markets there is considerable variability in the use of natural gas as a primary energy source. This usage varies from less than 10 per cent in Queensland and New South Wales to around 44 per cent in Western Australia.

In 1997-98, natural gas consumption was 860 petajoules, accounting for almost 18 per cent of total energy consumption (Bush et al. 1999). Natural gas consumption is expected to grow at an average rate of almost 4.4 per cent to 2014-15, representing an increase in total energy market share to around 28 per cent. The realisation of this forecast consumption will rely on a number of factors. One of the major uncertainties for growth in gas consumption relates to competition from competing energy sources for power generation. Complementary reforms in all sectors of the gas market are also necessary to facilitate growth in gas consumption compared to alternative fuels.

Historically the Australian natural gas market has been characterised by regional markets, dominated by a single joint venture producer, a single government owned retailer, and with limited pipeline interconnections between the markets. These characteristics reflect both Australia’s geography (large spatial distances between gas supply basins and major consumption centres) and energy policies of earlier state governments.

Recent and expected interconnectors have increased the capabilities for inter-state gas flows. The Interconnect (commenced 1999) can supply around 10-33 petajoules into Victoria (dependent on compression and relative pressures). Current configurations allow only limited flows into New South Wales (around 6 petajoules). Future capacity enhancements of the Interconnect will facilitate interregional flows and the development of competitive secondary trading (for example, swaps) in the eastern Australian gas market.

The completion of the Eastern Gas pipeline (EGP) in late 2000 will represent the first alternative New South Wales supply to the current Cooper basin supply. The EGP will initially deliver a capacity of around 55 petajoules into the New South Wales market, with a potential capacity of 110 petajoules a year (given additional compression). The EGP will present the NSW market with an alternative supply source (with significant spare capacity) and result in significant changes in market supply. The proposed tariffs for the EGP ($0.86/GJ) indicate that gas supply from Gippsland will be competitive with the existing supply from Cooper basin. The release of these tariffs has also seen a reduction of tariffs for Moomba–Sydney from $0.93/GJ to $0.72/GJ (Duke 2000).
Market interconnections will also be enhanced by the possible development of the Papua New Guinea (PNG), Timor Sea and Tasmania pipelines. The latter two pipelines also offer potential links to the New South Wales and Victoria markets, which would further enhance competition in those markets. The future construction of the PNG, Timor Sea and Tasmania pipelines will depend on energy market developments.

Gas market liberalisation has been a significant feature of government policy agenda since the early 1990s. In Australia, the recently implemented national access regime (the ‘Code’) is a key element in gas market liberalisation. The code is designed to regulate third party access to gas pipelines, facilitate the growth of an integrated pipeline network and to enhance the competitive supply of gas. The majority of transmission pipelines in Australia are now covered (or are in the process of being covered) by the Code. Applications for exemptions to the code have been lodged for all major transmission pipelines in Queensland (including the proposed PNG pipeline) and for the Eastern Gas Pipeline (EGP) and Moomba–Sydney pipelines. The National Competition Council is currently considering these exemptions. The proposals for the two latter pipelines indicate that with the commencement of the EGP (provides an alternative supply with significant spare pipeline capacity), regulated access of the two pipelines is not required to ensure competitive market outcomes. The draft decision on the EGP (NCC 2000) indicates that exemption to the code may be granted for the northern section of the pipeline serving Sydney and the ACT, providing the NCC is satisfied sufficient competition exists in those markets.

Figure 1: Australia's natural gas transmission pipelines

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To date, the major outcome of the gas reform process has been to facilitate competitive outcomes in the pipeline sector. At present there is a lack of upstream competition, with a small number of producers (Esso and BHP in Gippsland, Santos in Cooper Basin) dominating production in the eastern gas market. Given the lead times between exploration and supply from new producers, upstream competition will only develop in the longer term. The majority of gas supplies from individual basins is also jointly marketed under long-term take-or-pay arrangements. Contracted supply from the Gippsland and Cooper Basin joint ventures (till 2009 and 2006, respectively) provide over 95 per cent of Victorian and NSW total gas consumption (NCC 2000; Duke 2000). Long term contracts have minimised price fluctuations for producers and wholesalers, but in the absence of gas-on-gas competition these contracts may also have kept prices relatively higher for end users. Contracted supply prices for the Cooper and Gippsland basins are currently around $2.35/GJ to $2.55/GJ (NCC 2000, BCA 2000).

The Upstream Issues Working Group (UIWG) considered the potential for joint marketing arrangements to inhibit gas market competition. UIWG recommended that a requirement for individual marketing by joint venture partners (as occurs in the United Kingdom) would be impractical given the current state of gas market development (UIWG 1999). This concentration of market supply and dominant use of long-term contracts is in contrast to the electricity industry, which has a spot market trading generation in the national electricity market (NEM) and a higher number of suppliers (generators). Notwithstanding the more competitive features of the electricity market, there may still be strategic behavior undertaken by market participants in the NEM (Short 2000). In the gas market, market power may allow current producers to capture some of the cost savings generated by downstream reforms.

**Evaluation of regulatory regimes and market design**

Analysis will be undertaken of the methodologies used in the regulation of the transmission sector and their impact on future pipeline investment. Major issues to be analysed include; rate of return regulation and tariff regimes, regulation costs and developments in secondary markets.

**Third party access and reference tariffs**

In a competitive network market, prices provide the appropriate economic signals for optimal capacity investments. Where effective competition does not exist, regulated rate-of return makes an assessment of the level of risk for existing and new pipelines. There are two general approaches to regulation of network infrastructure. A ‘light-handed’ approach (such as that adopted in New Zealand) relies on national competition laws to address anti-competitive behavior ex-post.
The second approach regulates prices and entry with third party access (TPA) regimes, with either a regulated or negotiated access regime. In Australia a regulated access regime gives customers the right of access to spare capacity on the pipeline network, on the basis of reference tariffs (effectively maximum transportation tariffs) and other terms as published in the access arrangements. The determined rate of return on capital is the major determinant of pipeline tariffs. This system is based on the premise that efficient outcomes are achieved if the rate of return does not exceed what would be earned in alternative investments. When a decision is made on the level of pipeline investment, the owner effectively sells forward the peak period capacity rights. Third party access is more effective in markets where there is an excess of gas supply which can be sold to a number of alternative buyers, and where there is spare pipeline capacity.

The negotiated TPA is a lighter handed approach than the regulated TPA. The negotiated TPA does not necessarily require the submission of detailed access arrangements or the setting of binding reference tariffs, providing the regulatory body is satisfied sufficient competition exists in the market. Compared to a negotiated TPA, the access system adopted in Australia involves higher transaction costs for the parties involved. An important issue is whether the benefits of adopting a regulated access regime outweigh the costs of such a regime. As competition has evolved in the United States, there has been a gradual removal of regulations, which were shown to have incurred considerable regulatory costs and decreased market efficiency. Greater reliance has been placed on market mechanisms (for example, tradable capacity rights) to provide market based incentives for pipeline investment. Transmission and capacity rights for new and competitive pipelines are now often unregulated (Energy Projects Division 1997).

There is also debate on whether the access arrangements provide appropriate incentives for construction of new pipelines (‘greenfields projects). For investment in new pipelines, uncertainty in capacity uptake represents an additional risk for investors. Establishing reference tariffs has imposed a degree of standardisation on the regulated rates of return for Australian pipelines. To date, the one draft decision on such a project, the Central West pipeline, set a rate of return (7.5 per cent) equivalent to the rate set for established pipelines. Inappropriate rates of return may result in ‘undersized’ pipelines or delays in the construction pipeline infrastructure investment until contracted capacity is higher than would occur under competitive market outcomes.

High capital costs are associated with the provision of pipeline capacity, and fixed costs typically represent 80–90 per cent of total costs. Given pipelines exhibit strong economies of scale, there is a nonlinear relationship between pipeline costs and transported gas quantities (throughput). Since regulated tariffs reflect costs and pipeline utilisation, newer and underutilised pipelines have higher tariffs. Average transmission tariffs range from around $0.35/GJ (Longford–Melbourne) to $1.98/GJ (Central West).
Pipeline tariffs in Australia are typically calculated on the basis of a two-part ‘capacity’ and ‘commodity’ charge. Recovery of fixed costs is made through capacity reservation charges, which reflect the right to access pipeline capacity irrespective of the actual amount shipped. The commodity charge is based on actual throughput and reflects variable costs. The efficiency of this tariff structure is based on the premise that end users’ generating relatively high capacity cost requirements (high peak capacity requirements relative to average annual throughput) bear the associated costs of providing that capacity.

Regulatory regimes allow transporters to price their services at rates that enhance market growth. In the short term, tariffs for new pipelines (with significant spare capacity) may be set below the recovery cost, with allowance made to recover any current losses. Appropriate rates of return are achieved over the longer term by market growth (higher throughput) and by future users effectively cross subsidising revenue from initial users (real tariffs decline at a lesser rate than the decline in average costs).

Under the regulated access regime, the transition to cost reflective pricing, together with higher throughput in underutilised pipelines should result in a decrease in average pipeline tariffs. This outcome depends on the relative tariff price paths for transmission and distribution tariffs. Average tariffs may increase if the regulated asset value (typically depreciated optimised replacement cost) is deemed to be higher than the pre-existing accounting value. The removal of any existing cross-subsidies will also result in higher real tariffs for some market segments. In New South Wales, AGLGN has forecast around a 50 per cent fall in distribution tariffs over 2000-04 to around $0.66/GJ for large contract customers (AGLGN 2000). Given an average supply price of $2.40/GJ and a transmission tariff of $0.71/GJ (Moomba–Sydney), the delivered gas price would fall to around $3.77/GJ. However, recent press reports indicate that in Victoria, there has been a 10 per cent increase in the average cost of gas (to $3.85 /GJ) for large industrial customers entering into new supply contracts (The Age, 6 October 1999, p. C2).

Secondary markets

Wholesale gas markets, with secondary trading in gas supply and capacity rights are an integral feature of competitive gas markets in the United States and Europe. With secondary trading in pipeline capacity, pipeline operators compete for the sale of their spare pipeline capacity (interruptible supply) with sales of released (firm) capacity by existing shippers. A competitive market for capacity rights enhances the efficient allocation of pipeline capacity, with an associated price that reflects the value of that capacity. Regulators in the United Kingdom and the United States allow the price of traded capacity to be above the regulated tariff (deemed to recover cost of service). The maximum price for capacity in Australia is fixed by the regulated tariff, and there is no allowance for short term increases in prices to reflect congestion constraints.
Long term take-or-pay contracts inhibit the development of secondary trading and effectively transfer most of the physical and financial risks to end users. These arrangements were facilitated by the presence of vertically integrated government utilities (transportation/retailers) in most Australian markets. With gas market liberalisation, the development of an efficient secondary market for gas supply and transportation is required for large end users to be able to hedge market risks. The development of effective secondary markets also depends on the availability of spare capacity for major markets. In the eastern gas market, there is a lack of spare capacity on a number of major pipelines, where capacity is essentially fully contracted.

Long term contracts and limited spare pipeline capacity also inhibit the potential for new shippers/retailers. To date new entrants in eastern gas markets have been unable to obtain significant gas supplies. The access regimes also allow discounts to be given to existing favored shippers. These arrangements may be appropriate for newer underutilised pipelines by encouraging higher short term uptake. However, in the longer term, nondiscriminatory pricing arrangements would be preferable for encouraging new shippers. The auctioning of capacity on new pipelines may also be a preferable mechanism for allocating new pipeline capacity.

It is expected that there will be an emergence of wholesale energy trading companies in the gas market. These companies will meet producer and transmission requirements by longer term contracting of gas supply and pipeline capacity, and then market this gas to end users under more flexible shorter term contracts. With the development of secondary markets, it is expected that the average length of contracts will decrease, although long term contracts will still form a significant proportion of gas traded in the market. In the competitive US market, around 50 per cent of gas is still traded under medium to long term contracts. In Europe, there has been a move back towards long term contracts in recent years as surplus gas production has declined (IEA 1998).

The majority of Australian gas markets operate under a contract carriage arrangement, with the exception of Victoria, which has a market carriage arrangement. The Victorian model is based on an integrated spot market (commenced 1999) and an independent system operator, VENcorp, who manages system balances. The majority of gas supply in Victoria is still contracted, and the spot market has been characterised by low trading volumes (currently around 6 per cent of total market volume) and low variability in prices.

With a Contract Carriage Model, the network system is managed by bilateral contracts for physical capacity between the pipeline operator and shippers, with the pipeline operator regulating system imbalances. This market model is characterised by a combination of tradable and fixed capacity rights. Quantities must be contracted in advance (typically for periods of one or more years), with charges imposed when actual consumption exceeds...
contracted firm supply. There are secondary gas and capacity markets, which generally provide public information on pricing and traded quantities.

The physical transmission capacity rights have priority levels. Firm transportation services have a higher priority than interruptible services, which give access to available excess capacity after consumption from holders of firm capacity rights has been satisfied. Optimal supply pricing indicates that interruptible supplies should be offered at the same price as firm supplies, unless the pipeline is at full capacity (Lawrey 1998). In Australia, interruptible supply charges are typically higher than firm supply charges (including where there is substantial excess capacity) and do not necessarily reflect capacity constraints. However, it is still expected that the share of interruptible contracts will increase, since these contracts provide greater flexibility for large consumers to manage their load requirements (reduce the risk of charges for unused firm supply) and achieve reductions in total costs.

Underground gas storage is an important component of supply infrastructure in the US and European markets. Storage capacity offers a complementary mechanism to secondary trading in achieving competitive gas market outcomes. With shorter term contracts (and more variable consumption), building storage facilities may be more efficient than investing in additional pipeline capacity. Increased gas storage reduces the need for pipeline investment since pipelines can be sized for (lower) average consumption, rather than (higher) peak consumption. Since gas storage increases both annual and peak supply, increased gas storage tends to reduce average prices and price volatility. Currently, there are minimal storage capabilities in the Australian market, and seasonal load matching is largely achieved by increasing production. With the integration of regional markets, it is expected that underground storage will play a more significant role in managing future consumption requirements.

Gas market hubs are a characteristic of most mature competitive gas markets. A gas hub is a convergence point for alternative gas supplies (often with associated storage capacity) and where gas trade occurs. Advantages of market hubs include the matching of gas supply with consumption, and the enhancement of effective secondary trading. Pricing at the hub often becomes a reference price for the gas market. A short term barrier to the development of a competitive gas market in Australia may be the lack of well located hubs. In eastern Australia, Moomba is the most likely candidate for the development of a gas hub, with future supplies from southwest Queensland gas, PNG or the Timor Sea competing with Cooper basin supplies.

Gas model development

This section outlines the current and proposed development of a gas model which, among other factors, is designed to provide useful indications of changes in capacity (including
spare capacity) and interregional flows under alternative consumption scenarios. The model will also be used to undertake analysis of the costs and benefits of regulation regimes. The first component of the model will focus on the transmission sector and regional gas flows. Future development of the model will provide the framework for detailed analysis of the gas supply and retail sectors.

Gas flows from producing to consumption points are determined by consumption and supply requirements and by transportation costs. Constraints apply to total production over the time period and the maximum annual production. The model requires that gas consumption will be met since pipeline capacity will be added in response to increases in consumption. Pipeline capacity can be increased by either adding compressors, partial duplication of the pipeline (‘looping’) or by the addition of a new pipeline. Investment in capacity takes place as a constant, with investment only undertaken with a specified minimum capacity. These minimum capacities are set by available information on capacity additions (see appendix 2).

The model considers the supply, transmission and investment costs (new capacity) in joining consumption and supply nodes, and minimises the sum of these costs. Each pipeline has a loss factor representing gas used as compressor station fuel.

Consumption is allocated to contracted and uncontracted supply, reflecting available information on long term contracted supply (see appendix 2). Uncontracted supply currently represents a small percentage of total gas supply. In the gas market, uncontracted supply (including short term contracts of less than one year) is expected to increase as current long term contracts reach expiry date. The model structure reflects the above factors and then solves for the lowest delivered citygate price for each specified market. The model is constructed as a LP model, with model equations given in appendix 1. It is anticipated the model will solve annual variables over a twenty year time horizon, commencing in 2000.

This model framework represents the first stage in the development of a model of the Australian gas market. Future model enhancements will include the addition of the Western Australia gas sector to the model, the endogenous determination of supply and consumption, and the modeling of interfuel competition. The effect of institutional factors (for example, regulatory and market regimes) will also be explicitly modeled. Amongst other factors, this will allow the quantification of the costs and benefits of energy market policies and gas market regimes.

Model data

The consumption component utilises ABARE energy consumption forecasts (Bush et al. 1999), consumption projections provided by the transmission companies in their respective access arrangements information and other published information on consumption growth.
The model defines consumption into eight markets; Victoria, New South Wales, South Australia, Brisbane, Townsville, Gladstone, Mount Isa and the Northern Territory. Significant new consumption is identified with startup dates and forecast consumption profiles. Assumptions are made on the probable decrease in long term contracted supply for each of the defined markets, with consumption allocated to contracted and uncontracted supply.

The supply component uses Australian Geological Survey Organisation (AGSO) data on existing and potential reserves to provide estimates on supply capabilities from the major production areas. These areas are defined as the Gippsland basin, Otway Basin, South Australian Cooper Basin, southwest Queensland gas, Bowen/Surat basin, Armadeus Basin, PNG and Timor Sea gas. The AGSO data is used to set maximum annual and total production for the study period. Current gas supply in the eastern market totals around 580 peta-joules/a year, with around 75 per cent of this supply provided by the Cooper and Gippsland basins. Given median consumption outcomes, known reserves in eastern Australia would be sufficient to meet gas consumption until around 2010. After this period, supply would need to be augmented by new discoveries in existing basins or by supply from new sources. The supply price will be derived from available information (see appendix 2) and set as a constant, irrespective of the volume sold.

To deliver an accurate representation of the transmission component, data is used on pipeline capacity, new capital investment, load flows and transmission costs. Information from the access arrangements and associated information is used to derive the appropriate data for the respective pipelines. The model results will depend on some extent on the assumed optimal size, costs and tariffs for new pipelines. These details have been supplied by associated studies undertaken on the feasibility of these pipelines.

Supply prices represent the major component of the delivered price of gas, and lower supply prices will be an essential factor in delivering competitive outcomes for the gas industry. Greater upstream competition in existing supply basins may result in a fall in average supply prices. However, the depletion of resources from current supply sources and the delivery of new higher priced supplies from either PNG or Timor would constrain decreases in the average price of delivered gas.

Data sources are detailed in appendix 2.

**Model scenarios**

There will be two major scenarios developed to analyse regional gas glows in eastern Australia.
In the first scenario, PNG gas and gas to Tasmania comes online from 2002-03. In the Queensland market, it is assumed that the delivery of PNG gas initially creates a market consumption of at least 130 petajoules a year. Timor Sea gas to Darwin and Mt Isa can be delivered from 2004-05 and would initially associated with an additional 55–85 petajoules of gas consumption in the Northern Territory, dependent on the startup of proposed projects. Gas can be delivered to the southern markets utilising backhaul along the Ballera–Mt Isa pipeline. In the second scenario, PNG gas is not delivered and Timor Sea gas may also be delivered to the Gladstone and Townsville markets from 2004-05.

Additional new major pipeline options include the delivery of Minerva gas to Adelaide, and the delivery of SWQ gas to Townsville. Other capacity expansions will involve increased compression and looping. Capacity expansions will be dependent on consumption and on the load profiles in the respective markets. For example, the maximum transmission capacity required to meet peak winter consumption in Victoria and South Australia is around 30–40 per cent higher than average annual consumption requirements (Epic Energy 1999; VENcorp 1999; TPA 1998).

The feasibility of Timor Sea gas for domestic gas supplies is currently being investigated by the Timor Gap Joint Authority and the coventurers in the Timor Sea liquids recovery/gas recycling project (expected commencement in 2004). The provision of gas for domestic gas supplies is dependent on identified potential consumption for natural gas in both the domestic and export markets. The developers of the PNG gas supplies have signed ‘memorandums of understanding’ (dependent on delivery prices), which represent sufficient volumes (up to 200 petajoules a year) to underpin development of the PNG pipeline. However, the actual development of this pipeline is dependent on energy market and policy developments. These developments include the ability of gas fired generation to compete with existing and new coal fired generation in Queensland. Policy initiatives, such as the setting of minimum targets for sourcing electricity from gas fired generation [proposed 15 per cent target (including renewables) in Queensland from 2005] would enhance positive outcomes for the use of gas fired generation.

A median and high consumption case will be associated with each scenario. The median consumption case assumes gas market growth in line with ABARE projections, amended by recent market developments. Under this case it is expected average citygate prices would remain constant in most markets until 2010. Over the period 2010–15, supply constraints would then result in an average increase in real citygate prices of around 3 per cent [that is, $2.90/GJ (Melbourne) – $3.50/GJ (Brisbane)]. Energy consumption projections for the high scenario assume future market dynamics enhance the competitiveness of gas and stimulate market consumption. In this case average citygate prices from 2000–15 would fall by around 5–8 per cent [$2.70/GJ (Melbourne) – $3.15/GJ (Brisbane)].
Since the introduction of the national electricity market, the market share of coal fired generation in the eastern markets has increased (ESAA 1999). Delivered gas prices of $3/GJ equate to electricity prices of around $35/MWh (Timor Sea Consultative Group 1999). Given the current level of electricity spot market prices (average $25/MWh), gas fired generation would typically only be viable for peak load generation. As an example, in January 1999, New South Wales spot prices exceeded $35/MWh for less than 10 per cent of the total monthly load (NEMMCO market data). New gas fired power generation could be expected to become competitive over the period 2005–10. This outcome is dependent on the increased competitiveness of gas fired generation (includes greater technical efficiencies, lower gas prices and higher electricity pool prices) and the rate of take-up of existing excess generation capacity. Actual outcomes will also be dependent on policy developments in the energy market.

Regional market developments
With the increase in imports of cheaper coal fired electricity from Victoria, gas consumption in South Australia has remained relatively static in recent years. Under the high consumption scenario, gas would become more competitive due to the fall in delivered gas prices and an expected increase in the price of imported electricity. The increase in consumption in South Australia is most likely to be meet by Cooper Basin supplies, with some uptake of southwest Queensland gas after 2010. Supplies from these basins are likely to exclude significant supplies of PNG and/or Timor Sea gas entering the South Australian market.

In Victoria, gas supply from Gippsland basin via the Longford–Melbourne pipeline (990 terajoules a day) is currently unable to meet average peak winter consumption (1030 terajoules a day). Additional supplies can be derived from LNG peak shaving, Interconnect supplies or from underground storage at Iona. Total system capacity is estimated to be around 1210 terajoules a day (440 petajoules a year) (VENcorp 1999). Contracted supply from underground storage at Iona (30 petajoules May–Sept) provides around 8–10 per cent of annual consumption. These facilities, together with LNG peak shaving (30 petajoules in peak winter consumption), are important components in meeting peak winter consumption and reduce the additional capacity requirements for the Longford–Melbourne pipeline.

Gippsland basin supplies are expected to continue to supply the majority of Victoria’s supply over the next 15–20 years. Current system capacity (given 100 per cent load profile) could continue to meet peak winter consumption (30 per cent higher average consumption) under a median scenario. Additional capacity would be required under any high consumption scenario. Gas supplies via the Interconnect are expected to increase and would primarily be competitive in meeting peak consumption. Given pipeline capacity constraints and relative tariffs, Interconnect supplies are expected to continue to meet less than 10 per cent of total Victorian consumption.
In New South Wales, the EGP could potentially supply around 40 per cent of total consumption by 2014-15. Growth in gas consumption for electricity generation may account for up to 50 per cent of the increase in gas consumption in New South Wales in the next 15–20 years. Given median consumption outcomes, the majority of New South Wales gas would continue to be supplied by the Cooper Basin and Gippsland basins. Given high consumption, it is expected supply from Cooper basin (post 2010) would largely be directed to the South Australian market, and additional requirements in New South Wales would be met by southwest Queensland gas.

In Queensland, the commissioning of the PNG pipeline will generate a significant increase in gas consumption. Given the advent of PNG Sea gas supply into Queensland, PNG gas is expected to supply the majority of the Queensland market after 2003. The use of gas for electricity generation in Queensland is currently constrained by the delivered gas price in that state. Depending on competition from coal fired generation, gas consumption in the Queensland market could be expected to increase by around 150–200 petajoules over the next 15–20 years. Growth in gas consumption for electricity generation could account for up to 50 per cent of the increase in gas consumption in Queensland.

Given competitive supply prices and proposed tariffs around $1.00/GJ, PNG gas could be competitively delivered to the Gladstone and Townsville markets, and result in major consumption growth in those markets. The development of markets in Gladstone is dependent on significant industrial consumption growth (for example, Comalco alumina refinery). The Townsville market does not currently have access to gas supplies. Potential consumption in that market is associated with minerals processing and gas fired electricity generation and is estimated to be around 55 petajoules (Timor Sea Consultative Group 1999). Gas consumption in Brisbane is most likely to be met by existing sources with associated capacity increases on the Roma–Brisbane pipeline. Depending on delivered prices from southwest Queensland gas, small amounts of PNG gas could also enter the Brisbane market.

Given available information on costs and proposed tariffs, it appears Timor Sea gas will be competitive in the Northern Territory and Mount Isa markets (tariff around $1.00 GJ), with possible entry into the southern markets. Market potential for Timor Sea gas appears to be highest in the Northern Territory and Mount Isa markets. The delivery of gas to the Northern Territory should result in additional initial consumption in that market of 50–150 petajoules a year, dependent on the startup of a number of proposed projects. It appears unlikely that the delivered cost of Timor Sea gas to Townsville (tariff around $1.70) would be competitive with PNG gas or with coal fired generation in Queensland markets. If PNG gas is not delivered to Queensland, Timor Sea gas could be delivered to those markets from 2004-05.
The potential for penetration of Timor Sea gas and/or PNG gas into the southern markets (South Australia, Victoria, New South Wales) relies largely on supply constraints developing in those markets. The delivery of these gas supplies to major southern markets would require additional capacity on the Moomba–Sydney pipeline (compression could double current capacity to around 300 petajoules), Moomba–Adelaide pipeline (probable looping) and the Interconnect to Victoria (potential capacity of 90 petajoules). Although estimates of probable additional reserves for current supply basins suggest possible supply constraints towards the end of the study period, past history suggests that these estimates are likely to be conservative. If this were the case, PNG and Timor Sea gas would largely be uncompetitive in the southern markets over the next fifteen years.

Conclusion

The Australia gas market is expected to develop features evident in competitive gas markets. These features include market hubs, greater use of underground storage facilities and competitive secondary trading of gas and pipeline capacity. Regulatory regimes need to actively promote the development of these features, which would result in an important new competitive dynamic in the Australian gas market. To facilitate efficient pipeline investments, regulatory regimes also need to encourage an appropriate balance of short and long term trading mechanisms. It is expected that there will be a significant decrease in the use of long term bilateral contracts in the gas market, associated with a move to short term trading in supply and pipeline capacity. Increased competition in the gas transportation sector would require a reassessment of regulatory requirements. It may be that a move towards a more light-handed regulatory approach is more appropriate in the longer term.

Continued reforms of the Australian gas market should result in an increased market share of gas in total energy consumption. However, the relative absence of upstream competition is likely to inhibit competitive outcomes for the gas industry in the medium term. In the longer term, upstream competition will increase with new producers in existing basins, and with supplies of PNG and Timor Sea gas. The market penetration of supply from new gas supply basins into the southern markets will increase as constraints eventuate on supply from existing basins (post-2010).

In the eastern gas market, increasing interconnection of regional markets will diminish the arbitrage possibilities between those markets and should result in a convergence of gas prices for standard services. There will a significant increase in interregional gas flows and gas swaps between shippers are likely to become a feature of the market. Moomba is likely to develop into a gas market hub, with both physical and secondary trading. The above outcomes should result in a decrease in the delivered price of gas in all major markets and the enhancement of competitive outcomes for natural gas in the Australian energy market.
Appendix 1: Model equations

Objective function

Minimise $\sum_{t=1}^{T} (1 + r)^{-t} \left[ \sum_{i} \sum_{j} c_{ij}(t)I_{ij}(t) + \sum_{i} d_{i}(t)X_{i}(t) + \sum_{i} \sum_{j} e_{ij}(t)V_{ij}(t) \right]$, where

- $I_{ij}(t)$ is investment in year $t$ in a unit of pipeline capacity between nodes $i$ and $j$, in PJ/year;
- $X_{i}(t)$ is gas production in year $t$ at node $i$, in PJ/year;
- $c_{ij}(t)$ is construction and capitalised overhead cost in year $t$ of a unit of pipeline capacity between nodes $i$ and $j$, in $$/PJ;
- $e_{ij}(t)$ is operating costs (other than costs of gas used in compression) in year $t$ for pipeline link $ij$, in $$/PJ of net gas flow;
- $d_{i}(t)$ is production cost of gas in year $t$ at node $i$, in $$/PJ;
- $r$ is annual rate of discount.

The first term of the objective function represents the present value of the future cost of adding pipeline capacity. The second term represents the present value of the future cost of gas production. The third term represents the present value of future operating costs (net of gas used in compression) of the pipeline system. The objective function does not include a value for pipeline and other assets that survive beyond the terminal year $T$. This reflects the fact that pipelines have only use value during the period of gas extraction.

The objective is to minimise the costs of meeting specified timepaths of gas use at all nodes for nonnegative variables subject to the constraints below.

Gas balance constraints

$C_{i}(t) + \sum_{j} V_{ij}(t)(1 + k) \leq X_{i}(t) + \sum_{j} V_{ji}(t)$, where

- $C_{i}(t)$ is gas use in year $t$ at node $i$, in PJ/year;
- $V_{ij}(t)$ is net gas flow in year $t$ from node $i$ to node $j$, in PJ/year;
- $k$ is use of gas for compression as a proportion of the net flow.

This constraint states that at each node $i$, the use of gas cannot exceed the availability of gas taking into account losses and net flows to and from other nodes.

Pipeline capacity constraints

$V_{ij}(t) \leq Cap_{ij}(t)$, where
$Cap_{ij}(t)$ is the capacity in year $t$ of the pipeline linking nodes $i$ and $j$, in PJ/year;

This constraint states that in any year for any link the gas flow cannot exceed the capacity.

**Pipeline capacity equation**

$Cap_{ij}(t) = Cap_{ij}(t-1) + I_{ij}(t)$ and $Cap_{ij}(0) = Cap_{ij}$

This equation records the evolution of capacity of each link over time. It is assumed that no physical depreciation of pipeline capacity is required over the time horizon.

**Annual gas production constraint**

$X_{i}(t) \leq \bar{X}_{i}(t)$, where

$\bar{X}_{i}(t)$ is maximum gas production at node $i$ in year $t$.

**Gas reserve constraints**

$\sum_{t=1}^{T} X_{i}(t) \leq X_{i}$, where

$X_{i}$ is maximum gas production at node $i$ over the time horizon equal to initial gas reserves at that node.

**Gas use constraints**

$C_{i}(t) \geq C_{i}^{*}(t)$, where

$C_{i}^{*}(t)$ is minimum gas use requirement in year $t$ at node $i$.

The model can be modified to simulate the effects of minimum flows for certain links representing contracted gas flows that cannot be altered. This involves additional minimum bound constraints on the flow variables.
Appendix 2: Data

Consumption data

• Access Arrangements and Access Principles (various) and associated documentation available on ACCC, NCC and VENCOrp websites and from the respective pipeline operators.

Production data

Production prices
• Access Arrangements and Access Principles (various) and associated documentation available on ACCC, NCC and VENCOrp websites and from the respective pipeline operators.


The above documentation provides information on current supply prices ($1999). Real supply prices are assumed to be constant for the period 2000–15.

Pipeline tariffs and investment
• Access Arrangements and Access Principles (various) and associated documentation available on ACCC, NCC and VENCOrp websites and from the respective pipeline operators.


Investment costs for pipelines and capacity expansions are derived from the above information. Where specific information is not available on proposed new investment, average costs are derived from past investment costs.
References


AGL/Petronas 1999, Access Principles for PNG Queensland Pipeline, Submission to the Queensland government.


AGA (Australian Gas Association) 1999, Gas Statistics Australia, Canberra.


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