Opportunities for Timor Sea Gas in Northern Territory & Queensland

Prepared by
M. J. Kimber Consultants Pty. Ltd.
27 May 1999
MINISTER’S MESSAGE

I am pleased to introduce the second report commissioned by the Timor Sea Consultative Group investigating gas infrastructure development and the opportunities for Timor Sea gas entering the domestic Australian marketplace. The report is an important document that further confirms that Timor Sea gas could be a competitive energy source, even in the eastern States.

The timing of this report is excellent. The recent softening of international liquefied natural gas (LNG) markets has renewed the focus on domestic gas marketing opportunities; legislation for third party access to gas pipelines and the proposal for a Papua New Guinea gas pipeline to Queensland are pointing to more mature and competitive gas markets; greenhouse gas concerns are promising increased gas usage; and the purchase of BHP's Timor Sea assets by Phillips Petroleum could see the fast-tracking of the Bayu-Undan project.

These changes have led to a re-focusing of energy to exploring the real opportunities of piping Timor Sea gas to Darwin for domestic markets in the Northern Territory and Queensland. This new report supports this view, suggesting strong prospects for markets in the Northern Territory, as well as Mount Isa and Townsville.

The Greater Timor Sea area, covering the Bonaparte and Browse basins to the north and west of Darwin holds gas reserves of nearly 40 trillion cubic feet. This is more than sufficient to guarantee long term gas supply to Australia, and having sufficient reserves to export LNG when international markets are secured.

According to this report, natural gas business opportunities abound. It identifies an annual domestic market for Timor Sea gas of up to 360 petajoules by 2013.

The Northern Territory Government is keen to see the development of the Timor Sea gas reserves. I am committed to supporting the companies involved in the Timor Sea in their endeavour to develop and market their gas in Australia.

DARYL W. MANZIE
INTRODUCTORY COMMENTS BY THE TIMOR SEA CONSULTATIVE GROUP

The Timor Sea Consultative Group consists of the potential Timor Sea gas producers (British-Borneo, Petroz, Phillips, Santos, Shell, Timor Sea Petroleum and Woodside) together with pipeline companies (Epic Energy, AGL, Duke Energy and Interstate Energy). The Group, convened by the Northern Territory Government’s Office of Resource Development, Department of Mines and Energy, commissioned a new research project to identify new opportunities for Timor Sea gas in Australian markets. A full listing of the Group membership is at Appendix A to this publication.

Timor Sea gas could supply domestic Australian markets and/or support a robust liquefied natural gas (LNG) export market. The LNG market is not the subject of this study. There are currently four Timor Sea gas fields that could provide initial supplies for either market:

Bayu-Undan, operated by Phillips Petroleum with co-venturers Santos, Inpex, Petroz, Kerr-McGee (Oryx) and British-Borneo.

Petrel/Tern, operated by Santos, with Boral and Bonaparte Oil and Gas as joint venture partners.

Greater Sunrise, including Sunset, Loxton Shoals and Troubadour, operated by Woodside in joint venture with Shell and Phillips Petroleum.

Evans Shoal, operated by Shell in joint venture with Timor Sea Petroleum.

This report furthers the work of the ACiL Economics and Policy Pty Ltd group who were commissioned to consider “Prospects For Timor Sea Gas in the Australian Market”. That report was released in February 1998. ACiL provided market demand projections and contracted demand profiles for individual markets. Most of these have been reproduced in Appendix B.

Since the release of the initial gas to Australia study, there has been considerable interest in the matching of Timor Sea gas with domestic gas opportunities. In addition, pipeline tariffs have become more competitive and haulage rates for the gas pipeline from Papua New Guinea have been released.

The Group commissioned Mr Max Kimber of M J Kimber Consultants Pty Ltd to prepare a report on the potential markets for offshore Timor Sea gas. The focus of the report is on markets in the Northern Territory, southern and eastern Australia and the cost of delivering Timor Sea gas to those markets, in light of recent gas transmission developments.

Building on the earlier study, and after reviewing potential gas markets and pipeline infrastructure, Mr Kimber’s new report concludes that prospects for the development of Timor Sea gas are high, with a total annual market of about 200 petajoules (PJ) by 2010. The prospective market would be as high as 360 PJ if the proposed fertiliser and methanol manufacturing plants are built in the vicinity of Darwin.
Mr Kimber envisages gas could come on shore from up to four different Timor Sea fields to supply gas for electricity generation in the Northern Territory and to supply mineral processing operations in Darwin and Gove (Nhulunbuy) and possibly other gas-using operations in the Darwin region.

The consultant believes Timor Sea gas could also be piped south east to Mount Isa to augment gas from the Cooper Basin and be used in gas trading, swaps and exchanges as the gas market becomes more open. The prospect of supply to Townsville is less likely unless the landed gas price in Darwin is very competitive and/or the demand enroute or in the Townsville region exceeds the projections contained in this report.

Mr Kimber sees the Northern Territory and the Mount Isa region as prime markets for Timor Sea gas. Gas supply to Townsville from the Timor Sea is very dependent on the gas price and the market size. The Group notes that a Mt Isa to Townsville pipeline would also provide an “energy backbone for MITEZ” - the Mt Isa to Townsville Economic Zone.

Members of the Consultative Group are keen to work with gas transporters, customers and governments to ensure win/win solutions and are optimistic about the prospects for delivery of Timor Sea natural gas for use in domestic markets starting with north Australia.

The Group also notes that there are many new electricity projects proposed for Queensland (see Appendix C). The developments based on coal are a threat to the entry of any new gas supplies into northern and central Queensland, with the exception that Timor Sea gas is not likely to target electricity generation in central Queensland. The introduction of greenhouse gas emission requirements on the use of coal for electricity generation may have a positive effect on the entry of new gas supplies to the Brisbane and Gladstone markets.

Readers should note that this report represents the views of the consultant, Mr Kimber, and may not necessarily represent the views of the Timor Sea Consultative Group, either individually or as a group.

All information in this report was current at the time of going to print, but is subject to change without notice. Companies making commercial decisions should be guided by their own research and not rely on the contents of this report.

Neither the Timor Sea Consultative Group nor Mr Kimber will accept liability for any decisions taken on the information presented in this report.

Finally, the Timor Sea Consultative Group would like to acknowledge and thank Mr Max Kimber for his efforts in researching and preparing this report.
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Gas Infrastructure Development

Opportunities for Timor Sea Gas in Northern Territory & Queensland

A Public Report
prepared by
M.J.Kimber Consultants Pty. Ltd.
27th May 1999
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1 INTRODUCTION

Mr Max Kimber of M. J. Kimber Consultants Pty. Ltd. was chosen by the Northern Territory Office of Resource Development and the Timor Sea Consultative Group, to prepare a report on the prospects for the development of gas supplies from the Timor Sea for markets in the Northern Territory, southern and eastern Australia. The report reviews these markets and re-evaluates pipeline costs to each of these markets. The report focusses on markets and the costs of delivery of Timor Sea gas, taking into account recent gas transmission developments and the announced tariffs for PNG gas and the timing of opportunities.

The report also provides a review of a report on gas markets and Timor Sea petroleum developments which was carried out by ACIL Economics and Policy in November 1997. Since that time there have been significant changes in both the supply side and possible markets for gas. The prospects of new industrial and mineral processing plants in the Northern Territory have increased since the release of the ACIL study. Plans for the development of gas fields in the Timor Sea have also been advanced while the prospects for the development of gas fields in Papua New Guinea and an associated pipeline to Townsville and Gladstone have not been finalised.

There is an increasing awareness of the significant role that gas trading will have, once pipeline infrastructure is established. All of these changes to the demand/supply dynamics provide new opportunities for gas from the Timor Sea to meet gas demands in the Northern Territory, Queensland and, through trading in an open market environment, to other south eastern states.

The dynamics of the entry of Timor Sea gas into the market can best be illustrated by the flow chart in Figure 1.

Figure 1: Entry of Timor Sea gas into existing and potential markets - Dynamics and Drivers

1 Derived from ACIL report Prospects for Timor Sea gas in the Australian Market November 1997
2 DEMAND FOR TIMOR SEA GAS - ACCESSIBLE MARKETS

The target markets for direct sales of gas from the Timor Sea include the “Top End” (Darwin, Nhulunbuy, and south to Mataranka), Mt Isa and Townsville. Other markets, of similar viability, can be accessed through gas trading, swaps and exchanges by interconnection with the existing pipeline from Ballera (Queensland) to Mt Isa. None of these markets can be said to be a certainty, and the Timor Sea producers and their pipeline partners will have to enter into vigorous price competition to succeed in these markets.

2.1 Gas Price Expectations for Electricity Generation

It is generally accepted that the delivered gas price for electricity generation has to be within the low range to allow base load gas fired combined cycle units to be competitive with green fields coal fired plants. A gas price of $3.00/GJ results in an electricity price of $35 - $38/MWh at the terminals of a combined cycle gas turbine driven generator. These prices are regarded as “new entrant” price levels for base load generation and are considered by the electricity industry as appropriate in the national electricity market for the future.

At present there is no price recognition of the reduced carbon dioxide emissions from gas fired plants. Given the community expectations about the need to reduce greenhouse gas emissions and Australia’s commitment to the Kyoto agreement, it is surprising that a number of large coal fired generating stations are being proposed in southern and central Queensland. These power stations appear to have the strong support of the Queensland Government, despite their negative implication in respect of meeting greenhouse gas emission targets recently agreed to by the Commonwealth Government. The need for new base, intermediate and peak electricity generating capacity in Queensland represents a very important marketing opportunity for gas producers and pipeline companies, and is clearly in the long term national interest of Australia.

2.2 Gas Price Expectations for Mineral Processing

There can be no clear rule for determining the threshold gas price for mineral processing - it depends on the commodity, the degree of value-adding inherent in the process, the flexibility with locations and the cost of alternative energy sources. Where electricity is a primary input to the process, such as aluminium or magnesium production, the gas price must be in the very low range to make any project world competitive.

Gas supplies to alumina refineries often compete with coal for process heat and with fuel oil for calcination. Hence an average gas price in the low to medium range is acceptable and allows a refinery to compete in the world commodity market. In general, the same applies for other mineral processing plants.

Mineral processing projects that are not site specific (eg Comalco at Gladstone or Sarawak) and petrochemical projects need highly competitive gas prices. Thus for example, methanol production needs extremely low gas prices as other plants have been located near big gas fields in the Middle East or remote locations (eg Southern Chile).
2.3 Median Case Market for Timor Sea Gas

This report assesses the potential of the target markets on the assumption that market share will be sought aggressively, and has arrived at the estimated size of the potential market for Timor Sea gas. This is illustrated in Figure 2.

![Figure 2: Markets for Timor Sea Gas - Median Case](image)

This is consistent with the ACIL market projections for Mt Isa and Townsville and a little higher for the Top End because there are more mineral projects in the estimate. A selection of the ACIL projections is at Appendix B.

The low case would not include the Townsville market because of the entry of gas from Papua New Guinea or coal seam methane. The more intensive use of coal for electricity generation is less important as it may only marginally reduce the available market for Timor Sea gas. Entry into Mt Isa should occur but subsequent trading may also be more limited.
2.4 Potential Market for Timor Sea Gas

With a sufficiently low landed gas price to make Darwin-based manufacture of fertilisers and methanol for export to Asia, the possible gas demand could be increased by up to 170 PJ per year. The total potential market for Timor Sea gas is illustrated in Figure 3. Such a low landed gas price would also enhance the opportunities to supply Townsville and for trading through Ballera.

Figure 3: Markets for Timor Sea Gas - High Case Including Methanol and Fertiliser Plants
3 Northern Territory

Current supplies of natural gas in the Northern Territory have limited reserves, which means that a number of major mineral processing, electricity generating and petrochemical projects can only proceed if significant sources of new gas become available at world competitive prices. Based on current knowledge of existing gas fields, such gas supplies can only come from the Timor Sea. This market analysis suggests that the potential market would be robust and represent about 60 PJ per year by 2006 - possibly sufficient to underpin initial development of some offshore gas fields. If landed gas prices are favourable, it may be possible for the development of methanol and fertiliser manufacturing plants in the vicinity of Darwin. These could add up to 170 PJ of additional demand to the Top End.

3.1 Electricity Generation

The Northern Territory Power and Water Authority (PAWA) is the primary supplier of electricity to residential, commercial and industrial customers in the Northern Territory, except to remote mining sites, such as Nhulunbuy. In the financial year 1997/98 PAWA sent out 1,5222 GWh, more than 98%3 of which was generated using 17.0494 PJ of natural gas. As such, PAWA represents the largest consumer of natural gas in the Northern Territory and the most likely to require augmentation of its supply sources. PAWA suggests that contracted gas from the Amadeus Basin may not meet demand and anticipates that little gas will be available under existing contracts by 2010. This is shown in Figure 4. I understand that the Amadeus Basin producers and PAWA are negotiating for additional gas supplies to alleviate shortfalls in gas supply over the period to 2005. However, supplies thereafter remain problematic.
The PAWA predictions of gas demand shown in Figure 4 do not include gas fired generation in Alice Springs, and show only modest compound growth. In the last few years, the rate of growth of gas used for electricity generation has been about 4.5% pa. This has closely tracked the growth of the Territory's Gross State Product (GSP). Access Economics has predicted that the growth rate of the GSP will continue at between 4% and 5% over the next 5 years. Based on the GSP growth forecasts and increased per capita use of electricity for air conditioning, I have reassessed the gas demand for electricity generation and have arrived at the demand growth shown in Figure 4.

This report's demand assessment is based on a growth rate of 3% pa, which represents a very conservative approach to electricity demand growth and generally tracks PAWA's forecasts until 2007. It also includes the influence of efficiency improvements, but assumes that the step reductions forecast by PAWA as a result of the termination of existing contracts do not occur.

The current price paid by PAWA for delivered gas is high by Australian standards and results in high electricity prices, thus reducing the competitiveness of electricity for industrial development in Northern Territory. If lower prices cannot be achieved, the Northern Territory will lag behind other states of Australia in attracting investment that requires world competitive electricity pricing.

3.2 Alumina Refinery

The alumina refinery at Nhulunbuy, in north eastern Arnhem Land, operated by Nabalco, a joint venture between Swiss Aluminium Australia Limited and Gove Aluminium Limited, produces approximately 1.8 million tonnes of alumina (aluminium oxide) from nearby bauxite deposits. The refinery uses imported fuel oil for process heat, calcination and electricity generation. If all these processes were converted to natural gas, it is estimated that the gas demand would be approximately 25 PJ per year. Imported fuel oil prices (free of excise for mineral production and processing) are very low at present and gas may not be competitive. However, given the crude oil price trends and the need to minimise sulphur and carbon dioxide emissions, gas should become an attractive option.

3.3 Magnesium Metal Project

Mount Grace Resources NL has proposed a magnesium metal project based on a large deposit of high grade magnesite near Batchelor (approximately 90 km south of Darwin). Samples of the magnesite have been found to be satisfactory for feedstock for a magnesium refinery and plans are being developed for a more comprehensive feasibility study. It appears that this project is not at the same advanced stage of development as two other Australian and some overseas projects and hence I have assumed that it will begin operation in about 2006. I have also assumed that the proposed plant will produce about 40,000 tonnes of electrolytic magnesium per year after a one year ramp up phase.

The estimated gas demand for the Mt Grace magnesium smelter would be approximately 10 PJ per year for electricity generation, gas feedstock and steam raising. Given the world competitive nature of the magnesium metal market, and taking into account other Australian, Canadian and African magnesium metal projects, I believe that the threshold price for gas would need to be comparable to the price of gas needed for electricity in other States.

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5  Ibid. 6  Access Economics - Private Communication 7  The low electricity prices in NSW and Victoria during 1998 were largely as a result of excess capacity of base load generators that were bid into the pool at price levels to ensure dispatch. By mid-1999, the situation has changed, with increases in time weighted average prices as shown for the week ending 1 May 1999 - NSW $32.52/MWh; Queensland $56.63/MWh; SA $45.76/MWh; Snowy $32.95/MWh; VIC $33.04/MWh. The Queensland time weighted average pool price has been significantly higher than the figure shown at various times in 1999. 8  Based on information provided by the Northern Territory Department of Mines and Energy 9  Based on information gathered from DME and representative of Mount Grace
3.4 Brown’s Prospect - Cobalt, Lead, Nickel

The Brown’s ore body is located near Batchelor and contains significant quantities of cobalt, lead, nickel, copper, zinc and silver. The mine and associated mineral processing facilities are expected to start production in 2001 - 2002 and will produce lead, cobalt, copper and nickel metals. The ore treatment process planned will not require significant quantities of energy, other than for electricity generation. Approximately 40 MW peak generating capacity will be required, which translates to a gas demand of 2 PJ, assuming that combined cycle gas turbines will be used to augment PAWA supplies if the processing plant is connected to the grid.

3.5 Ranger / Jabiluka

The Ranger uranium mine and processing plant is located about 230 km east of Darwin. Diesel fuelled generators supply approximately 90 GWh per year to the mine, processing plant and town of Jabiru. It is expected that the ore from Jabiluka will be transported to Ranger for processing. Koongarra is a third deposit in the area. The additional processing will not significantly increase the gross energy consumption in the area.

If the electricity generating station was converted to gas firing, its consumption would be about 1 PJ per year. A gas pipeline to serve the Ranger site would probably be marginally economic, but may deliver energy at a lower price than would be available from a new electricity transmission line, given that the generating plant is already on site and can be converted to natural gas firing. However, it could be argued that the combination of low demand and the difficulties that could be encountered in the construction of a pipeline through Kakadu National Park could render supply of gas to Ranger/Jabiluka impracticable.

3.6 Possible Methanol Plant

Timor Sea gas onshore could provide feedstock for major petrochemical projects in the Darwin region. Methane based projects are the most likely to proceed, although ethane, propane and butane petrochemicals are possible.

Methane petrochemicals could begin with the production of methanol. Stage one of a new world scale methanol plant in the Darwin region would consume approximately 75 PJ, and would produce 2 million tonnes of methanol per year. A similar sized second stage would require another 75 PJ per year.

The price of natural gas feedstock, which is the starting point for methanol production, will be a critical factor in determining whether a project proceeds. Darwin’s ability to attract a methanol project will also be dependent upon issues like sovereign risk and security of gas supply in other countries.

Darwin offers a geographically strategic location for any methanol producer aspiring to compete in the Asian market. Darwin also offers modern infrastructure and port facilities, which complement export orientated projects. The Asia-Pacific region accounts for approximately 25% of world methanol consumption, and although there has been a slowing in methanol demand in the region, many forecasters regard this as a temporary lull, with a return to strong growth rates in the short to medium term.
Methanex has recently stated that Northern Australia would be an ideal location for a methanol plant, firstly because it is where several developers plan to bring gas ashore, [from the Timor Sea] and secondly because it is ideally placed to service markets in Asia.”

However, the gas consumption of a methanol plant has not been factored into the median case Territory gas consumption because insufficient work has been done on the concept and the need for world competitive gas prices.

3.7 Possible Fertiliser Plant

Timor Sea gas onshore in Darwin has the potential to attract investment in fertiliser manufacturing. Two possibilities that are being explored by the Northern Territory Government are the establishment of an ammonia/urea plant and the establishment of a phosphate based fertiliser plant. There are obvious synergies with the production of ammonia/urea and ammonium based phosphate fertilisers such as di-ammonium phosphate (DAP) and mono-ammonium phosphate (MAP), the common factor being the production of ammonia. Ammonia is produced from synthesising natural gas.

The scale of an ammonia/urea plant located in Darwin is difficult to judge. The recently announced Plenty River plant to be located in WA and the proposed Incitec - BHP ammonia/urea project based on Victorian gas both have planned annual production of approximately 700,000 tonnes of urea. There are variations on this depending on production of ammonia for other purposes and markets being targeted. A urea plant producing one million tonnes is estimated to use approximately 21 PJ per year.

Asia is by far the biggest market for ammonia, with China and India having both the greatest production capacities as well as being the major consumers and importers of urea in the region. Both countries account for a major share of the planned increase in world production capacity for ammonia.

The price and quantity of gas will be a major factor in Darwin’s ability to attract an ammonia/urea plant. Given competing uses for gas in India and China, principally for power generation, part of the forecast expansion in capacity could conceivably be located in Darwin where long term access to gas supplies may be more secure and cheaper. The potential market for Darwin based production is likely to be in Asia.

Ammonium based phosphate fertilisers such as MAP and DAP have potential given the synergies with an ammonia/urea plant and the extensive rock phosphate deposits situated off the Barkly Highway east of Tennant Creek. This is a similar plant to the new Western Mining fertiliser project at Phosphate Hill in North West Queensland which is set to become a major supplier of DAP and MAP in the Australian market.

The Northern Territory project could use about 9 PJ of gas for an annual production of 1 million tonnes of DAP and MAP. However, this component of gas demand for fertiliser manufacture has not been factored into either the median case, nor the high case because of strong competition from the Phosphate Hill project. The remainder of the gas demand for fertiliser manufacture has been only incorporated into the high case because insufficient analysis has been done on the concept.
3.8 Other Mining/Processing Plants

Most other mining or ore processing plants in the Northern Territory are in remote areas and appear to have insufficient demand to justify a gas supply. Table 1 sets out the possible demands for gas and its probable availability. One must also recognise the differing economic drivers that face mine developers compared to pipeline developers. The viability of mining and ore processing depends primarily on commodity prices and because of their volatility, developers and financiers expect high risk premiums.

Conversely, the developers of pipelines look for long term contracts and secure markets which translate to an expectation of lower risk premiums and market growth and hence lower pipeline haulage tariffs. If a pipeline is built to a single mine or mining province that is dependent upon a single or small range of commodities, then its developer will expect to incorporate a miner’s risk premium in its returns on the pipeline. As a result, haulage tariffs will often be so high as to make the delivered price of gas uncompetitive against liquid fuels. This reasoning has been used to develop Table 1.

<table>
<thead>
<tr>
<th>Mine Name &amp; Location</th>
<th>Possible Annual Gas Demand</th>
<th>Probability of Supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tanami - 650 km NW of Alice Springs</td>
<td>0.3 PJ</td>
<td>Low - small gas demand and long pipeline</td>
</tr>
<tr>
<td>The Granites - 560 km NW of Alice Springs</td>
<td>0.75 PJ</td>
<td>Low - small gas demand and long pipeline</td>
</tr>
<tr>
<td>Gemco - manganese ore mine on Groote Eylandt</td>
<td>0.7 PJ</td>
<td>Low - Gemco is on an island and could only be supplied by a 75 km lateral from the proposed pipeline to Nhulunbuy, of which 47 km would be sub-sea.</td>
</tr>
<tr>
<td>Temco - manufacture of ferro-manganese alloys on Groote Eylandt</td>
<td>6-7 PJ</td>
<td>Low - Temco has contract in Tasmania to supply at modest prices. Gas delivered to Groote Eylandt for electricity generation may not be competitive</td>
</tr>
</tbody>
</table>

Table 1: Prospects of gas supply to mine sites

3.9 Summary of Gas Demands for Northern Territory

Figure 5 and Figure 6 summarise the composite gas demand forecasts for the Northern Territory. As can be seen, even without both the fertiliser and petrochemical plants, the gas demand is substantial and possibly adequate to support the development of a new gas supply from offshore. However, in order to ensure development of the offshore gas, it is very important to look further afield for additional markets.
Figure 5: Northern Territory Gas Demand 2003 - 2020 - Median Case

Figure 6: Northern Territory Gas Demand 2003 - 2020 - High Case
4 QUEENSLAND

The market for gas throughout Queensland faces some uncertainty as current supplies may not be sufficient to meet projected demand and the augmentation of electricity generating capacity. Gas and coal compete as fuels for electricity generation, with coal seam methane being actively promoted by companies such as Boral, Transfield and Tri-Star Petroleum.

Central and south eastern Queensland are well served with pipeline infrastructure, although with some immediate capacity limitations into Brisbane. Mt Isa has recently been connected to the Cooper Basin by a pipeline from Ballera. As a result, Timor Sea gas could enter these regions of the Queensland market though Mt Isa by means of gas exchanges, swaps or trades, provided it was price competitive.

This report primarily addresses the markets to which relatively easy access can be gained and where there appear to be significant opportunities for the entry of Timor Sea gas, such as Mt Isa and to a lesser extent, Townsville. South east Queensland does represent another market, particularly for new gas fired power generation. Entry to this market, against competition from existing Bowen/Surat and Cooper/Eromanga gas will be difficult, since entry prices will have to be low to provide price differentiation against those established sources. Coal seam methane also represents a threat to both Timor Sea and Papua New Guinea gas because of its abundance, relatively low production cost and its proximity to Queensland markets (especially Gladstone).

It is very important for producers, pipeline owners and traders to ensure that gas is competitive against new coal fired generation. It has to be recognised that modern coal fired generators have very good turn down capabilities, acceptable low load efficiencies and fast response times from a standby mode, particularly when compared with combined cycle gas turbines. If gas firing is to be limited to peak and shoulder generation, then the cost of pipeline transportation will have a significant influence, since peak pipeline capacity has to be booked, but may only be used for short periods of time. Where linepack is available, pipeline operators can offer peaking services, but these become increasingly difficult to provide when the pipeline reaches capacity.

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12 Private communication with major coal seam methane exploration and development companies
4.1 Queensland Electricity Market

In its recent Statement Of Opportunities (Executive Summary), dated 31 March 1999, the National Electricity Market Management Company Limited (NEMMCO) analysed the electricity demand in all eastern states and assessed required generating capacity to ensure adequate reserves at times of peak demand. The study was based on growth rates predicted by the National Institute of Economic and Industry Research.

The outcome of the NEMMCO report on the electricity demand growth for Queensland is summarised in Figure 7.

Figure 7: NEMMCO Projections of Electricity Demand and Reserves for Queensland 1999-2009
Source: NEMMCO Statement Of Opportunities (Executive Summary), 31 March 1999

In respect of new generating capacity in Queensland, the NEMMCO report assumed new generators or interstate connections as set out in Table 2.

<table>
<thead>
<tr>
<th>Project</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>QLD - NSW Interconnector</td>
<td>AC interconnection between Queensland and New South Wales</td>
</tr>
<tr>
<td>Directlink</td>
<td>DC interconnection between Queensland and New South Wales</td>
</tr>
<tr>
<td>Oakey Gas Turbine</td>
<td>2 x 138 MW diesel fuelled gas turbines</td>
</tr>
<tr>
<td>Callide</td>
<td>2 x 420 MW coal fired generators</td>
</tr>
</tbody>
</table>

Table 2: Queensland Electricity Market - Committed Generation and Interconnect Projects
Source: NEMMCO Statement Of Opportunities (Executive Summary), 31 March 1999

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Demand growth and the commitments for new generation suggest that there is little room for gas fired generation in Queensland. This may change if the Transmission Use of System (TUOS) charges levied by Powerlink are altered to include more robust location signals\textsuperscript{14}. This will permit embedded gas fired generators to compete on equal terms with remote coal fired stations. However, I believe that significant opportunities exist for the use of gas in a closely coupled\textsuperscript{15} gas fired co-generation plant associated with mineral processing.

Coal is the preferred fuel for a number of generation proposals raised by developers. Potential new plants based on coal and gas are listed in Appendix C.

4.2 Mount Isa

Mt Isa represents the most accessible market for Timor Sea gas outside the Northern Territory. Mt Isa is also connected by gas pipeline to the Cooper Basin. This connection, even though it is of modest size (841 km of 323 mm diameter) would be able to deliver a maximum of about 35 PJ at 100% load factor. However, the pipeline represents an opportunity for gas to be back-hauled to Ballera in the Cooper Basin.

Provided suitable contractual arrangements can be developed, an amount of up to 70 PJ of Timor Sea gas can be delivered to southern and eastern markets. This could consist of up to 35 PJ into Mt Isa from Timor Sea to back out gas from the Cooper Basin and a further 35 PJ transported by reversing the pipeline’s flow from Mt Isa to Ballera. As a result, the connection to the Mt Isa “hub” is most important. The larger the potential load in the Mt Isa region, the more gas (within pipeline capacity limits) can be delivered from the Timor Sea to other markets by trading. Alternatively, the market growth is captured by Timor Sea gas.

The gas market in the Mt Isa region is directly associated with commodities - gold, copper, nickel and zinc mining and processing - and fertiliser manufacturing. As a result, market growth will be dependent upon international competitiveness of the mines, their infrastructure and energy price sensitivity. In the analysis of that market, the report addresses only those mines, processing facilities and power stations that are currently feasible and will be supplied with natural gas from the Cooper Basin. Clearly, there are more opportunities for growth, but because of the difficulty in quantifying them, they have not been included in this assessment.

The potential market for gas in the Mt Isa region is illustrated in Figure 8.

\textbf{Figure 8: Projected Gas Markets in Mt Isa Region 2003 - 2020 (minimal long-term growth scenario)}

Source: M. J. Kimber Consultants Pty. Ltd.

\textsuperscript{14} A review of TUOS structure has recently been completed by NECA.  
\textsuperscript{15} “Closely coupled” implies a good match between gas turbine power, exhaust heat output, steam requirements and in-plant electricity demand.
4.3 Townsville

Townsville is not supplied with natural gas and represents the largest untapped market in eastern Australia. The region contains extensive mineral deposits with associated processing plants. There are also opportunities for the development of co-generation and combined cycle plants in association with mineral processing industries.

A very significant opportunity is Queensland Nickel (QNI) which requires large quantities of low grade steam that could be economically produced from a co-generation facility. The economics of most projects in Townsville are dependent on the base load electricity produced. Given the uncertainties of the Queensland electricity market, the QNI project needs competitively priced gas.

Other proposed generating stations are in the same situation, including that being proposed by Stanwell. This report acknowledges these uncertainties and has adopted a conservative approach by indicating a modest demand that is very dependent upon landed price of gas. The forecast market is illustrated in Figure 9.

![Forecast Townsville Gas Demand](image)

*Figure 9: Projected Gas Markets in Townsville 2003 - 2020 (minimal long-term growth scenario)*

Source: M. J. Kimber Consultants Pty. Ltd.
4.4 South East Queensland

The south east Queensland market contains the load centres of Brisbane, Gladstone and Rockhampton. This market consumes approximately 48 PJ per year, made up of Brisbane - 27 PJ per year, Gladstone/Rockhampton 21 PJ per year.

The estimated demand in south east Queensland is shown in Figure 10. Proposals abound to use gas for mineral processing and power generation in this region. This observer has noted that few, if any, have been developed within the time schedule originally predicted, primarily due to an inability to match energy price and supply. While the Cooper/Eromanga Basin has significant amounts of uncontracted gas, a combination of well head price and relatively high pipeline tariffs impede its entry into the market for electricity generation.

As a result, I have not included the south east Queensland market directly into the potential market for Timor Sea gas. In effect, I am assuming that the south east Queensland market is a component of the 35 PJ per year load delivered to Ballera and/or a component of the market from the gas swaps or exchange mechanisms arranged through Ballera and Wallumbilla.

**Figure 10: Estimated Gas Demand in SE Queensland 2003 - 2020**

Source: M. J. Kimber Consultants Pty. Ltd.
5 SOUTH EAST AUSTRALIA

This chapter covers the south east Australian market - the States of South Australia, New South Wales and Victoria. Tasmania has not been included, though the concept of mainland or Bass Strait natural gas reaching that market is not new. The comments on Victoria are sufficient to cover Tasmania.

Accordingly, the south east Australian market is defined primarily on the population and industrial belt. This covers north of Newcastle in New South Wales to Sydney and Melbourne and around to Adelaide. This area is the biggest natural gas market in Australia.

Since the 1970’s the concept of North West Shelf gas being the natural gas supply for south east Australia has been considered. However, the distances are great and the real contenders are Timor Sea, Papua New Guinea and the Gippsland Basin.

5.1 New South Wales

Base gas demand in New South Wales has been quite static in the last few years, with the only significant increase due to the commissioning of the Smithfield co-generation facility. However, there are two drivers that may alter this state of affairs. Firstly, the construction of the Eastern Gas Pipeline (EGP) will give the New South Wales market access to a second source of supply, and secondly, the oversupply of electricity generating capacity should be taken up by demand growth by about 2005. This will leave the way open for gas fired generation - initially for peak and shoulder generation.

The re-powering of Munmorah power station with up to 500 MW of combined cycle gas turbine generators may provide the first major opportunity for large scale gas fuelled electricity generation in New South Wales. International requirements for compliance with reduced greenhouse gas emissions may also influence the increased use of gas for electricity generation and as a substitute for coal. On the other hand, electricity imports from Queensland and Victoria may limit capacity growth in New South Wales.

Figure 11 shows gas demand predictions for New South Wales from 2003 to 2020.
South Australia

Gas demand in South Australia has been declining in the late 1990’s as a result of increased imports of electricity from Victoria. South Australia has experienced price reductions for electricity of up to 20% due to the interconnection and to timing differences in peak demands.

There is now an expectation that market supply will grow by the commissioning of the proposed Pelican Point 500 MW Combined Cycle Gas Turbine (CCGT) generating station in 2001. Some of the contracts for the supply of low priced electricity from Victoria will also expire at about the same time, providing an opportunity for local generation to increase.

The most likely gas demands from 2003 to 2020 in South Australia are illustrated in Figure 12. This forecast differs from that originally published in the report by ACIL because of a differing perspective on growth of gas fired generation and the date of retirement of the Playford Power Station fuelled by Leigh Creek coal. The ACIL forecast is contained in Appendix B.
5.3 Victoria

Victoria is not considered to be a potential market for Timor Sea gas. Victoria is well served by Gippsland and Otway Basin gas at prices sufficiently low to make significant gas trading and exchange from the Timor Sea sub-economic. As a result, this report does not address the market for gas in Victoria.

5.4 Summary of south east Australian market

As follow-up to a pipeline built from Darwin to Mt Isa and Townsville, it is reasonably certain that Timor Sea gas will penetrate south east Australia. How and when is not clear.

I have included this market into the median and potential market cases for Timor Sea gas only to the extent that the market is a component of the gas flows to Ballera and the gas trading originating in Queensland. I have discounted Victoria as a market for Timor Sea gas because of the reserve levels and future expectations of the Gippsland and Otway Basins.

In the longer term, this assessment will need to be re-appraised. ACIL concluded that with the long term depletion of the Cooper Basin, south east Australian opportunities could arise from 2008 (or 2010 if gas from Papua New Guinea reached Australia). Arthur D Little concluded that the opportunities in south eastern markets could arise after 2020.
Gas supplies to the Northern Territory are presently limited, so cannot accommodate any significant growth in demand. In the medium term, the supplies are likely to fail to sustain the existing demand.

To ensure that the Northern Territory’s growth can continue, new sources of gas must be found to augment the gas supplies from the Amadeus Basin. It is in this context that the development of Timor Sea gas and its availability to Top End markets at world competitive prices are essential ingredients for growth of the Northern Territory.

This chapter reports on the Amadeus Basin and also covers the four Timor Sea gas resources - Bayu-Undan, Greater Sunrise, Evans Shoal and Petrel/Tern.

6.1 Amadeus Basin

There are presently two producing oil and gas fields in the Amadeus Basin - Palm Valley and Mereenie. Gas from these two fields is used in Alice Springs, Yulara, Tennant Creek, the Katherine area, McArthur River Mine and Darwin, mostly for electricity generation. In addition, there is a small, undeveloped gas field called Dingo.

Palm Valley gas field is located 120 km west of Alice Springs and is operated by Magellan Petroleum in joint venture with Santos and Kufpec. The field was discovered in 1965 and began commercial gas production in 1983 to supply natural gas, via pipeline, to the Alice Springs power station. Following the completion of the 1,600-kilometre pipeline from the Amadeus Basin to Darwin in November 1986, both Palm Valley and Mereenie fields have been supplying gas to the northern regions of the Territory.

Average production rates for Palm Valley during 1998 were around 25,500 GJ per day. Cumulative production to June 1998 was 110 PJ. Proved and probable gas reserves as at November 1998 were estimated at over 290 PJ.

A total of 255 PJ of gas from Palm Valley is contracted for supply to the Northern Territory Power and Water Authority (PAWA), a Government-owned statutory authority. Gas reserves in Palm Valley are understood to be fully committed to existing contracts. Gas delivery rates in the longer term are being assessed.

Mereenie gas/oil field is located 240 kilometres west of Alice Springs and is operated by Santos in joint venture with Magellan. The field was discovered in 1964 and began commercial oil production in 1984. Gas produced concurrently with oil is used to maintain pressure in the oil reservoirs, and about 17,500 GJ of gas per day enters the Amadeus to Darwin gas pipeline.
Cumulative gas production from Mereenie to June 1998 was 94 PJ. Proved and probable gas reserves as at November 1998 were estimated at over 440 PJ. A total of 165 PJ from Mereenie is contracted for supply to PAWA for power generation.

Proved and probable reserves in the Palm Valley field have been downgraded in recent years. At the same time studies of the Mereenie field have proven additional reserves. Nevertheless, the current estimates of uncontracted natural gas reserves in the Amadeus Basin are not sufficient for major energy using operations. Incremental supply to PAWA will be required and PAWA is keen to diversify its sources of supply. Without an alternative gas supply, potential large gas users such as the Nabalco bauxite/alumina project will not have the security of supply to justify investment in gas infrastructure.

Without Timor Sea gas, onshore gas demand growth (reliant upon Amadeus Basin reserves) will be incremental, dependent upon population growth and the mining industry’s demand for gas.

On the other hand, natural gas from Timor Sea is not likely to lead to the closure of the Amadeus Basin gas fields. Natural gas will continue to be provided to the Alice Springs region and to new markets in the Northern Territory and interstate.

6.2 Bayu-Undan

6.2.1 Description of Fields

The Bayu-Undan gas/condensate field is located within Area A of the Timor Gap Zone of Cooperation (ZOCA) approximately 500 km north west of Darwin and 300 km southeast of Kupang on the island of Timor. The ZOCA is jointly administered on behalf of Australia and Indonesia by the Timor Gap Joint Authority with offices in Jakarta and Darwin.

The field straddles Production Sharing Contract (PSC) Areas 91-12 and 91-13. Field dimensions are generally 25 km long and 12 km wide. The discovery well (Bayu-1) was drilled in PSC 91-13 in 1995 and another well (Undan-1) was drilled in PSC 91-12, also in 1995, confirming a common gas-condensate accumulation with the same gas-water contact.

A total of 10 wells have been drilled within the Bayu-Undan area. A total of 15 drill stem tests were conducted in different zones in 6 of the wells. As a result of detailed evaluation and modelling studies, the field has been determined to contain proven plus probable reserves of approximately 400 million barrels of condensate and liquefied petroleum gas and 3.4 trillion cubic feet of gas.
6.2.2 Ownership

Indonesia and Australia as agreed in the Timor Gap Treaty, own the gas and gas condensate resources of Bayu-Undan in equal shares. The current shares of each contractor in their respective PSC areas are shown in Table 3.

<table>
<thead>
<tr>
<th>PSC 91-12:</th>
<th>PSC 91-13:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phillips Petroleum 91-12</td>
<td>Phillips Petroleum Co ZOC</td>
</tr>
<tr>
<td>Santos</td>
<td>Phillips Petroleum Timor Sea</td>
</tr>
<tr>
<td>Inpex</td>
<td>Kerr-McGee (Oryx)</td>
</tr>
<tr>
<td>Petroz/Emet</td>
<td>British-Borneo</td>
</tr>
<tr>
<td>Total 91-12</td>
<td>Total 91-13</td>
</tr>
</tbody>
</table>

Table 3: Ownership of Bayu-Undan Fields

The initial Bayu-Undan Unit participating interests, as independently determined by DeGolyer and McNaughton, are approximately 55.2 percent for PSC 91-12 and 44.8 for PSC 91-13. Based upon this initial determination (and subject to a single re-evaluation within one year after commercial production commences), the individual participating interests are shown in Table 4.

<table>
<thead>
<tr>
<th>Participating Interests in Bayu-Undan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phillips Petroleum interests</td>
</tr>
<tr>
<td>Santos</td>
</tr>
<tr>
<td>Inpex</td>
</tr>
<tr>
<td>Kerr-McGee (Oryx)</td>
</tr>
<tr>
<td>Petroz / Emet</td>
</tr>
<tr>
<td>British-Borneo</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

Table 4: Participating Interests in Bayu-Undan

6.2.3 Development Plan

Preliminary engineering for an upstream (liquids recovery / lean gas recycle) project was completed in late 1998. The US$1.4 billion upstream project will include a drilling, production and processing platform that will be bridge-linked to a compression, utilities and accommodation platform. Water depth in this area is approximately 80 metres. Other key facilities will include an unmanned wellhead platform, drilling of 16 initial phase I wells, and a floating storage and off-loading facility handling condensate, propane and butane as separate products. Design production rates for this facility are 1.1 billion cubic feet per day of gas, 69,000 barrels per day of condensate, 24,000 barrels per day of propane, and 20,000 barrels per day of butane.

A draft development plan for the upstream project was prepared by the project participants and has been reviewed by the Timor Gap Joint Authority and the resource departments of Indonesia and Australia. Given timely receipt of approvals from project participants and governments and the resolution of several key tax and fiscal issues, liquids production is expected to commence in 2003.

While Bayu-Undan gas is liquids-rich, most of the value of this resource to the contracting nations and the project participants will be captured through exploitation of its gas reserves. Consequently, current efforts are focused on the simultaneous development of both its liquids and gas resources.
6.2.4 Markets

Marketing of petroleum produced from Bayu-Undan will be in accordance with the Timor Gap Treaty, the Petroleum Mining Code, and the relevant Production Sharing Contracts. It is expected that condensate and LPG products will be directed primarily to established fuel and petrochemical markets in Asia.

Early concepts for marketing of Bayu-Undan gas involved the production and sales of LNG. Due to the recent economic downturn in the major LNG importing nations of Southeast Asia, expectations for a near-term market for new LNG supplies have diminished measurably. In order to assure the earliest possible development of these large gas resources, several project participants redirected their efforts during 1998 toward developing a near-term domestic market for Bayu-Undan gas with initiation of gas sales beginning in 2003. However, the project participants will continue to evaluate LNG markets and believe Bayu-Undan is well positioned to capture such markets when they re-develop.

Due to unfavourable water depth, geophysical and seismic conditions associated with the Timor Trough, delivery of gas via pipeline from ZOCA is limited to locations in northern Australia. A potentially large foundation market for gas is available in the Northern Territory based on a mix of utility and industrial customers that in the aggregate constitute sufficient demand to enable the construction of a pipeline from ZOCA to Darwin. The project proponents believe such a pipeline could be the first stage of a larger regional gas gathering and transportation infrastructure, which would encourage further exploration and support further resource development in gas-rich ZOCA and the central Timor Sea area and gas market development throughout the region. Such regional infrastructure would also enable the development of currently non-commercial discoveries of gas in the Timor Sea.

Sales of dry gas from the upstream facilities to foundation customers are expected to grow from approximately 50 PJ per year in 2003 to over 100 PJ per year in 2010. Additional customers are expected to contract the remainder of the gas from Bayu-Undan, possibly as early as 2005/06, for 15 to 20 years of production.

Phillips Oil Company Australia has moved to acquire a site on Wickham Point near Darwin which would be the site for initial gas processing or distribution to other domestic markets. Environmental approvals from both the Northern Territory and the Commonwealth governments have been received for a 3 million tonnes per year LNG project originally proposed for this site. Phillips has also applied for pipeline licences from the field to the site and discussions necessary to the issuance of such licences have been completed. Acquisition of this site, including clearances under applicable native title and Aboriginal land rights statutes, is nearing completion.
6.3 Greater Sunrise - Evans Shoal

6.3.1.1 Description of Greater Sunrise

The Greater Sunrise Area is predominantly in Retention Lease NT/RL2, located in Australian territory some 450 km north-west of Darwin, with Indonesian territory immediately to the north and the Timor Gap Zone of Cooperation immediately to the west.

Initial discovery wells at Sunrise and Troubadour were drilled in 1974 and 1975. Following conclusion of the Timor Gap Treaty, exploration resumed with the Loxton Shoals well in August 1995, which confirmed the presence of a world-class gas-condensate field approximately 70 km long by 25 km wide.

Further wells at Sunset (October 1997) and Sunset West (April 1998) revealed the extension of the field into the adjoining Zone of Cooperation PSC 95-19. Together with a sixth well at Sunrise-2 (May 1998), these results led to the resource being upgraded to an expected scope for ultimate recovery (P50 confidence level) of 7.8 trillion cubic feet of gas and 281 million barrels of condensate. Up to 10% of the reserves could be in the Zone of Cooperation Area A (ZOCA).

6.3.1.2 Description of Evans Shoal

The Evans Shoal field is located some 290 km north-west of Darwin, and is entirely within Australian territory in Permit NT/P48. The Evans Shoal-2 well, drilled in March 1998, confirmed the presence of a very substantial dry gas field. Samples showed a gas composition of primarily methane with 28% CO₂ and inert gases. Whilst the recoverable gas volume is the subject of ongoing studies, recoverable hydrocarbon gas estimates range between 5.6 and 10.5 trillion cubic feet. The suggested estimate being used for planning purposes is 7.7 trillion cubic feet of gas.

Evans Shoal is one of the largest of the gasfields in the Timor Sea, and being located 290 km from Darwin, is one of the closest to landfall. It is also strategically located to be a component of a gas gathering system in the Timor Sea region.

6.3.2 Ownership

Participating interests in the several titles and the ZOCA Production Sharing Contract areas are shown in Table 5 below. Phillips became a participant for Greater Sunrise through the acquisition of the interests of BHP in April 1999. Woodside is the operator of all three titles covering Greater Sunrise.

<table>
<thead>
<tr>
<th>Area</th>
<th>Title/PSC</th>
<th>Woodside</th>
<th>Shell</th>
<th>Phillips (after purchase from BHPP)</th>
<th>Timor Sea Petroleum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greater Sunrise</td>
<td>NT/RL-2</td>
<td>66.67%</td>
<td>25%</td>
<td>8.33%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>NT/P55</td>
<td>33.33%</td>
<td>33.33%</td>
<td>33.33%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>ZOCA 95-19</td>
<td>33.33%</td>
<td>33.33%</td>
<td>33.33%</td>
<td>-</td>
</tr>
<tr>
<td>Evans Shoal</td>
<td>NT/P48</td>
<td>-</td>
<td>85%</td>
<td>-</td>
<td>15%</td>
</tr>
</tbody>
</table>

Table 5: Ownership of Greater Sunrise and Evans Shoal Fields

The Evans Shoal permit area is held by Shell and Timor Sea Petroleum; and is in Northern Territory administered waters. Shell is the operator of NT/P48.

21 Source: NAGV and Timor Sea Petroleum.
6.3.3.1 Development Plan for World-scale LNG Project

In May 1997 Woodside and Shell formed the Northern Australia Gas Venture (NAGV) as a 50:50 joint venture. The immediate purpose was to conduct a feasibility study into the production of gas from Greater Sunrise and Evans Shoal for an onshore world-scale LNG plant (with production of 7.5 million tonnes per annum). This was to be linked to a domestic gas supply to customers in the Northern Territory and beyond. The feasibility study covered markets, engineering, environmental and economic aspects of the proposed project and was completed in December 1998.

This complete project would require reserves of 11 trillion cubic feet to underpin long-term sales contracts. As has been noted above, the Greater Sunrise and Evans Shoal gas fields together contain recoverable resources far exceeding this amount.

The preliminary field development plan for Sunrise is based on a single fixed platform in about 160m water depth. Initial wells will be drilled from the platform, with subsequent wells tied back from sub-sea manifolds extending to as far as 30 km from the platform and down to 500m water depth. The platform will include dehydration, processing and gas compression.

A 40 inch pipeline forms the base case for transport to shore. A number of different routes have been considered based on surveys of seabed conditions. The preferred route passes to the west of Melville Island, requiring a line length of 490 km. Evans Shoal gas will join the main trunkline from Sunrise to Darwin by means of a short spur line. The possibility of also gathering other third party gas has not been excluded.

Glyde Point, about 50 km north east of Darwin has been found to be suitable as the site for the onshore plant. This will comprise condensate separation, two LNG production trains, LNG storage tanks and a 2.9 km jetty to provide access to sufficient water depth for LNG carriers without dredging. The site would also incorporate a plant to process gas for delivery by pipeline to customers in northern Australia.

Extensive consideration has been given to the infrastructure requirements of the Glyde Point development, and to the possibility for other energy intensive industries to be located nearby. Woodside submitted a Notice of Intent/Referral Document for the development of Glyde Point in late 1998, and has been advised of the guidelines to follow in preparing a full Environmental Impact Statement (EIS).

The capital cost of the entire development (excluding LNG tankers) is estimated to be some $10 billion. The feasibility study concluded that the project was technically feasible, but that ultimate success would depend upon the capture of markets and project economics.

6.3.3.2 Development Plan for Stand-alone Domestic Gas Project

In support of NAGV both the Greater Sunrise, and the Evans Shoal joint ventures, are in the process of carrying out feasibility studies with respect to the economics of development on a stand-alone basis to supply domestic gas requirements. Given the very large recoverable gas positions of both fields, these development scenarios are seen as being complementary to the longer term development of a world scale LNG plant.
6.3.4 Proposed Markets

Proposed markets for LNG production are in Asia excluding Japan. Since the feasibility study commenced, expected growth in demand for LNG in Asia has substantially declined and competition in the region has increased. Nevertheless, opportunities may still be realised, but possibly later than originally thought.

NAGV participates in and is fully supported by Australia LNG, the recently formed LNG marketing vehicle that brings together BHP Petroleum Pty Ltd, BP Developments Australia Pty Ltd, Chevron Corporation, Japan Australia LNG (MIMI) Pty Ltd, Shell Development (Australia) Pty Ltd and Woodside Energy Ltd. Australia LNG will be able to offer flexible commercial terms to LNG customers backed up by a diverse range of gas sources to the north and west of Australia. NAGV will continue to actively pursue LNG markets through Australia LNG.

In addition, NAGV has been active in seeking customers for domestic gas near Darwin, in the Northern Territory and in Queensland. Potential markets are described in chapters 3 and 4 of this report. It is clear that domestic gas demand in these areas has the potential to grow strongly. However, domestic gas customers have clearly signalled their reluctance to become dependent on the progress of an LNG development.

Shell and Woodside recognise the enormous impact that the availability of large quantities of competitively priced natural gas would have on the development prospects for Darwin, the Northern Territory and Queensland. Accordingly, NAGV is now working on an alternative, smaller-scale development to supply domestic gas only. The very substantial resources available to NAGV make it possible to commit to a long-term supply to domestic customers and still undertake LNG development in the future.

The prime purpose of these alternative studies of Greater Sunrise and Evans Shoal is to determine the viability of a development targeting major new gas-sourced, export based industries in the Northern Territory and Queensland.
6.4 Petrel-Tern Fields

6.4.1 Description of Field

The Petrel field is located in Australian territorial waters, approximately 250 km west of Darwin on the Northern Territory / Western Australia sea bed border in the Bonaparte Basin, permits N/RL1 and WA-6-R. Since the drilling of the discovery well (Petrel) and associated relief well (Petrel-1A) in 1969-70 a further 5 wells have been drilled on the structure, confirming the presence of a significant gas resource. Rates up to 34 million standard cubic feet per day have been recorded on drill stem tests.

The Tern field is located in permit WA-18-P, approximately 300km west of Darwin and 60km south west of the Petrel field. The Tern-1 discovery well was drilled in 1971 and flowed gas at a mechanically restricted rate of 7 million standard cubic feet per day. A further 3 successful appraisal wells have been drilled on Tern with all wells encountering gas. The most recent well, Tern-5 was drilled in 1997/98 and flowed gas at 15 million standard cubic feet per day.

The Petrel and Tern joint ventures have recently completed a review of gas-in-place and reserves in both fields. Results of this work indicate combined proved and probable resources in excess of 1 trillion cubic feet with significant upside potential in the Petrel field.

6.4.2 Ownership

Ownership of the Petrel and Tern permit interests is shown below:

<table>
<thead>
<tr>
<th>Company</th>
<th>Petrel (NT/RL 1, WA-6-R)</th>
<th>Tern (WA-18-P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Santos Group (Operator)</td>
<td>50.49%</td>
<td>70.00%</td>
</tr>
<tr>
<td>Bonaparte Gas and Oil Pty Ltd</td>
<td>44.51%</td>
<td>30.00%</td>
</tr>
<tr>
<td>Boral Energy Bonaparte Pty Ltd</td>
<td>5.00%</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 6: Ownership of Tern and Petrel Fields

Santos has entered into agreements with Bonaparte Gas and Oil Pty Ltd ("Bogas") to acquire the Bogas interests.

6.4.3 Development Plan

The Petrel and Tern joint ventures have recently completed a preliminary development plan, which contemplates what Petrel and Tern field development scheme would be required for supply of significant quantities of gas to the Northern Territory domestic market.

The first phase of the development plan proposes the initial development of the Petrel field via a subsea development with unmanned offshore facilities. Gas would initially free-flow from the Petrel field to an onshore gas plant where the gas would undergo a minimum amount of conditioning to achieve sales quality, then compressed and exported into the existing Amadeus-Darwin pipeline system.
6.4.4 Proposed Markets

Development of the Petrel and Tern fields is specifically targeted to supplying existing NT markets described in chapter 3 of this report. Sufficient reserves have been defined to enter into long-term arrangements with these targeted customers.

The Petrel/Tern project is seen to have numerous positive attributes, including the following:

- This project is entirely within Australian waters.
- There will be essentially one owner who is intent upon project commercialisation. Hence, no intra joint venture issues are expected to exist.
- Development is not contingent on factors such as an LNG project, development of additional incremental downstream domestic markets, or development of additional upstream projects. The project will likely also support additional incremental market development in the future.
- It is believed that the pipeline to shore could be a part of a larger regional gas gathering and transportation infrastructure, which would encourage further exploration and support further resource development in the offshore NT region, including ZOCA and the “Greater Timor Sea”.
7 GAS SUPPLY IN EASTERN AUSTRALIA
- CURRENT & FUTURE PROSPECTS

Eastern Australia has been supplied with commercial quantities of natural gas for a relatively short period. The Gippsland, Surat and Cooper Basins all came on stream in the late 1960s and all eastern mainland states have depended upon those sources since then. As a result, it is prudent to consider the reserve status of those basins and their future prospects to ensure that supplies of gas from other sources, such as the Timor Sea can be considered in context. This chapter deals with those basins and also considers new sources, such as coal seam methane and conventional gas from Papua New Guinea.

7.1 Bowen - Surat Basin

The Bowen - Surat Basins (including the Denison Trough region) have modest reserves and have been producing gas for supply to Gladstone and Rockhampton since 1989 and Brisbane since 1969. As a result, the remaining reserves are small but are sufficient to meet current contractual demands until 2005-2007. There is some scope for expansion, and recent finds by OCA/Santos in the Denison Trough region indicate that more reserves are able to be delineated, but they are expected to be inadequate to provide substantial supplies for south east Queensland. Other exploration and production companies, such as Petroz, are also having some success in proving up new reserves in parts of the Surat Basin. Currently, about half the gas supplies for south east Queensland are provided from the Cooper Basin.

7.2 Bowen Basin - Coal Seam Methane

The most significant resource available in Queensland to underpin the growing gas market is that of coal seam methane. However, it has to be considered in the context that it is under-developed and will need substantial expenditure to bring it into production, but the potential rewards are great. There has been significant exploration in two major regions - Fairview and Durham Downs in the south Bowen Basin and Moura in the north (see Figure 13). Each region is producing commercial gas quantities on a continuous and reliable basis - up to 6 TJ per day from Fairview, 3 TJ per day from BHP's Moura fields and 3 TJ per day from OCA's Moura fields.
An expanded drilling program will almost certainly produce significantly more gas. For example, the structure on which the existing Fairview wells have been drilled is very extensive and a drilling program of another 150 to 170 wells could easily be encompassed within the drill spacing of 1 km. Given the homogeneity of the gas producing coal seams in terms of gas content, permeability and thickness, it has been suggested that there is a 90% probability that, over the whole area of 486 km² being analysed, the recoverable reserves would easily approach 1 trillion cubic feet. The recovery of this amount would probably require up to 170 wells.

Given the large scale of the resource and a few successful developments already in place - particularly in the Comet Ridge and Durham Downs areas - it is likely that a significant proportion of the Queensland's gas supply could come from coal seam methane sources. In this context, it is worthwhile to note that about 20% of the gas supply for western United States comes from coal seam methane. I would expect that Timor Sea gas will have to compete against coal seam methane supplies in the Queensland market, with coal seam methane having proximity to Gladstone and Brisbane. In addition, there are proposals for the construction of a pipeline from the Bowen Basin to transport coal seam methane to Townsville.

7.3 Papua New Guinea

The reserves of gas in the highlands of Papua New Guinea are large and those in the Hides and Kutubu fields have recently been amalgamated by the developers, including Chevron, Exxon and Oil Search (more recently, Woodside and Santos have acquired a significant holding in Oil Search and its PNG leases) to provide enough reserves to underpin the throughput necessary to support the construction of a pipeline from Kutubu to Townsville and Gladstone. Despite this reserve support, many of the original impediments to the development of this pipeline remain, such as assured markets of sufficient size, sovereign and environmental risk and landed gas price. This last issue - that of price - is very important, considering that the gas has to be shipped 2655 km and that, apart from the Kutubu field, the majority of gas comes from gas fields whose development cannot be supported by oil production.
7.4 Cooper Basin

In Santos’ 1998 Annual Report, the company reported that the 2P reserves in the Cooper Basin stood at 5160^2PJ, of which 2560^2PJ was uncontracted. This represents a significant quantity of gas, which can be delivered to Sydney, Adelaide, Mt Isa, Brisbane and Gladstone through established and relatively under-utilised pipeline systems. This puts the Cooper Basin producers in a very strong competitive position in respect of gas supplies from distant locations, such as Papua New Guinea and the Timor Sea.

7.5 Gippsland Basin

The Gippsland Basin can be described as relatively under-developed. However, that basin has sufficient reserves to support the Victorian market and a substantial proportion of the New South Wales market. Further exploration and development in the Gippsland Basin, particularly in the Kipper, Basker, Manta and Gummy fields is expected to reveal more reserves that will ensure continued supplies to south-eastern Australia.

7.6 Otway Basin

The reserves in both on-shore and off-shore Otway Basin are modest and while they will make some contribution to supplies to Victoria and south-east South Australia, they do not represent a serious competitive threat to supplies from other basins to those regions.

7.7 Summary on Possible Eastern Australia Gas Supplies

Currently, the Cooper/Eromanga and Gippsland Basins dominate supply to eastern Australia markets. The future of these basins will be a key factor for the potential timing of new gas supplies. Clearly the Cooper Basin has a longer life than is currently projected though supply growth may be limited. The Gippsland Basin has potential for growth and will become a new source of gas for the New South Wales market.

Because of proximity to the Gladstone and Brisbane markets, coal seam methane will emerge as a new competitive threat. It is not clear at this stage however, whether coal seam methane will supplement other supplies or dominate the market.

The big gas resources to the north are in the Timor Sea and Papua New Guinea. There may be a market for both - PNG in eastern Queensland and Timor Sea in western Queensland, South Australia and New South Wales. Alternatively, Timor Sea gas will be an important contributor to industrial development in the Northern Territory and Mount Isa, and also become a major new source of gas for eastern Queensland.
For northern Australia, there are a range of pipeline options that are dependent on the relative penetration into the Australian market by Timor Sea natural gas, Papua New Guinea natural gas and coal seam methane. The map shows all these pipeline options.

Both Papua New Guinea gas and coal seam methane have targeted the Townsville and Gladstone markets on the east coast of Australia, since each represents opportunities for large scale gas fuelled facilities for electricity generation and mineral processing. These large blocks of gas demand are essential for underpinning the necessary pipeline and infrastructure to make development of these supplies economic.

ACIL concluded that “it is clear that Timor Sea gas would be very competitive in Darwin, Gove and Mount Isa: and also Townsville if the PNG pipeline did not eventuate”. ACIL added that if PNG gas does not enter the market, there may be market opportunities in Townsville and Gladstone. I concur with these ACIL views on market opportunities.

ACIL also considered the pipeline options with Timor Sea gas exiting the Northern Territory to Mount Isa or from Alice Springs to Moomba. ACIL concluded that both options provide “access to South Australia and New South Wales with the Mount Isa route offering the additional opportunity of the Mount Isa market”. I see the best early opportunities being associated with the Mount Isa link.

I have reviewed the pipeline options contained in the ACIL report and have concluded that the most suitable location for entry of Timor Sea gas to southeastern markets is via Mt Isa. The initial termination point at Mt Isa provides the opportunity to continue a pipeline to Townsville if the demand is sufficient. Delivery of new gas to Mt Isa will also result in an ability to trade and swap gas into all markets that are linked by pipeline with Mt Isa. This includes Gladstone, Brisbane, Sydney and Adelaide.

I have also developed a pipeline tariff methodology that relies on low entry tariffs which significantly under recovers on costs in the early years. Appropriate returns are provided to the pipeline owner through market growth. Such a “tariff path” is acceptable under the current National Third Party Access Code for Natural Gas Pipelines.
8.1 Basic Assumptions for Pipeline Plans

This report uses the following criteria for pipelines using Timor Sea gas:

- The gas demand profiles will be as described in Section 3 above
- One gas price is assumed for Timor Sea gas delivered to Darwin and that gas price will escalate at 3%pa
- Development of offshore Timor Sea gas supplies to the Northern Territory and further afield will be sufficiently underpinned by liquids development, demand for gas in the Top End or LNG to allow the landed price to be low enough for market penetration.
- All gas transport tariffs escalate at 3% per year.
- Financial modelling to develop pipeline tariffs has been based on an unlevered nominal post tax return of 10% pa.
- The threshold price for delivered gas is low enough to meet the market’s expectations for mineral processing and electricity generation.
- Pipelines will be sized to meet the 10-year market expectations with minimum compression.
- Pipelines will operate at a maximum allowable operating pressure of 15.3 MPa.
- The estimated cost of pipelines has been based on recent pipeline construction in remote areas with minimum construction complexity.

8.2 Establishment of Gas Trading Hubs

At present Australia has no gas trading hub that handles significant quantities of gas. Some gas trading occurs at Wallumbilla (Qld), and contractual arrangements have recently been put in place to allow limited trading at Moomba. However, these represent a small beginning to what should become an active part of Australia’s emerging gas market.

The establishment of trading hubs will require the acceptance of new concepts and will represent a paradigm shift in the development and management of gas sales and contracting. Trading of gas, using storage, swaps, exchanges and put and call options, probably offer the most upside for the sales of gas from the Timor Sea into south eastern Australia.

Trading of gas and pipeline capacity is common practice in the United States and Canada, where several thousand trades are done each day on pipelines such as those delivering gas from Alberta to California. There is a fluid market because each pipeline connects a large number of gas producers to a large number of customers in many markets. In this context, the Australian situation can be described as embryonic, but with very good potential.
The increased numbers of producers, the arrival of several North American energy trading companies, and the requirements of the Australian Competition and Consumer Commission in its enforcement of the Trade Practices Act to limit joint marketing arrangements and exclusive dealing, are evidence of a changing environment. However, contractual and cultural bottlenecks still exist and these will have to be changed by commercial pressures, rather than regulatory action, to ensure a smooth transition to an open and transparent market.

It is likely that large energy trading companies will purchase tranches of gas and pipeline capacity. This will provide a buffer between producers and pipelines who want long term contracts to support financing and customers who want shorter term contracts with flexibility. The early development of Timor Sea gas will be heavily influenced by such commercial arrangements.

Although a large proportion of gas trades and swaps can be classified as derivatives, ultimately physical deliveries of gas have to be made. As a result, trading can only take place between sources and markets if there are pipeline interconnections. The network of pipelines proposed in this report provides those connections.

8.3 Overview of Pipeline Plan

As a result of a detailed analysis of pipeline costs and potential markets for Timor Sea gas, this report suggests that the target markets, in order of priority and access should be:

**Top End (rising to 60 PJ by 2005/6)**
- Shortfall in gas for electricity generation
- Nabalco alumina refinery
- Brown’s cobalt project
- Jabiluka/Ranger project
- Mt Grace magnesium smelter

**Mt Isa (rising to 70 PJ, including trading by 2010)**
- Supply of price competitive gas to Mt Isa region mineral projects
- Backhaul Mt Isa to Ballera for gas swaps into SE Queensland and South Australia.

**Townsville (rising to 50 PJ by 2005)**
- Power generation - peak, intermediate and base
- Mineral processing

The pipelines will be built in the following order, assuming gas is available in Darwin from the Timor Sea in 2003:

<table>
<thead>
<tr>
<th>Priority</th>
<th>Pipeline</th>
<th>In Service</th>
<th>Comment</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Mataranka to Nhulunbuy</td>
<td>2003</td>
<td>Initially, gas for Nhulunbuy will be back-hauled from Darwin on existing Amadeus Basin to Darwin pipeline.</td>
</tr>
<tr>
<td>2</td>
<td>Darwin to Mataranka</td>
<td>2004</td>
<td>Will take over supply to Nhulunbuy.</td>
</tr>
<tr>
<td>3</td>
<td>Mataranka to Mt Isa</td>
<td>2004</td>
<td>Supply to Mt Isa markets and for backhaul to Ballera.</td>
</tr>
<tr>
<td>4</td>
<td>Mt Isa to Townsville</td>
<td>2005</td>
<td>May not proceed if PNG gas or coal seam methane is more competitive.</td>
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</tbody>
</table>
The pipelines proposed for delivery of Timor Sea gas to markets are shown in Figure 14.

Figure 14: Pipeline Options for Gas Transport from the Timor Sea
Base map source: Australian Gas Association

Table 7 shows the lengths, sizes, capacities and tariffs (in 1999$ per GJ) that are likely to be used for transport of gas from the landfall for Timor Sea gas at Darwin.

<table>
<thead>
<tr>
<th>PIPELINE</th>
<th>LENGTH km (Note 1)</th>
<th>DIAM. mm</th>
<th>COMP STN</th>
<th>NOMINAL CAPACITY TJ/day (Note 2)</th>
<th>NOMINAL CAPACITY PJ/year</th>
<th>CAPITAL COST $mill</th>
<th>OP COST $mill/a</th>
<th>TARIFF $/GJ (1999) (Note 3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Darwin - Mataranka</td>
<td>400</td>
<td>610</td>
<td>1</td>
<td>400</td>
<td>146</td>
<td>244</td>
<td>5</td>
<td>0.264</td>
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<tr>
<td>Mataranka - Nhulunbuy</td>
<td>580</td>
<td>323</td>
<td>1</td>
<td>150</td>
<td>55</td>
<td>187</td>
<td>4</td>
<td>0.332</td>
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<tr>
<td>Mataranka - Mt Isa</td>
<td>965</td>
<td>508</td>
<td>2</td>
<td>360</td>
<td>131</td>
<td>490</td>
<td>10</td>
<td>0.653</td>
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<tr>
<td>Mt Isa - Townsville</td>
<td>900</td>
<td>406</td>
<td>2</td>
<td>165</td>
<td>60</td>
<td>365</td>
<td>7</td>
<td>0.713</td>
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<tr>
<td>Mt Isa to Ballera (Note 4)</td>
<td>0.500</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.500</td>
</tr>
</tbody>
</table>

Table 7: Pipeline Configurations and Tariffs

General Notes: Profile of throughputs for tariff determinations for all pipelines based on forecasts shown in Section 8.
MAOP of all pipelines: 15.3 Mpa.

Note 1: Includes 5% allowance over map distances.
Note 2: Capacities can vary significantly with compressor configuration and locations.
Note 3: Tariffs escalate at 3% pa.
Note 4: Applies to back haul only, say up to 35 PJ. If flow reverses, flow will be at forward haul rate ($1/GJ).
The estimated total tariff for delivery of Timor Sea gas to Townsville is $1.63/GJ for a total annual quantity of 54PJ. While this represents a significant impediment to market development in that area, an additional 40-50 PJ a year load in Townsville would reduce the pipeline tariff to around $1.00/GJ, which is the same as the PNG “postage stamp” tariff for the transport of PNG gas from the Australian border to Townsville and Gladstone.

The method used for determining haulage tariffs for long distance gas transmission pipelines has a significant influence on the market price for the gas. Tariffs are usually determined in such a way as to allow the pipeline owner to make reasonable returns on its investment, given the level of risks in market, supply, construction and operating environments. The National Third Party Access Code for Natural Gas Pipeline Systems is quite specific about the use of cost of service methodology for determination of haulage tariffs for periods as short as five years and most access arrangements that have been submitted to date have followed this guide. For green field pipelines, such as those delivering gas to southern markets from the Timor Sea, a much more market focussed tariff method has to be used.

As a result, the tariff method adopted in this report establishes long term tariff paths, which allow the entry price of gas to be as low as possible. Pipeline revenues can only increase as a result of market growth, so there is an incentive for the pipeline owner to react positively to market signals. The tariffs are also set to provide strong locational signals - that is, the cost of transporting gas to Mt Isa would be much lower than to Townsville. This approach differs from that applied to the pipeline from Papua New Guinea, where the “postage stamp” methodology has been used - that is, the price of transporting gas to Gladstone is the same as for Townsville. This means that cross-subsidies are inherent in the tariffs.

“Postage stamp” tariffs can give inappropriate economic signals. The electricity network transmission charge - the transmission use of system or TUOS - is an example of a postage stamp tariff that does not contain locational signals. Some Queensland companies have suggested that Timor Sea gas entering Queensland also be sold on a “postage stamp” basis. This would also significantly reduce the tariff to Townsville.

8.4 Conclusions on Pipeline Options

Analysis of the pipeline options shows quite clearly that Timor Sea gas would be competitive in the Top End (particularly Nhulunbuy) and Mt Isa. Pipeline extensions beyond Mt Isa are very sensitive to market demands and will only proceed if large blocks of gas load are available.
9  CONCLUSIONS

A review of the markets for Timor Sea gas and the associated pipeline infrastructure indicates that prospects for development of Timor Sea gas are high. Gas would come onshore from the following fields in Australian administered waters (unless specified otherwise):

- the Bayu Undan gas/liquids field in the Zone of Cooperation Area A (ZOC-A), or;
- the Greater Sunrise fields with up to ten percent in ZOCA or;
- Evans Shoal or;
- Petrel/Tern.

In the Northern Territory, gas would initially be supplied for power generation and mineral processing in Darwin and Nhulunbuy. Subsequently, Timor Sea gas could enter southern markets to augment and possibly replace Cooper Basin gas supplies in the Mt Isa region, and supply further east as far as Townsville. By trading and gas swaps from Queensland, supply could extend to other regions in southern and eastern Australia.

The recent purchase of BHP Petroleum’s share of the Bayu-Undan field by Phillips Petroleum, together with Phillips’ stated commitment to develop the resource, should improve the prospects of development.

Woodside and Shell have been joined by Phillips as co-venturers in Greater Sunrise, following Phillips’ acquisition of some of BHP’s interests in the Timor Sea. In expectation of improved international markets for liquefied natural gas (LNG), or strong growth of domestic markets, there are also good prospects for the development of the Greater Sunrise gas fields. Woodside and its partners have well advanced plans for the development of the Greater Sunrise and Evans Shoal fields.

The tyranny of distance that might have had an adverse effect on the development of both the Bayu-Undan and Greater Sunrise fields could perhaps be overcome by the establishment of a regional gas gathering infrastructure. By connecting Timor Sea gas fields and transporting the gas to Darwin, offshore development costs could be significantly reduced.

Evans Shoal, as one of the largest of the Timor Sea gas fields, located entirely within Australian waters in close proximity to Darwin (290km), may have a significant role to play as a possible foundation member of such a regional gas gathering scheme.

Santos has recently completed a detailed feasibility study of Petrel/Tern and reached an agreement to increase its ownership of these permits. The company is progressing the short-term prospects for development of this resource.

The challenge is to have sufficient market demand to justify the development of more than one field at a time. Clearly this will be an issue for regional developers to contemplate as the first commitments to supply gas from the Timor Sea are executed and decisions are made about the size and routing of pipelines to deliver that gas to domestic users.
The construction of a pipeline system between the Top End and Mt Isa will allow both physical and derivative trading of gas between the Timor Sea gas fields, and markets in South Australia, New South Wales and Queensland. Trading hubs are likely to be developed in Mt Isa, Ballera (Qld), Moomba (SA) and Wallumbilla (Qld). If gas supplies to Townsville from Papua New Guinea or coal seam methane do not proceed, then there may be an opportunity for Timor Sea gas to supply that market as well as other markets in eastern Queensland.

Another, and a most important ingredient to the successful development of Timor Sea gas, will be a clear recognition by gas producers and pipeline operators that the prices of their products - gas and transportation - will have to be competitive and also meet the market's expectations at the point of sale.

Growing the market for natural gas in northern Australia is the key to achieving the maximum potential of the Timor Sea gas fields. The availability of Timor Sea gas supplies to the Australian gas marketplace will signal the next stage of maturity of the Australian gas scene, where there will be an increasing number of buyers and sellers of gas, and a truly competitive market will begin to evolve.

The new era will represent a significant shift from the current Australian gas market structure, to a structure in which gas pipeline networks cater to a number of gas suppliers, traders and end use customers.

A supply of natural gas from the Timor Sea gas fields at world competitive prices will underwrite and strengthen Australia’s position in a global market for commodities and tradeable goods.

10 ACKNOWLEDGMENTS

I wish to thank members of the Timor Sea Consultative Group and officers of the Office of Resource Development of the Northern Territory Department of Mines and Energy for their contributions to this report and for their constructive criticism of the early drafts.
## APPENDIX A

### Timor Sea Consultative Group List of Members

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<th>Title</th>
<th>Contact Number</th>
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APPENDIX B
Market Projections by ACiL Economics

Northern Territory Forecast

Mt Isa Forecast

Townsville Forecast

Gladstone Forecast
Opportunities for Timor Sea Gas in Northern Territory & Queensland

Source: Acil Economics and Policy Ltd; Prospects for Timor Sea Gas in the Australian Market, November 1997
## APPENDIX C

### Potential New Power Generation in Queensland

<table>
<thead>
<tr>
<th>Proponent</th>
<th>Location</th>
<th>No. of Units</th>
<th>Total Station Rated Output MW (Generated)</th>
<th>Proposed Commissioning Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>AQC (Kogan Creek) Pty Ltd</td>
<td>Kogan Creek, Brigalow, Chinchilla Shire</td>
<td>1 or 2</td>
<td>800</td>
<td>Late 2002</td>
</tr>
<tr>
<td>InterGen</td>
<td>Millmerran</td>
<td>2</td>
<td>840</td>
<td>June 2002</td>
</tr>
<tr>
<td>Gibson Island Power Pty Ltd</td>
<td>Gibson Island Murarrie (^{(1)}) (^{(2)})</td>
<td>1</td>
<td>350</td>
<td>1st half 2001</td>
</tr>
</tbody>
</table>
| Tarong Energy and Entergy              | Adjacent Tarong Power Station         | 2            | 900                                      | Unit 1 - Mid 2002
|                                        |                                       |              |                                          | Unit 2 - Early 2003         |
| Bulwer Island Energy Partnership       | BP Bulwer Island \(^{(1)}\)           | 3            | 32                                       | July 2000                   |
| Stanwell Corporation                   | Townsville                            | 3            | 700                                      | July 2002                   |
| Stanwell Corporation                   | Koombooloomba Dam (Kareeya)           | 1            | 7                                        | January 2000                |
| Rocky Point Green Energy Project Pty Ltd | Woongoolba (near Beerleigh) \(^{(1)}\) | 1            | 30                                       | August 2000                 |

\(^{(1)}\) Application made to Energex.

\(^{(2)}\) Significant export to the Powerlink network possible.

Source: Powerlink - "Annual Planning Statement 1999".