Implications of emerging patterns in energy markets for the PNG Joint Venture

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Contents

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Introduction

1. Introduction

1.1. BACKGROUND – APPLICATION

1 The issue before the Australian Competition and Consumer Commission (Commission) in the present case is the application (the Application) for authorisation of a marketing joint venture by the ExxonMobil, Oil Search, MRDC, and Nippon Oil (the Participants). The Participants have formed a joint venture for the production of gas in Papua New Guinea (PNG) and they are seeking authorisation to market that gas via a joint venture within Australia. The Application therefore requires the Commission to consider the relevant market for analysing whether the proposed joint marketing arrangements should be authorised.

1.2. APPROACH

2 The Participants' project is further described in Section 2. In summary, the project involves the extraction of natural gas from fields in the Southern Highlands of PNG and the transportation of that gas to Australia.

3 This project represents a major infrastructure project in the Australian energy sector and would contribute to the process of development that has already been occurring in this sector following energy market reforms of the 1990s. Section 2 also highlights the substantial difficulties faced by the Project in securing foundation customers and loss of potential customers to other suppliers. The reasons for these difficulties are explainable in terms of the developments in the market and the expanded scope for competition that the Project faces. A narrative on these industry developments is provided in section 3 of this report. This historical record clearly demonstrates the continuing evolution of the energy sector, a key element of which involves the increasing interconnection between jurisdictions across eastern Australia in both gas and electricity, and the linkages between gas and electricity, with these linkages driven by developments such as government policies to reduce greenhouse gas emissions from the electricity generating sector.

4 The evolutionary nature of the energy sector and the development of competition across gas basins and across fuel sources will have implications for the issue of market definition. In this regard there have been two key decisions that are particularly pertinent to this present matter. These decisions emphasize the importance of the time dimension in market definition and the expansion that is occurring in energy markets:

- The first is the decision of the Australian Competition Tribunal (Tribunal) in *Re: AGL Cooper Basin Natural Gas Supply Arrangements (AGL Cooper Basin)*[1]*;* and
- The second decision is that of the Federal Court of Australia in Australian Gas Light Company (CAN 052 167 405) v Australian Competition & Consumer Commission (No 3) [2003] FCA 1525.

[1] *Re: AGL Cooper Basin Natural Gas Supply Arrangements* (1997) ATPR 41-593.

1.1.1 AGL Cooper Basin Natural Gas Supply Arrangements

5 This decision concerned the authorisation of an agreement for the sale of gas to Australian Gas Light (AGL) by the South Australian joint venture producers.

6 In this case the Tribunal noted that the effects of the conduct on competition occurred within markets that were expanding over time:

> In considering this expanding market, we specify three dated markets of interest: the market in 1986 [at the time of the initial authorisation], the market today, and the market in "the future" – perhaps ten or fifteen years hence. Quite obviously the geographic market is expanding over this time period, and the product market is also expanding, as we explain below.[2]

7 The Tribunal expanded on the remark concerning the product dimension of the markets by noting that natural gas is sometimes a substitute for and sometimes a complement with the production of electricity. Therefore, the Tribunal's references to the "natural gas market" must be understood in an extended sense to include electricity where it was appropriate.

8 The Tribunal then defined the markets with which it was concerned. It was concerned with three product markets: natural gas (understood in the extended sense noted above), transmission and reticulation. With respect to the natural gas market, the Tribunal considered three functional dimensions:

(i) exploration and development;

(ii) production and processing; and

(iii) distribution.

9 The Tribunal considered that the geographic dimension of the natural gas market had been expanding from NSW in 1986 to south east Australia (NSW, Victoria, South Australia and Southern Queensland) in 1997. In the opinion of the Tribunal, the "future market" for natural gas (perhaps around 2007 or 2012) would be Australia-wide, including offshore sources of gas in West Australia and the Northern Territory, and also possibly PNG.

1.1.2 Federal Court AGL decision

10 The Federal Court was required to assess whether a proposed acquisition of a 35 per cent interest in Loy Yang Power (an electricity generating plant in Victoria) by AGL would be likely to have the effect of substantially lessening competition in any relevant market.

11 In this decision French J observed that the electricity market is not static but one that is evolving over time:

> The geographic market is not to be determined by a view frozen in time or by observations based on shortrun time scales. The NEM [National Electricity Market] is an evolving market, which is intended and designed to operate as a single market for

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2 *Re: AGL Cooper Basin,* p 44,210.

> electricity throughout the regions that it covers. Transient price separations between those regions may define temporarily limited sub-markets which can be referred to for the purposes of competition analysis. And they may well attract the appellation 'market' in the ordinary parlance of suppliers and retailers operating within them. In my opinion, however, having regard to the structure of the market and the extent to which its major participants operate across regional boundaries, I am satisfied that there is only one NEM-wide geographic market for the supply of electricity, and associated with that, entry into electricity derivative contracts.[3]

12 Both the Tribunal and the Federal Court made it clear that the process of defining the market needs to take account of future conditions. In particular, the geographic bounds of the market need to be set with an eye to demand, supply and transportation conditions in both the present and in the medium to longer term. We will return to these issues later in section 5 where we draw some conclusions for market definition.

[3] *Australian Gas Light Company (CAN 052 167 405) v Australian Competition & Consumer Commission (No 3) [2003] FCA 1525.*

2. The PNG Gas Project

13 In this section we describe features of the PNG Gas Project (the Project), the customer base and record the difficulties the Project has encountered in securing foundation customers.

2.1. SNAPSHOT OF THE PNG PROJECT

14 The Project was established to extract natural gas from the Kutubu, Gobe, Moran and Hides fields in the Southern Highlands of PNG.[4] The gas from the fields would be transported via a 3,000km pipeline from PNG to Australia.[5] The project details were subsequently revised in 2003/04 to ensure that the existing facilities were fully utilised thereby reducing operating costs. The Kutubu/Moran oil fields will be converted to gas production; the Hides gas field will now be developed from the start of the project. The gas and liquids from Hides will be transported by pipe to Kutubu where they will be stripped. The liquids will be pumped into the existing oil export pipeline and gas will be pumped to Australia via a new wet gas pipeline. Any gas not required will be reinjected into the oil fields at Agogo and Katubu and possible Hides.[6] The pipeline route down through Australia has not been finalised[7], this will ultimately be determined by the location of the foundation customers.

15 The total cost of the development, including the construction of all necessary facilities to produce, treat and transport gas is estimated to be around US$3 billion.

2.2. HISTORY OF THE PNG GAS PROJECT

16 The original PNG export pipeline was initiated in 1996 to commercialise the gas resources of the PNG Highlands[8].

17 In June 2002 a Gas Agreement was signed between the State of PNG, the Bank of PNG and the Project sponsors, ExxonMobil, ChevronTexaco, Oil Search, MRDC (representing landowner interest) and Japan PNG Petroleum.[9] This Agreement outlined the parameters of the Project, and included the petroleum resources that would be dedicated, agreement for the PNG State to seek finance for 15 to 30 per cent equity in the infrastructure of the Project, the finalisation of the legal framework to develop the

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4 Papua New Guinea Department of Petroleum and Energy, *The PNG Gas Project – Project Brief*, October 2002 (pg 7)

5 http://www.exxonmobil.com.au/png/mn_png_pipeline.html

6 http://www.oilsearch.com.au/html/png_gas 17 November 2004

7 http://www.exxonmobil.com.au/png/mn_png_pipeline.html

8 http://www.oilsearch.com.au/html/png_gas 17 November 2004

9 Papua New Guinea Department of Petroleum and Energy, *The PNG Gas Project – Project Brief*, October 2002 (pg 7)

PNG gas resources, and the State's provision of stability in fiscal terms for either 20 years or up to the time when the base quantity of gas has been sold, whichever is earlier.[10]

18 The upstream section of the Project, which includes all facilities and pipelines in PNG will be designed and built by ExxonMobil and owned by all the project participants. The section from the PNG terminal facility, through the Torres Strait and down through Australia and including all the onshore Australian pipeline and facilities is called the downstream section.[11] The downstream portion of the pipeline from the Australia – PNG border was opened to international tender, and in May 1998 it was announced that the AGL Petronas consortium, APC, had been appointed to build, own and operate the PNG gas pipeline.[12]

19 In April 2003 Chevron Texaco announced that it intended to sell its interests in the PNG joint venture.[13] Oil Search subsequently acquired Chervon Texaco's interests.

20 In May, Esso Highlands Limited, a subsidiary of ExxonMobil Corporation was elected by the joint venture participants to be the operator of the Juha and P'nyang gas discoveries, this is in addition to being the operator of the PNG Gas Project.[14]

21 On 3 July 2003 ExxonMobil announced that the Heads of Agreement between the PNG Gas Project Owners expired on 30 June 2003. However, ExxonMobil, Oil Search, MRDC and Japan PNG Petroleum (now called Nippon Oil Exploration Limited) agreed to continue their efforts to commercialise their interests in the PNG gas resources from the Hides, Kutubu, Gobe, Moran, Angore and Juha fields under a new project and Heads of Agreement.[15] The new project was called the Highlands Gas Project.

22 On 6 October 2004 the ExxonMobil announced that the Project Owners had decided to move the Project to Front End Engineering and Design (FEED). This involves finalising the technical and design work on the upstream, PNG pipeline and export facilities, finalising government approvals and project finance and securing firm gas sales.[16] It is expected to take 12 – 18 months at which stage the Gas Project Owners will decide whether to proceed to the construction phase.[17]

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10 Papua New Guinea Department of Petroleum and Energy, *The PNG Gas Project – Project Brief*, October 2002 (pg 4) and ExxonMobil Media Release, *PNG Gas Agreement Signed*, 6 June 2002.

11 http://www.oilsearch.com.au/html/png_gas 17 November 2004

12 http://www.exxonmobil.com.au/png/mm_png_pipeline.html

13 ExxonMobil Media Release, *ExxonMobil Expands Operatorship in PNG*, 19 May 2003.

14 ExxonMobil Media Release, *ExxonMobil Expands Operatorship in PNG*, 19 May 2003.

15 ExxonMobil Media Release, *New Structure for PNG Gas*, 3 July 2003.

16 http://www.oilsearch.com.au/html/png_gas, 17 November 2004

17 ExxonMobil Media Release, *Confirmation of Additional Customers for PNG Gas Front End Engineering and Design (FEED) to Commence*, 6 October 2004.

23 In addition, a binding Letter of Intent was signed with APC (the AGL and Petronas consortium). This Letter of Intent will see APC undertake a FEED program for the gas pipeline from the PNG border to markets in Australia.[18]

24 In November 2004 it was announced that the Highland Gas Project would change its name to the PNG Gas Project

2.3. NEGOTIATIONS WITH CUSTOMERS

25 The Participants need the confidence that they will be able to recover the cost of their investment before commencing project construction. The Participants would be unwilling to commit the billions of dollars to fund project completion in the hope that enough customers eventually emerge. The ability of the Participants to negotiate firm contracts with foundation customers is therefore a vital prerequisite to this Project's viability.

26 Another reason for the reluctance of the Participants to build the infrastructure without locking in foundation customers is the substantially poorer bargaining position that the Participants would find themselves in negotiating sales once they had sunk their capital into the investment.

27 To provide this financial security and to support the viability of the Project the Participants have been actively seeking to sign up foundation customers.

28 Potential customers are located throughout Queensland, including Townsville, Rockhampton, Gladstone, Brisbane and Mt Isa. There have also been customers from New South Wales, Victoria, South Australia and the Northern Territory.[19] However as this section illustrates, the development of a firm customer base has been an extremely difficult process, and one characterised by a number of setbacks.

29 Over the course of the Project non-binding commitment from a number of potential customers have been negotiated, only to see many of these customers subsequently organise alternative sources of gas supply. The severe difficulties that have been experienced in building a robust list of foundation customers have been a significant problem for the Participants.

30 There are a number of factors that contribute to the difficulties in establishing agreements with customers. These difficulties are characteristic of large infrastructure projects where there are:

- long lead times for construction;
- large increments in demand required to support the economics of the Project; and
- large sunk costs.

[18] ExxonMobil Media Release, *Confirmation of Additional Customers for PNG Gas Front End Engineering and Design (FEED) to Commence*, 6 October 2004.

[19] ExxonMobil provided a list of customers that engaged in significant negotiations, Attachment 1.

31 A major problem is that potential customers are loath to commit to taking gas from the Project without some guarantee that it would go ahead. It is equally difficult for the Participants to provide such a guarantee without having first secured firm commitments from enough customers to ensure the Project is viable. This 'Catch-22' situation presents a significant hurdle to advancing projects of this type.

32 The potential customers that have entered negotiations with the Project and subsequently decided to discontinue the process include:

[Confidential information redacted]

33 Despite these setbacks the Project has successfully negotiated agreements with a number of customers.

- In July 2003 Energex announced a conditional agreement with the Project to take between 480 and 1,200 PJ over 20 years staring in 2007.[20] Energex will act as an aggregator for the purchase and on-sell to large commercial and industrial customers. The most significant customer is Comalco's alumina refinery at Gladstone.

- WMC Olympic Dam, a mining operation in South Australia, signed an indicative term sheet in December 2003 for the supply of between 12 - 20 PJ per annum for liquid fuel replacement and to fuel onsite generation.[21]

- In October 2004 agreement was reached with Queensland Alumina Limited (QAL) for the Project to supply 12 – 30 PJ of gas per annum for 20 years. The gas will be used at QAL's refinery in Gladstone.[22]

- Also in October 2004, the Project reached an agreement with CS Energy for the delivery of 10 PJ of gas per annum for 20 years to be used in electricity generation in Brisbane.[23]

34 In addition, a number of customers have indicated their interest in continuing negotiations with the Project once FEED is achieved.

[Confidential information redacted]

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20 ExxonMobil Media Release, *Sale of PNG Gas to Energex*, 8 July 2003.

21 ExxonMobil Media Release, *Sale of PNG Gas to WMC (Olympic Dam Corp)*, 12 December 2003.

22 ExxonMobil Media Release, *Confirmation of Additional Customers for PNG Gas Front End Engineering and Design (FEED) to Commence*, 6 October 2004

23 ExxonMobil Media Release, *Confirmation of Additional Customers for PNG Gas Front End Engineering and Design (FEED) to Commence*, 6 October 2004

3. Developments in the Australian gas sector

35 As anticipated in Section 1, the developments in the energy sector will be influential in guiding the inferences for market definition. This Section provides an overview of these developments, which highlight the considerable evolution of the Australian energy sector.

36 The Australian gas sector has been rapidly evolving in terms of the market opportunities and physical capacity. The major factors in this evolution include:

- new upstream supply options; and
- greater interconnection through the expansion of the network

These factors are discussed below.

As this section illustrates, the growth in gas demand comes from two sources – organic demand from existing users and new demand, principally from gas-fired generation and industrial load. The nature of large pipeline infrastructure projects, such as the PNG Project, is that they cannot rely on funding the project by harnessing organic growth alone and will only be successful if they can lock in a sufficient number of the new customers, which represent significant levels of additional gas demand.

However, as this section demonstrates, the demand side of the market remains relatively thin, and the Project is competing against a number of alternatives, including CSM. Moreover, although gas-fired generation occupies an important place in the National Electricity Market as a form of peaking generation, the further development of additional gas-fired generation capacity depends critically on policy decisions of governments with respect to greenhouse gas emissions. Uncertainty in respect of government policies on greenhouse has been cited as a significant deterrent to further investment in gas–fired generation.

Finally the investment in pipeline capacity, of which this Project forms a part, is also responsible for promoting greater competition across gas basins.

Taken together the market developments described in this section represent a significant challenge to the Project and serve to explain the genesis of many of the difficulties experienced by the Participants.

3.1. DEMAND FOR GAS

37 The demand for natural gas has been increasing rapidly over the past two decades, growing by an average of 4.3 per cent a year.[24] In part this is due to underlying growth in demand for gas for existing uses but also the emergence of a demand for gas for new uses. An example of a new application involves electricity generation, using gas to displace high greenhouse gas producing coal-fired generators.

38 Growth in the demand for gas has and will continue to provide the stimulus for the continued expansion and interconnection of gas production and the network. This results in more pipeline capacity between Basins and greater prospect for inter-basin competition.

3.1.1. Trends in consumption of gas

39 In 2001-02 Australia consumed 951 PJ of natural gas, which represented nearly 20 per cent of Australia's primary energy requirements.[25]

40 Of the 951 PJ of natural gas consumed in 2001/02:

- Western Australia was the largest gas user consuming 323 PJ (representing 34 per cent of total gas consumption);
- Victoria consumed 244 PJ (25 per cent of total primary gas consumption);
- NSW consumed 131 PJ (14 per cent of total primary gas consumption);
- SA consumed 142 PJ (15 per cent of total primary gas consumption);
- Queensland consumed 86 PJ (9 per cent of total primary gas consumption);
- Northern Territory consumed 26 PJ (3 per cent of total primary consumption); and
- Tasmania did not have access to natural gas.[26]

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24 ABARE, *Australian Energy, national and state projections, August 2004* (ABARE 2004), pg 23

25 ABARE 2004, Table 5, pg 23.

26 ABARE 2004, Table E2, pg 73-75.

	2004-05 PJ	2009-10 PJ	2014-15 PJ	2019-20 PJ
New South Wales	140	164	189	216
Victoria	264	308	358	409
Queensland	127	165	185	212
Western Australia	369	472	566	632
South Australia	139	166	185	207
Tasmania	10	18	20	21
Northern Territory	35	89	124	132
Total	**1,084**	**1,382**	**1,628**	**1,828**
Agriculture	0	0	0	0
Mining	121	193	260	285
Manufacturing and construction	383	503	577	633
Electricity generation	372	445	518	603
Transport	28	34	40	45
Commercial and services	46	52	59	67
Residential	134	154	174	195
Total	**1,084**	**1,382**	**1,628**	**1,828**

Table 1: Forecast gas consumption

Source: ABARE 2004, Table E2, pages 73-75 and Table G, pages 80-83.

41 The forecast increase in demand for natural gas by State to 2019/20 is shown in Table 1. Australian Bureau of Agriculture & Resources Economics (ABARE) has projected that demand for natural gas will increase by 3.7 per cent per year to 2019/20 (4.8 per cent per year between 2001/02 – 2008/09 – the medium term).[27] By 2019/20, natural gas consumption is forecast to double from the 2001/02 levels to 1,828 PJ per annum and will represent nearly 25 per cent of primary energy consumption.[28]

42 In comparison, the Australian Gas Association forecasts a higher percentage growth in demand for natural gas; 22 per cent of total energy supplied by 2005 and 28 per cent by 2014-15.[29]

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27 ABARE 2004, pg 23.

28 ABARE 2004, Table E1, pg 72.

29 ACCC, *Draft Greenfields Guideline for Natural Gas Transmission Pipelines*, 2002

43 ABARE estimate that the growth in demand for gas will be most significant in Western Australia and the Northern Territory, with the remaining States experiencing approximately 50 per cent increase in demand from 2004/05 to 2019/20.

44 Growth in the use of natural gas is projected to occur across most sectors, with almost 87 per cent of the growth forecast to occur in the following sectors:

- mining (21 per cent);
- manufacturing (33 per cent); and
- electricity generation (33 per cent).[30]

3.1.2. Electricity sector demand for gas

45 The quantity of electricity generated from natural gas in Australia is increasing. In 2001/02, 313 PJ of natural gas was used to produce electricity.[31] This is forecast to increase to:

- 372 PJ in 2004/05 (out of 2,457 PJ total fuel for electricity generation, approximately 15 per cent);
- 445 PJ in 2009/10 (out of 2,754 PJ total fuel, approximately 16 per cent);
- 518 PJ in 2014/15 (out of 3,004 PJ total fuel, approximately 17 per cent); and
- 603 PJ in 2019/20 (out of 3,311 PJ total fuel, approximately 18 per cent).[32]

46 This represents an increase in output from gas-fired generation of 5 per cent per annum to 2019/20, and will be particularly strong in the medium term growing by 6 per cent per annum from 2001/02 to 2008/09.[33]

47 In 2001/02, electricity generators using gas produced 30.5 TWh of electricity, nearly 14 per cent of all electricity produced in Australia. Gas-fired generation output is forecast to grow to:

- 46.5 TWh in 2008/09; and
- 69.3 TWh in 2019/20[34]

48 Table 2 provides current and forecast gas-fired generation output across all States and the Northern Territory.

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30 ABARE 2004, Table E1, pg 24.

31 ABARE 2004, pg 85.

32 ABARE 2004, Table G, pg 81. The forecast provided by ABARE incorporates the effects of the proposed greenhouse schemes.

33 ABARE 2004, pg 26.

34 ABARE 2004, Table 9, pg 27.

Jurisdiction	2001/02	2008/09	2019/20
New South Wales	2.1	3.1	5.7
Victoria	2.1	3.6	6.8
Queensland	3.1	9.4	12.4
Western Australia	13.6	17.9	27.2
South Australia	7.5	9.2	12.4
Tasmania	0	0.6	0.9
Northern Territory	2.1	2.8	3.8
Total	**30.5**	**46.5**	**69.3**

Table 2: Gas-fired electricity generation (TWh per annum)

Source: ABARE 2004, Table 9, page 27.

49 ABARE forecasts that Queensland gas-fired electricity generation output will grow by 17 per cent from 2001/02 to 2008/09, reflecting the impact of the State's 13 per cent scheme (see section 3.1.4 for a description of the scheme).[35]

50 Queensland is projected to account for around 24 per cent of growth in gas-fired electricity generation in Australia between 2001/02 to 2019/20 (nearly 40 per cent between 2001/02 to 2008/09).[36]

51 The ABARE forecast also considers the effects of the New South Wales greenhouse Benchmark Scheme, and acknowledge it is difficult to fully anticipate the exact impact of the scheme. However, ABARE estimate that gas-fired electricity generation will grow at 6 per cent per annum from 2001/02 to 2019/20 in New South Wales.[37]

52 The increase in Victorian gas-fired electricity generation is estimated to be 8 per cent per annum from 2001/02 to 2008/09.[38]

53 Growth in the output from gas-fired generation occurs across all States over the study period, with Tasmanian gas-fired generation commencing operations in 2004/05.[39]

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35 ABARE 2004, Table 9, pg 27.

36 ABARE 2004, Table 9, pg 27

37 ABARE 2004, Table 9, pg 27

38 ABARE 2004, Table 9, pg 27

39 ABARE 2004, Table 9, pg 27

3.1.3. Gas–fired electricity capacity

54 The increase in gas use is expected to be associated with greater utilisation of existing plant but also through the development of new plant. Below we briefly describe recent additions and expected additions to the stock of gas-fired power plants[40]:

- Victoria
  - Somerton 160MW gas fired commissioned 2002;
  - Bairnsdale 80 MW gas fired commissioned 2001;
  - a number of small landfill gas projects have been developed including Berwick, Broadmeadows, Clayton and Springvale approximately 35MW; and
  - Maryvale and Laverton 200 and 200-400MW respectively. These proposed plant will operate on gas.
- NSW
  - Appin and Tower plants operate on coal mine waste methane (CMM)[41] and combined represent 95 MW;
  - Teralba is a an 8 MW generator fuelled by CSM gas;
  - there are also a number of small embedded generators operating on landfill gas approximately 30MW.
- Queensland
  - Roma 75MW plant is a gas fired generator commissioned in 1999;
  - Bulwer Island 32 MW is a CCGT plant commissioned in 2000;
  - Swanbank D a 37 MW gas-fired generator commissioned in 1999;
  - Swanbank E is a 380MW generator operating on gas and commissioned 2002;
  - Mica Creek is 325MW gas-fired generator – not connected to the grid commissioned between 1997 and 2001;
  - Townsville expansion will be 200MW generator operating on CSM due for completion in 2005;

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40 NEMMCO and ESAA, *Electricity Australia 2003*, 2003

41 CMM involves the utilising the methane that is extracted from operational mines which would otherwise been vented as opposed to CSM which involves drilling specifically for methane.

- in addition, a number of small landfill gas generators have developed Roghan Road, Rochedale and Whitwood, which represent about 10MW.

- South Australia
  - Hallett is a 220 MW plant operating on gas and commissioned in 2002;
  - Quarantine is a 100 MW plant operating on gas and commissioned in 2002;
  - Ladbroke Grove another 80 MW gas fired plant was commissioned in 2000.

55 ABARE's energy projections imply the addition of 4,660 MW of gas-fired generation post 2003 is required, with most of the investment forecast to occur in Queensland.[42] It is estimated that an additional 1,135 MW of gas-fired generation will be required in Queensland to meet the increased output by 2019/20, a consequence of the Government's 13 per cent scheme.[43]

56 In the future, it is possible that the Australian electricity generation sector will be subject to stricter greenhouse constraints. Indeed, in its recently-released Draft Review of National Competition Policy Reforms, the Productivity Commission identified externality pricing as an important element in the future infrastructure reform agenda. It cited a recent EU study that estimated that if externalities were fully accounted for, the cost of coal-generated electricity would double, while that of gas-generated electricity would increase by only 30 per cent.[44]

57 Although the Commonwealth Government has stated that it will not ratify the Kyoto Protocol, the State and Territory Governments have formed a Working Group to consider implementing a national emissions trading scheme. Such a scheme is likely to further promote the development of gas-fired generation, which will in turn increase the demand for gas across Eastern Australia and the demand for greater gas network interconnection.

58 The net effect of these three policies is likely to be a significant increase in the supply of gas-fired generation, using both conventional natural gas and CSM.

59 However, although there is a move towards stricter greenhouse regulation, uncertainty in the policy process continues to undermine the incentives to invest in additional gas-fired generation. The problems confronting the industry in responding to an uncertain greenhouse policy environment has been recently highlighted by Origin Energy:

> In Australia, there is no uniform mechanism for valuing carbon which means there is no clear signal for building in the cost of carbon into new energy infrastructure.

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42 ABARE 2004, pg 29.

43 ABARE 2004, pg 29.

44 Productivity Commission, *Review of National Competition Policy Reforms*, Discussion Draft, 2004, ch 8 and pg112.

> We believe that a comprehensive greenhouse and energy policy framework is required now, as investments in the energy industry are long-term, and require substantial financial input. [45]

3.1.4. Greenhouse regulation

60 As intimated above, the change in the regulatory environment of the gas industry and the adoption of greenhouse schemes, has had, and is expected to have a significant effect on the demand for gas.

61 New gas developments are being encouraged by three existing greenhouse policies:

- the Queensland 13 per cent Gas Scheme;
- the NSW Greenhouse Benchmark Scheme; and
- the Commonwealth Greenhouse Gas Abatement Project (GGAP) Scheme.

The Queensland 13 per cent gas scheme

62 In May 2000 the Queensland government announced the *Queensland Energy Policy – A Cleaner Energy Strategy*. The objectives of this policy are to:

- diversify the State's energy mix towards the greater use of gas and renewables;
- facilitate the supply of abundant and competitively priced gas in Queensland;
- facilitate the development of gas fired power stations, particularly a base load power station in Townsville; and
- reduce the growth in greenhouse gases.[46]

63 The scheme requires electricity retailers to purchase at least 13 per cent of the electricity sold in Queensland from gas-fired generation. The scheme is one component of a broader energy policy and will commence on 1 January 2005 and remain in place until 31 December 2019.

64 The strategy aims to increase the proportion of gas-fired generation in the State's electricity supply.

65 Eligible gas-fired generators will be entitled to create one Gas Electricity Certificate (GEC) for every megawatt hour produced. Retailers and other liable parties are required to purchase and surrender Gas Electricity Certificates (GECs) to meet the scheme requirements. Only generators in Queensland may create GECs.

66 A wide variety of gas sources can contribute to the scheme; including Queensland's conventional natural gas fields and the large potential resources of CMM and CSM.

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45 www.originenergy.com.ay/sustainability2003/environment.html

46 Queensland Treasury, Consultation Paper: *The Queensland 13 per cent Gas Scheme*, September 2001.

NSW Greenhouse Benchmark Scheme by 2007

67 This scheme aims to reduce emissions associated with electricity production by 5 per cent per capita compared with 1990 levels.

68 The NSW Greenhouse Benchmark Scheme is aimed primarily at retailers. Retailers (and a small number of other liable parties) are obliged to meet their own individual benchmarks in every year. This is based on the amount of electricity they sell to customers and the number of abatement certificates that they purchase to offset emissions attributed to them.

69 The NSW Greenhouse Benchmark Scheme also rewards gas-fired generation. Any new gas-fired power plant in the National Electricity Market (NEM) is entitled to create certificates (NSW Greenhouse Abatement Certificates, or NGACs) under the scheme.[47] Extra encouragement is given to CMM projects, reflecting the greenhouse benefits of avoiding fugitive methane emissions that would otherwise occur as part of mining operations This extra encouragement means that a CMM electricity generation project would be more likely to create NGACs than GECs.

70 Frontier Economics previously undertook a modelling exercise for the Market Implementation Group within New South Wales Treasury, as part of the requirement to develop the scheme. The modelling of the Greenhouse Benchmark Scheme examined the likely affects on output from different generating technologies. The results of the analysis suggest that the NSW Greenhouse Benchmark Scheme will provide an incentive for more gas capacity and gas generation at the expense of coal fired plant compared with an assumed 'business as usual' base case (see Figure 1 and Figure 2).[48] It is expected that an additional 1,000 to 4,000 GWh of gas generation per annum will be required to meet the greenhouse target (depending on the year). Coal gas (CMM and CSM) experiences a significant increase in output and capacity also.

71 Whilst the ABARE study and the Frontier Economics assessment of the NSW Greenhouse Benchmark Scheme are not directly comparable, both anticipate a significant increase in the utilisation of gas in the production of electricity

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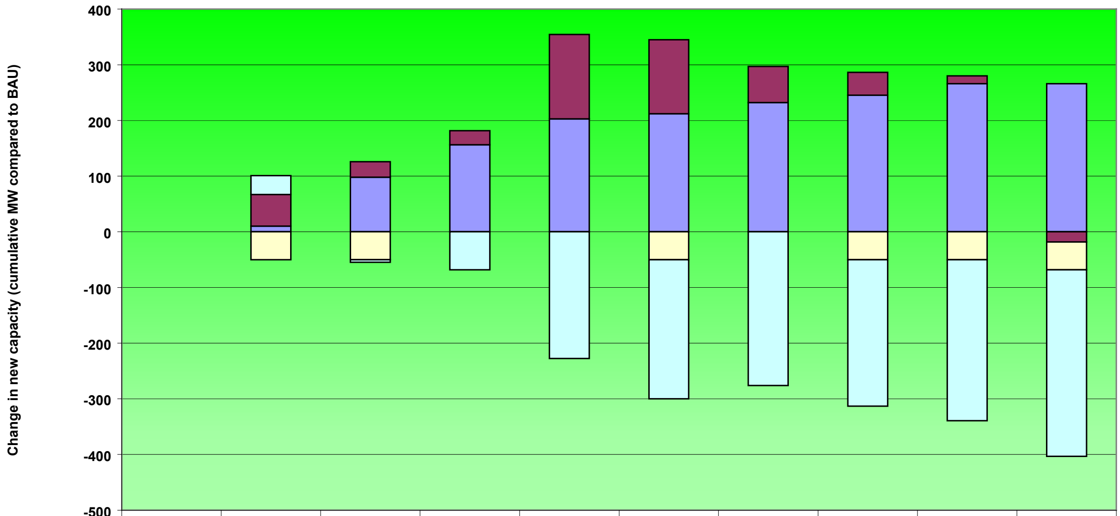
[47] A new gas fired generator would be able to create certificates according to the difference between the emissions intensity of its output compared with the NSW pool coefficient. Roughly speaking, if the pool coefficient were set at 0.9 t/MWh (for 2004, it was 0.906t/MWh), and the emissions intensity of the new gas plant was 0.4 t/MWh, then the plant would be entitled to create 0.5 certificates for every megawatt hour produced. At an approximate NGAC price of $10, this equates to a $5/MWh production subsidy.

[48] Note that this modelling was performed some time ago and should only be viewed as an indication of possible impacts, rather than a forecast of outcomes under the scheme.

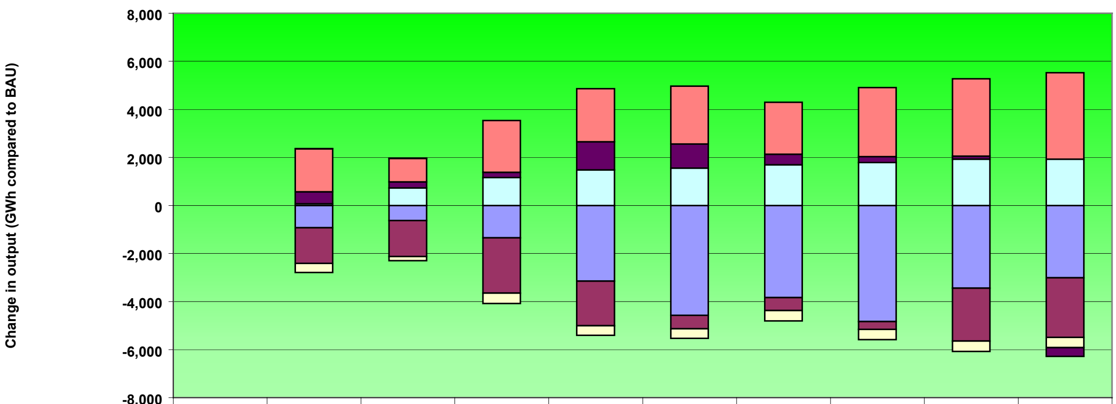


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Renewable	0	34	-5	-68	-228	-250	-276	-263	-289	-335
New gas		-50	-50			-50		-50	-50	-50
DSM		57	28	25	152	133	65	41	14	-18
Coal gas		10	98	156	203	212	232	245	266	266

Financial Year (ending 30 June)

Figure 1: Modelled changes in capacity caused by NSW benchmarks scheme

Source: Frontier Economics



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Renewable	0	0	0	0	0	0	0	0	0	0
New black coal - Q		6	3	1						
GT		2								
Gas		1,786	987	2,154	2,208	2,409	2,163	2,880	3,222	3,597
DSM		499	245	219	1,164	1,010	443	244	122	-366
Coal gas		70	731	1,159	1,485	1,548	1,689	1,783	1,928	1,928
Brown coal		-376	-172	-435	-401	-404	-434	-431	-432	-430
Black coal - Q		-1,487	-1,500	-2,302	-1,856	-559	-535	-325	-2,206	-2,483
Black coal - N	0	-925	-624	-1,347	-3,148	-4,573	-3,834	-4,834	-3,436	-3,006

Financial Year (ending 30 June)

Figure 2: Modelled changes in output caused by NSW benchmarks scheme

Source: Frontier Economics

Commonwealth GGAP program

72 The Commonwealth's GGAP program is designed to encourage large-scale greenhouse abatement projects. The Government has already allocated substantial sums through this program to develop CMM and CSM resources. The projects include:

- the German Creek colliery in Central Queensland which produces electricity from CMM;
- CMM electricity generation projects in NSW and Queensland conducted by Envirogen;
- Centennial Coal in NSW producing electricity from CMM;
- BHP Billiton West Cliff colliery - producing electricity from CMM;
- Envirogen, NSW South Coast (Bellambi mine) producing electricity from CSM;
- La Trobe Valley to develop technology to pre-dry brown coal before use in power stations; and
- the Comalco Alumina Refinery has been funded to replace fuel oil boilers and kilns to natural gas.

73 The GGAP program has also provided considerable funding for cogeneration projects, which will also increase the demand for gas throughout Australia. The fund has also been instrumentally in increasing the supply and demand of CMM.

3.1.5. Depth of demand

74 The growth in gas demand, as outline above, provides a foundation for investment in additional gas supply, including pipeline infrastructure. However, notwithstanding this growth in gas demand the market remains relatively 'thin' and remains characterised by a relatively small number of large end users.

75 The requirements of the large users, such as large industrial loads and gas-fired generators, are generally for relatively long-term contracts. Although these users represent potentially very attractive customers to the Participants, there is also a problem if these customers subsequently obtain their gas requirement from another supplier since they typically enter into long-term a agreement - which generally denies the Participants an opportunity to contract with these customers. The lack of depth in the market means that the loss of even a small number of potential customers places a significant obstacle in front of the Participants. Thus, while the market is characterised by low levels of liquidity, joint marketing will be the preferred approach. However, if liquidity substantially improved, the arguments for retention of joint marketing would be weakened.

76 Unfortunately a substantial improvement in liquidity is not expected to occur soon. For example, although demand for gas is anticipated to increase by 3.7 per cent per annum up to 2019/20[49] Australia only has a small number of end users that account for a significant amount of total gas consumption. In ABARE's biannual survey which examines energy consumption by fuel it was reported:

- Five firms in Australia account for nearly 25 per cent of all gas consumption; and
- between thirty – forty firms for 50 per cent of total gas consumption.

If we consider only the Eastern States, including South Australia:

- seven firms account for 25 per cent of gas consumption; and
- thrity-four firms for 40 per cent of consumption.[50]

77 A concern over a lack of liquidity in the gas market was a key driver in a review announced by the Victorian Minister for Energy and Resources of the arrangements for the pricing and management of Victoria's wholesale gas market.[51] This review recently presented its recommendations to the Minister. These recommendations included modifications to the spot market to *ex-ante* pricing, and the introduction of transmission rights.

78 The amendments to the spot trading arrangements were considered by VENCorp to improve the performance of the market arrangements and to reduce the trading risk for those participants who choose to trade in the spot market. In principle these risks arise, in part, from an illiquid market, which could hinder the ability of participants to respond to changing market conditions within the day.

79 The lack of liquidity in demand is unlikely to alter significantly in the future. ABARE suggest (based on anecdotal evidence) many customers prefer to negotiate a contract through a gas retailer.[52]

80 ABARE suggest that the reliance by large end users of gas on gas retailers to negotiate contracts has led to the dominance of five major gas retailers in Australia:

- AGL;
- TXU;
- Origin Energy;
- Alinta; and

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49 ABARE 2004, pg 23.

50 ABARE, Australian Gas Markets moving toward maturity (ABARE 2003), December 2003, pg 35.

51 Minister for Energy Industries and Resources Media Release, Gas Review to Boost Victorian Market, 10 April 2003.

52 ABARE 2003, pg 10

- Energex.[53]

81 ABARE's estimated increase in consumption to 2019/20 is unlikely to significantly alter the fundamental characteristics of the demand side of the gas market. Of the increase in consumption in the manufacturing sector, 75 per cent of this is accounted for by 4 projects.[54]

82 The foundations for greater competition between suppliers is enhanced by moves to market instruments such as:

- The development of the Victorian gas spot market in 1999. Whilst the majority of gas is traded under commercially negotiated contracts the market provides a mechanism for participants to trade their imbalances through a competitive bidding process;[55]

- the development of underground storage. In Victoria, the Underground Gas Storage (UGS) uses depleted gas reservoirs to store natural gas. The gas is generally injected during Summer when there is less demand and withdrawn during high Winter demand[56]. The UGS provides the potential for greater competition during the high demand periods; and

- VicHub publishes spot prices for gas at Sydney, Longford, and Tasmania. The objective of the Hub is to assist market participants hedge their risk in the wholesale gas market and improve the interconnection of gas between New South Wales, Victoria ands South Australia.[57] The opportunity to purchase gas from different sources such as the VicHub creates an environment where producers and sellers are encouraged to compete to supply the demand.

83 The limited amount of underground storage and lack of liquidity in the spot market has reduced their short-term effectiveness. However, The Energy Users Association of Australia and the Energy Action Group indicated that while the developments in the Victorian gas market had been small scale they have provided the *potential* for producer competition.[58]

84 Competition has also been encouraged between suppliers from different States by the adoption of swap contracts. In May 2004 Santos Limited and the South West Queensland Gas Producers (SWQGP) entered a Heads Of Agreement with Origin Energy Retail for the swapping of up to 200 PJ per annum of gas between Queensland and the Moomba Gas Hub, with an option to increase the volumes. Origin will deliver gas produced in its central Queensland fields to the SWQGP at Roma in Queensland. The SWQGP will then use this gas to meet part of their customer requirements in south-

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53 ABARE 2003, pg 10

54 ABARE 2003, pg 36.

55 Vencorp, *Vencorp's Guide to the Gas* Market, 2001.

56 http://www.dpc.vic.gov.au/doimno/web_notes/pressrel.nsf/4a256ce0017cf654a2562 27 October 2004

57 Energetics, *Victorian Gas market Update*, May 2003.

58 The Energy Users Association of Australia and the Energy Action Group, *Submission to Review of Provisions of the Gas Industry Act Relating to Significant Producers*, May 2003 pg 4.

east Queensland. In return for the gas from Origin, the SWQGP will redirect (swap) an equal quantity of Cooper Basin produced gas to Origin at the Moomba Gas Hub.

85 The swap will continue until December 2011. The access to swapped gas reduces transport costs and processing costs, increasing competitive pressures to provide low cost gas supplies.[59]

86 The swap arrangements are based on Origin being able to provide the required volumes from their CSM reserves in the Bowen Basin. The substantial size of this deal between significant gas market participants also signals that the market accepts that these gas reserves are reliable and deliverable as required by customers, enabling CSM to overcome this stigma. This will assist in enabling the CSM reserves to compete more freely with conventional gas supplies, again increasing the competitive pressure in the market.

3.2. GAS SUPPLY

87 Gas supply and basin diversity has increased significantly over the past few years. JP Morgan report that new basins have signed up volumes equivalent to between 30 and 50 per cent of current eastern Australian gas demand.[60] This section provides an overview of these supply-side developments. One significant development has been the emergence of CSM as a significant source of gas for eastern Australia.

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59 Santos media release, *Cooper Basin and Origin in major gas swap agreement*, 6 May 2004.

60 JP Morgan, Utilities Markets – Gas Markets Reviewed, Electricity Customer Churn Plateaus, 15 October 2004.

3.2.1. Natural gas

88 In 2001 the majority of Eastern Australian States were supplied with natural gas from the Gippsland and Cooper/Eromanga basins, shown in Table 3.

Jurisdiction	Basin	Location	% of demand supplied by basin
New South Wales	Cooper	SA	85
	Gippsland	Vic	15
Queensland	Surat/Bowen	SA/Qld	40
	Cooper/Eromanga	Qld	40
	Coal seam methane	Qld	20
Victoria	Gippsland	Vic	90
	Otway	SA	7
South Australia	Cooper	SA	100
Western Australia	Carnarvon	WA	97
	Perth	WA	3
Northern Territory	Amadeus	NT	100

Table 3: Source of State natural gas supplies in 2001

Source: ABARE (2002), Australian gas supply and demand balance to 2019-20

89 In Table 4 we present the natural gas reserves. In 2001, it was estimated that Australia had 158,534PJ of reserves.[61] The Cooper/Eromanga basin represents 30 per cent of the south eastern Australian reserves, with the Gippsland providing 54 per cent.

90 Of the total reserves in eastern Australia 66 per cent were rated as 'commercial' in 2001. This provides an indication of the basins that are likely to be developed based on their volumes of reserves.

91 The supply cost information also contained in Table 4 indicates the cost of gas supply to the Victorian market is lower than that for South Australia, New South Wales and Queensland. Only consumers in the Western Australian market experience a lower cost of supply than Victoria.

[61] Geoscience Australia, *Oil and Gas Resources of Australia 2002.*

Basins	Reserves: Commercial (PJ)	Reserves: Non- commercial (PJ)	Total Reserves (PJ)	Production (PJ)	Supply Cost (PJ)
Eastern Australia					
Adavale	14	-	14	1	2.50
Bass	-	376	376	-	na
Bowen-Surat	107	122	229	24	3.00
Cooper-Eromanga	3,503	913	4,416	211	2.86
Gippsland	5,974	2,055	8,029	239	2.60
Otway	30	1,670	1,700	8	2.60
Subtotal	9,628	5,136	14,764	483	
Northern and Central Australia					
Amadeus	335	23	358	19	2.50
Bonaparte	10	27,067	27,077	-	na
Browse	-	33,671	33,671	-	na
Subtotal	345	60,761	61,106	19	
Western Australia					
Carnarvon	23,538	58,141	81,679	720	1.90
Perth	103	882	985	11	2.70
Subtotal	23,641	59,023	82,664	731	
Total	**33,614**	**124,920**	**158,534**	**1,233**	

Table 4: Australian natural gas reserves, production and estimated supply costs

Source: Geoscience Australia (2002), Department of Industry Tourism and Resources (2000) and Woollands, Wong and Bernecker (2002), as cited in Dickson and Noble 2003, pg 135-145.

3.2.2. Gas field developments – post 2001

92 Since the ABARE study in 2001 a number of announcements have been made which will see some of the reserves outlined in Table 4 developed.

93 The recent exploration activity in the Bass, Otway and Gippsland regions is proving that a number of reserves can be commercially developed. In particular the development of the Casino field by Santos and JV partners has lead to a contract to supply up to 493 PJ over 12 years. The recent announcement by Woodside and JV partners for the development of the Geographe and Thylacine gas fields in the Otway Basin. This project will initially deliver 60 PJ per annum, which is equivalent to 10 per cent of south-eastern Australia's current annual gas demand.[62]

94 The Minerva Project, also in the Otway Basin, operated by BHP Billiton is due to start operation later this year. The field will yield 317 PJ over 10 years[63].

95 In Bass Strait the AWE/Origin Energy development of the Yolla gas field is also nearing completion. The project will yield 256 PJ, which is equivalent to 10 per cent of Victorian gas demand for 15 years.[64]

96 The development of these fields will assist in being able to meet the forecast demand growth described in section 3.1.1.

3.2.3. Coal Seam Methane

97 CSM has become a significant source of gas for eastern Australia. Some of the major advantages enjoyed by CSM over other forms of energy include the proximity of CSM reserves to users, shorter lead times on project developments, and the ability for CSM developments to utilise the substantial network of existing gas pipelines.

98 As this section demonstrates, CSM supplies a quarter of Queensland's gas demand, and is projected to become an important source of energy in New South Wales.

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62 Department of Primary Industries, Victoria's Earth Resources Journal, Discovery, "Otway Gas takes off", September 2004 pg 8.

63 BHP Billiton, *Minerva Gas Field Development.*

64 Origin Energy, *BassGas Project Overview.*

New South Wales

99 New South Wales has sizeable coal basins with extensive resources of CSM. It is estimated that the volumes of CSM in NSW is several times greater than the current reserves for conventional natural gas.[65] Excluding urban areas, colliery holdings and National Parks, the potential CSM resources listed in Table 5 have been estimated.

Basin	Total (billion m3)	Potentially recoverable -20% recovery factor rate (billion m3)
Sydney	752	146
Gunnedah	732	150
Clarence-Moreton	1,075	215

Table 5: Potential New South Wales CSM reserves[66]

100 Demand for this gas is located close to the sources of CSM whereas conventional natural gas resources are generally located at significant distances from the demand. This means that successful development of CSM could avoid significant transport costs. This represents a significant competitive advantage for CSM projects over projects such as the PNG pipeline. As extraction technology improves CSM is likely to become a substantial source of competition with natural gas.

101 In New South Wales:

- Tower and Appin mines extract CMM to generate electricity. Country Energy also has an embedded generator that operates on CSM – Teralba 8MW.
- the Sydney Gas Company (Sydney Basin) and Eastern Star Gas (Gunnedah Basin) are progressing with programs to reticulate the CSM gas from these two basins. In response to the development of the CSM supply, Sydney Gas Company recently entered into contracts with AGL to provide 15PJ per annum of CSM gas over 10 years, and is expected to produce 35 PJ per annum in a few years time.[67]

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65 http://www.minerals.nsw.gov.au/geosurvey/petrol/csm.htm

66 Mineral Resources of NSW, Coal Seam Methane Potential of NSW

67 http://www.agl.com.au/agl/press+releases

Queensland

102 In 2002, 25 per cent of Queensland's gas demand was met by CSM production.[68]

103 The agreements or projects that have either been negotiated or commenced in Queensland include:

- in June 2002 the Queensland Government announced that gas supplied from the Moranbah Gas Project through the Moranbah-Townsville pipeline under a gas sales agreement with Enertrade, would be used to repower Yabula power station near Townsville in early 2005. The company CH4 would supply the CSM gas from a field near Moranbah;[69]
- CH4 is continuing exploration with the intention of doubling CSM gas reserves to 1,000P;[70]
- in December 2002 Origin and Oil Company of Australia (OCA) announced a long-term agreement to supply 340 PJ of CSM from the Surat and Bowen Basins to service AGL's customers in South Australia, New South Wales, and ACT. The contract lasts for 15 years and commences in 2005. The agreement also includes the delivery of gas to Moomba through arrangements with owners of exiting pipelines and through a proposed new pipeline from Ballera to Moomba. This development means that CSM gas has demonstrated the ability to compete with the large gas producers in Victoria and South Australia;[71]
- increasingly, project developers are considering the option of using CSM gas to fuel their generation operations. For example, contracts between CS Energy, Santos and QGC were negotiated for the supply of 120 PJ of CSM gas over 15 years to power Swanbank E;[72]
- Energex and Moura Sales have entered a long-term contract for the supply of CSM gas from the Moura mine in central Queensland. Over the 10 year contract 4 PJ per annum of CSM gas will be on sold to Comalco in Gladstone.[73]

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68 Queensland Government Natural Resources, Mines and Energy, *Facts Coal Seam Methane in Queensland*, August 2004.

69 Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

70 Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

71 Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

72 Power Industry News, PNG Gas deal with CS Energy, 7 October 2002 edition 314.

73 Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

104 In addition to these developments there are a number of other CSM projects being actively pursued:

- the OCA has been active in Queensland developing the Peat and Dawson Valley basins for CSM production. OCA also has other smaller interests in other Queensland fields, including Durham, Walloon and NE Bowen;[74]
- Tipperary Oil is developing the CSM project at Comet Ridge;[75]
- in 2003 Molopo announced the development of a CSM extraction program for Mungi;[76]
- the Queensland Gas Company (QGC) is examining areas in the Surat Basin for future CSM development;[77]
- Arrow Energy is undertaking exploratory drilling in the Surat and Clarence-Moreton basins with encouraging results.[78]

Summary

105 CSM has become a major source of additional gas supply, particularly in Queensland, and with considerable potential for CSM development in NSW. As the extraction technology improves CSM will be able to further exploit its natural advantage of being able to locate fields close to the sources of demand thereby avoiding, to a large degree, the significant sunk costs associated with building gas pipelines. These advantages, combined with the extensive nature of CSM reserves, have been instrumental in the recent development of CSM reserves.

106 This positive outlook for CSM is shared by the CoAG Energy Market Review Committee:

> Concerns regarding security of supply of gas or adequacy of reserves into the future appear to be unfounded. In addition to these vast conventional gas reserves, ongoing research and development into extraction techniques continues to lower the cost of coal seam methane, making it a more viable option.[79]

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[74] Oil Company of Australia, Presentation to the Townsville Enterprise Energy Forum, *Coal Seam Gas – A reliable energy source for Queensland*, 23 May 2002.

[75] Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

[76] Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

[77] Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

[78] Bureau of Mining *Petroleum, Queensland Minerals and Petroleum Review of 2003*. 2003

[79] Council of Australian Governments Energy Market Review, Towards a Truly Competitive Efficient Energy Market, December 2002 pg 185.

3.2.4. Supply-demand balance to 2019-20

107 In 2003 Dickson and Noble of ABARE analysed how eastern Australian gas demand could be supplied into the future. The analysis assumed:

- production from the Cooper-Eromanga field would fall from 235 PJ per annum in 2001/02 to 190 PJ by 2019/20;
- Gippsland gas production would be capped at 360 PJ per annum;
- production from the Otway and Bass Basins were capped at 125 and 20 PJ per annum respectively; and
- CSM supplies would increase from 34 PJ per annum in 2000/01 to 100 PJ per annum in 2019-20.

108 Under these assumptions, eastern Australian gas demand could be met by existing sources to 2011/12. However, additional northern supply (either PNG or Timor) of about 20 PJ per annum would be required from 2012/13 onwards. Table 6 describes this scenario and assumes 100 PJ per annum of northern supply is available from 2012/13, which reduces production from existing fields in the following years compared to what would otherwise occur.

109 Dickson and Noble also consider several sensitivities that progressively increase eastern Australian supplies.

- Sensitivity 1: Cooper Eromanga production remains constant at 235 PJ per annum. This allows for eastern Australian demand to be met until 2012/13.
- Sensitivity 2: the Gippsland basin produces additional supplies up to 400 PJ per annum) demand would therefore be met until 2014/15.

110 Using the sensitivity assumptions, Eastern Australian demand beyond 2014/15 would be met by increased production from the Gippsland Basin combined with pipeline expansion or augmentation and commercial reserves would be depleted by 2016/17.[80]

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[80] Dickson and Noble (2003), pg 144

Year	2004-05 PJ	2010-11 PJ	2011-12 PJ	2012-13 PJ	2013-14 PJ	2014-15 PJ	2019-20 PJ
Production							
Bass	20	20	20	20	20	20	20
Bowen-Surat	13	10	10	0	0	0	0
Cooper-Eromanga	228	213	210	208	205	203	190
Gippsland	265	336	358	337	345	348	360
Otway	63	125	125	77	90	77	125
Subtotal	588	704	723	642	660	648	695
Coal seam methane	60	82	83	85	86	90	100
Ethane	36	36	36	36	36	36	36
Total eastern Australian production	685	822	842	763	782	774	831
Northern supply option	0	0	0	100	100	129	177
Total	685	822	842	863	882	903	1008
Consumption							
New South Wales	173	200	203	205	208	211	230
Victoria	273	317	325	334	341	349	388
Queensland	115	137	141	145	148	152	177
South Australia	117	152	158	164	169	174	193
Tasmania	7	16	16	16	16	17	20
Total	685	822	842	863	882	903	1008

Table 6: Estimated eastern Australian demand-supply balance

Source: Dickson and Noble (2003)

Supply since the study period

111 It should be noted that in their analysis Dickson and Noble stress the conservatism inherent in their modelling assumptions:

> "it is almost certain that the current estimate of commercial reserves represent a lower bound and there will be future additions to Australia's identified resource base."[81]

[81] Dickson and Noble (2003), pg 144.

112 Dickson and Noble also stated that the constraint to balancing eastern Australian gas demand and supplies over the longer term was not the availability of commercial reserves but rather the deliverability from Eastern gas basins. Consequently, Dickson and Noble suggested that the market would rely on new sources of supply in the future, if not within the next decade[82]

113 Since the Dickson and Noble study a number of gas supply options have progressed in the eastern Australian market, including the Bass, Otway and Gippsland fields.

114 As outline above CSM could also act as significant supply source and competitor with conventional gas. With a number of companies investigating and drilling, the development of the CSM fields are likely to emerge quickly in the event of a gas shortfall.

115 These new projects, in addition to a greater utilisation of CSM, will mean that gas reserves are likely to extend beyond 2020.

3.2.5. Ownership of gas reserves

116 The exploration and production of natural gas in Australia is usually undertaken by companies forming a joint venture. The key companies involved in these joint ventures include:

- BHP Billiton;
- BP;
- Chevron Texaco;
- ExxonMobil;
- OMV;
- Origin Energy;
- Santos; and
- Shell and Woodside Energy.

82 Dickson and Noble (2003), pg 144

117 In 2001 three firms accounted for the majority of gas reserves. However, ABARE suggest that there are a number of emerging gas suppliers that will help reduce but not eliminate their dominance by 2010. ABARE identify five new firms operating in the following basins:

- Minerva;
- Particia/Baleen;
- Yolla;
- Thylacine/Geographe; and
- Coal seam methane.[83]

118 Overseas experience suggests that there maybe economies of scope in the discovery/production process where gas sources are significant distances from the demand. This combined with the small size of the eastern gas market is likely to result in a limited number of market suppliers over the long to medium term, despite the increase in the number of participants.[84]

119 Although the number of participants in the gas market may not expand substantially, a key issue will be the scope for greater competition between suppliers, or what is generally known as 'inter-basin' competition. The following section provides an overview of interconnection developments that have enhanced inter-basin competition.

3.3. INTERCONNECTION

120 The development of access arrangements for the third party use of pipelines, as well as the extension of the pipeline transmission system throughout Australia has increased the opportunity for competition in the supply of gas. In this section we describe these changes and examine how this has transformed the competitiveness between suppliers in the gas sector.

3.3.1. Access arrangements

121 On 7 November 1997 all jurisdictions signed the CoAG Natural Gas Pipelines Access Agreement (the Agreement). The Agreement sets out the States' obligations to give legislative effect to the Gas Access Code within a specific timeframe and to take other actions to implement and maintain the integrity of the Code.

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83 ABARE 2003, pg 33

84 ABARE 2003, pg 34.

122 The Gas Access Code sets out the rights and obligations of gas transmission and distribution pipeline operators and users in relation to third party access to their pipelines. It does not include upstream gas facilities.

123 The objective of enabling third party access to gas pipelines was to promote the development of an integrated pipeline network and thereby a competitive national market for gas.

124 The application ("coverage") of the Access Code to new pipelines is determined on a case by case basis by the relevant Government Minister, on advice from the National Competition Council (NCC), although it is open to service providers to themselves request coverage of the pipeline by proposing an Access Arrangement to the 'relevant regulator' (ACCC for transmission pipelines and Jurisdictional Regulator for distribution pipelines).

125 In order to recommend coverage, the NCC must be satisfied of all of the following:

(a) that access (or increased access) to services provided by means of the pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the pipeline;

(b) that it would be uneconomic for anyone to develop another pipeline to provide the services provided by means of the pipeline;

(c) that access (or increased access) to the services provided by means of the pipeline can be provided without undue risk to human health or safety; and

(d) that access (or increased access) to the services provided by means of the pipeline would not be contrary to the public interest.

126 Any person can appeal a decision regarding Access Code coverage of a pipeline to the Tribunal.

127 The Code provides for pipeline owners to charge 'reference tariffs', approved by the relevant regulator. Reference tariffs set a benchmark for maximum prices for standard or 'reference' network services. Pipeline operators and users are free to negotiate alternative tariffs and services, but the reference tariff is the default to apply in the event of dispute. The overarching requirement for reference tariffs to be approved by the relevant regulator is that they reflect the efficient cost of providing the reference service.

128 The other principal regime for third party access to natural gas pipelines is Part IIIA of the *Trade Practices Act* 1974 (Cth) (TPA).

129 The criteria for coverage of a pipeline under the Access Code are similar, but not identical to those listed under Part IIIA. In particular, Part IIIA requires that the relevant pipeline be of national significance. This means that pipelines that are not subject to declaration can still be covered under the Access Code.

3.3.2. Interconnection developments

130 Historically, Australia's gas industry was developed on a State basis, with limited interconnection between systems. However, in recent years, new interconnectors have been developed to facilitate greater trade between States. A snapshot of the 1990's and the current arrangements confirm the significant gas pipeline developments that have occurred in the intervening period.

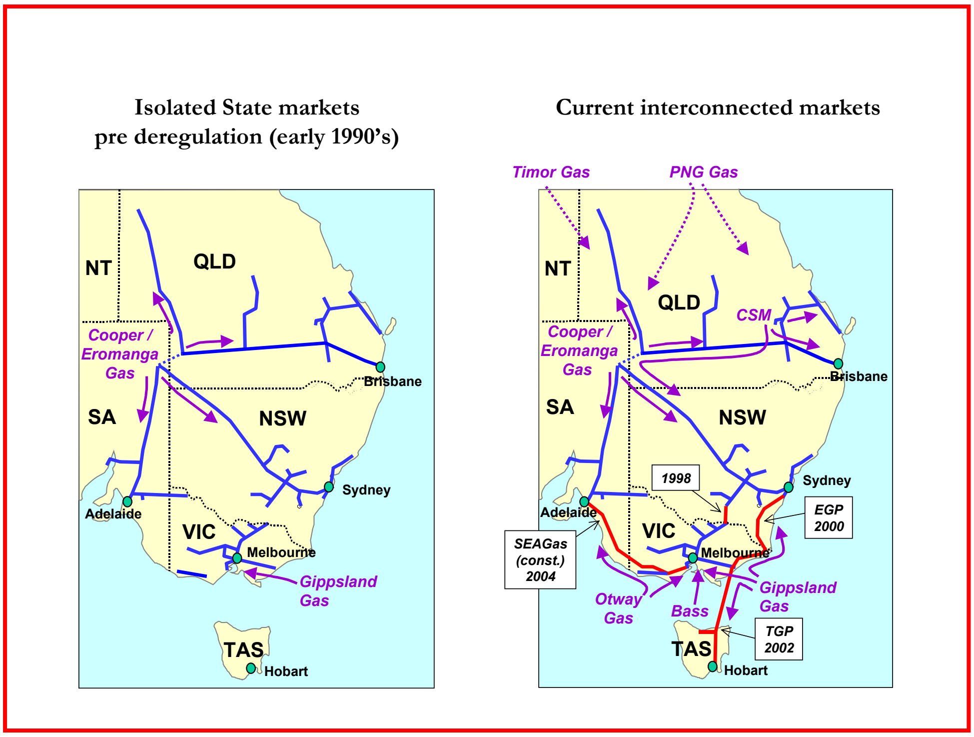

Figure 3:Eastern Australian gas market developments

Pipelines	PJ/yr
Existing major transmission pipelines	
Moomba (Cooper) to Young	152
Young to Sydney	152
Interconnect (north/south)	19/8
Moomba (Cooper) to Adelaide	120
Port Campbell (Otway) to Melbourne	95
Longford (Gippsland) to Melbourne	420
Longford (Gippsland) to Sydney	65
Moomba (Cooper) to Ballera/Mt Isa	50
Wallumbilla (Bowen-Surat) to Brisbane	38
Palm Valley (Amadeus) to Darwin	30
Dampier (Carnarvon) to Bunbury	200
Port Campbell (Otway) to Adelaide	125[1]
Proposed major transmission pipelines	
Bayu Undan (Timor Sea) to Darwin	250
PNG to Gladstone	200
Mt Isa to Townsville/Gladstone	100

Table 7: Existing eastern Australian pipeline capacity

131 Key pipeline developments that have contributed to an increase in competition in the supply of gas include[85]:

- in 1998 the Culcairn interconnect allowed gas to flow between Victoria and NSW for the first time by connecting the Victorian transmission system with the Moomba to Sydney Pipeline;
- in 1999 the South West Pipeline which connects the Western Underground Gas Storage System at Iona to the Victorian Transmission system;
- in 2000, the Eastern Gas Pipeline was completed between Longford in Victoria and Sydney, primarily to move gas from the Gippsland field to the NSW market. The pipeline had a capacity of 65 PJ per annum;
- The Tasmanian gas pipeline will transport natural gas from Victoria;

[85] KPMG, *CoAG Energy Market Review – Separate Marketing of Natural Gas in Australia*, October 2002.

- The SEAGas pipeline with estimated capacity of at least 50PJ per annum which connects Victoria to Adelaide and provides the opportunity for competition between the Otway gas supplies and other States; and
- The development of the VicHub at Longford, which connects NSW, Victoria and Tasmania provides for physical and financial trading in gas at an estimated capacity of 47 PJ per annum.

132 Australia's pipeline infrastructure exceeded 90,000 km in 2001, linking 3.5 million customers. In the five years to June 2000 over 13,000 km of natural gas reticulation and transmission pipelines were laid.[86] Additional transmission pipelines have been laid since this time adding to greater opportunity for customers to access gas and encourage inter-basin competition.

3.3.3. Competitive market developments

133 The impact of the expansion of the gas transmission system on competition is noted in The Council of Australian Governments Energy Market Review report, which stated:

> significant new pipelines have dramatically enhanced gas supply flexibility and therefore promoted the development of a more competitive market.[87]

134 As a consequence of the expansion of the pipeline network gas is now available to a significant proportion of households. In 2002 gas was provided to around 3.4 million households and 105,000 commercial and industrial customers.[88] With the significant development in pipelines since then, gas penetration into households is expected to continue, particularly in Queensland and New South Wales where the use of gas has historically been lower.[89]

135 Alinta, the owner of the Queensland Gas Pipeline, in association with other pipeline operators, has facilitated the creation of a pipeline hub linking three of Queensland's major gas pipelines. These include the Ballera to Wallumbilla, Wallumbilla to Brisbane and Wallumbilla to Gladstone pipelines. This means gas from the supply basins connected to the Queensland Gas Pipeline can feed the major market of south-east Queensland and the mining region in the State's north-west around Mt Isa. In the future, this could become an active trading hub where gas is traded between other state markets.

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86 AGA, Gas statistics 2001, pg 70.

87 COAG, Towards a Truly National and Efficient Energy Market, December 2002, pg 187.

88 AGA, Gas Statistics Australia, 2002. pg 45-46.

89 Australian Gas Association, *Gas Statistics 2001*

136 Depending on the volumes contracted with the PNG Gas Pipeline the network is likely to have some excess capacity, which will be available for third parties to utilise and provide the opportunity for greater competition in the supply of gas.

137 The opportunities for third parties to utilise the PNG pipeline include domestic CSM producers, thus allowing these producers access to a broader market; and other gas producers in PNG, increasing the diversity of suppliers into the Australian market.

138 We also understand that, if the Participants' Project does proceed, it will include a link between Ballera and Moomba. The construction of this link will allow southern suppliers to ship gas into Queensland and therefore represents and important addition to the national gas pipeline infrastructure providing additional scope for inter-basin competition.

139 This proposed link would confirm the development of the eastern gas market as anticipated by the Tribunal and highlights the value of the Project in the evolution of the gas industry in Australia.

4. Implications of the emerging patterns in energy markets for the PNG Joint Venture

140 The natural gas markets in Australia were historically State based and in the past could have been be characterised as a single producer transporting the gas to a single seller via a point-to-point transmission network. There was little or no choice for buyers of supplier or the path of delivery.

141 However, as outlined in Section 3.2, gas customers increasingly have access to multiple suppliers of gas including conventional natural gas, CSM, CMM and smaller landfill gas opportunities throughout eastern Australia. This increase in choice of supplier is enhanced by the expansion and interconnection of the gas transmission system. These developments have increased the competitiveness of the gas market.

142 The Project will enhance the competitive pressures of gas suppliers by providing an additional significant source of supply, not only into the Queensland market, but also through pipeline interconnection throughout the rest of Eastern Australia. The pipeline will also provide further opportunities to provide fuel-on-fuel competition to regions that do not currently have access to gas. In addition, the pipeline will provide the trunkline for other suppliers to continue to construct spur lines linking gas fields to the main transmission network as has already occurred in Queensland. This would further enhance the competitiveness between gas fields across eastern Australia.

143 However, as indicated in Section 2.3 the project timing is dictated by the need to obtain, synchronously, sufficient volume commitments from foundation customers. To date the Project has struggled to obtain and retain commitments for sufficient volumes for the Project to proceed quickly. The subsequent delay in being able to finalise a commissioning date has lead to greater uncertainty surrounding the Project and this uncertainty has compounded the difficulties in being able to obtain foundation customers.

144 A major problem for the Participants is that they face competition from alternative suppliers of gas, allowing potential customers to pursue alternatives if they detect a better deal.

145 CSM gas has proven to be a successful competitor in being able to capture the Project's potential customers. As stated earlier, CSM gas supplies have a competitive advantage over conventional gas supplies since they are generally closer to the market and therefore incur lower transport costs for customers. This transport cost advantage increases the potential for CSM to compete with conventional natural gas suppliers.

146 AGL, in their submission to the CoAG Energy Market Review, indicated that the final gas price could be decomposed into the following components:

- 64 per cent well-head price for gas;
- 21 per cent transmission;
- 11 per cent distribution; and
- 4 per cent retail.

At least a proportion of the transmission costs (which h represents 21 per cent of costs) could be saved from the use of a CSM supplier in closer proximity to the user.

147 Another advantage that CSM gas has over the PNG Project is the development costs associated with the Project and the availability of CSM. It has been suggested that the availability of CSM is around 2,300 PJ.[90] Customers compare the ready access to CSM supplies to the prospect of a natural gas supplied from infrastructure that is yet to be built.

148 This competition between CSM and conventional natural gas supplies can already be demonstrated via the recent AGL contract with Sydney Gas Company. This competition between gas reserves in different States has been assisted by the pipeline reforms; third party access and the expansion of the pipeline network.

149 The ability of the Project to acquire customers is also hampered by the lack of liquidity in demand. As described in section 3.1.5, there are only five major gas retailers and less than forty other customers the Project could potentially negotiate with.

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90 JP Morgan, Utilities Markets – Gas Markets Reviewed, Electricity Customer Churn Plateaus, 15 October 2004.

5. Implications for the determination of relevant markets

150 This paper took its lead from the decision of the Tribunal and the Federal Court in the two AGL cases. Each of these decisions emphasised the evolving nature of the relevant markets and the need to take a long-term view when assessing mergers or long-term contractual arrangements. Both of these lessons apply to this Application for authorisation.

151 Since these decisions, the east coast gas and electricity markets have continued to evolve; and the links between them have become stronger. The links within both markets across geographical space have become stronger; and this trend can be expected to continue. Legislation on greenhouse gas emissions has appeared since the decision of the Tribunal. The data show that there is considerable growth in the demand for gas, driven in part by this legislation.

152 On the supply side, we observe that gas supply and basin diversity has increased significantly in recent years. Both the developments on the demand side and on the supply side have been assisted by the significant investment in pipeline capacity in Australia in recent years.

153 In drawing conclusions on the definition of market we are assisted by the process expounded in *QCMA* where the Tribunal defined the market as the area of close competition between firms. The Tribunal observed that substitution occurs within a market between one product and another, and between one source of supply and another in response to changing prices:

> So a market is the field of actual and potential transactions between buyers and sellers amongst whom there can be strong substitution, at least in the long run, if given a sufficient price incentive. (at 190)

154 In the current case of the PNG Project, the fraught history of negotiations with potential foundation customers clearly identifies the existence of substitution possibilities. The Participants pursued a number of potential customers, and in a number of cases non-firm contracts were negotiated. However, a significant number of these potential customers opted to obtain their gas supplies from an alternative supplier. The scope for competition has been amply demonstrated by the practical difficulties that the Participants have faced in securing foundation customers. The emergence of new sources of gas supply, such as CSM, and increasing investment in pipelines, have also provided sources of competition.

155 The availability of alternative sources of supply and ease of substitution between suppliers drive the conclusion that the relevant market should be defined no more narrowly that the market for natural gas (including coal seam methane) in eastern Australia, which includes Queensland, New South Wales, Victoria and South Australia.

156 The geographic dimension of the market recognises the degree of interconnection across the eastern jurisdictions and the other market developments documented in this report.

157 The life of the project, if it proceeds, will be at least 30 years. Any decision to proceed with the project will take into account competitive constraints that the project will face over that period. Any analysis of the competitive constraints that confront the project must adopt a similar time horizon. It is impossible to be at all precise about the state of competition in any market decades in advance. Nevertheless, one can say with confidence that the trends of increased competition across geography and across different sources of energy that have occurred during the last decade will continue for some considerable time.

158 In conclusion, it seems to us that in considering the competition that the proposed JV is likely to face, the appropriate market is a gas (including CSM) market embracing at least the east coast of Australia. As the Tribunal in the Cooper Basin determination noted, competition among alternative sources of energy already exists on the boundaries to the gas market. It is reasonable to predict that these forms of competition will become much more central – in particular if trends brought about by greenhouse gas legislation continue.

6. Attachment 1 – Potential customers

List of pipeline potential customers

Source: Allens Arthur Robinson.

[Confidential information redacted]

Attachment 1 – Potential customers