MOOMBA TO SYDNEY PIPELINE SYSTEM:

REVOCATION APPLICATIONS UNDER THE NATIONAL GAS CODE

Final Recommendations

November 2002

National Competition Council

Contents

1 Executive summary

1.1 The National Competition Council received applications in June 2001 to revoke two pipelines within the Moomba to Sydney Pipeline System from coverage under the National Third Party Access Code for Natural Gas Pipeline Systems (**National Gas Code**). The applications were made by East Australian Pipeline Limited (**EAPL**), the owner of the pipelines.[1]

1.2 The Moomba to Sydney Pipeline System transports natural gas from Moomba (in South Australia) to Wilton (just outside Sydney) and via transmission laterals to regional New South Wales (**NSW**) and the Australian Capital Territory (**ACT**). The system joins with the Victorian gas transmission system near Wagga Wagga, enabling the transportation of gas in either direction between NSW and Victoria.

1.3 EAPL is seeking revocation from coverage of two pipelines within the Moomba to Sydney Pipeline System:

(a) the main pipeline running from Moomba to Wilton, (the **MSP Mainline)**; and

(b) the transmission lateral branching off the MSP Mainline at Dalton and running to North Watson in Canberra (the **Canberra Lateral)**.

1.4 In considering the applications, the Council has applied the criteria set out in s.1.9 of the National Gas Code. To assist its consideration, the Council sought the views of stakeholders and met with interested parties.

1.5 The Council also considered work undertaken by Professor Janusz Ordover (New York University) and Dr William Lehr (Massachusetts Institute of Technology) on questions raised by criteria (a) and (b) of s.1.9 of the National Gas Code.

1.6 The Council sought legal advice on vertical linkages between EAPL and other businesses in the gas supply chain. In addition, the Council sought advice from the Australian Competition and

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1 EAPL is wholly owned by the Australian Pipeline Trust.

Consumer Commission (**ACCC**) on a number of technical issues raised in a joint submission from EAPL and Network Economics Consulting Group (**NECG**). The ACCC subsequently engaged National Economic Research Associates (**NERA**) to critique some aspects of the submission.

1.7 Following consideration of all submissions and other consultation with stakeholders, the work of Ordover and Lehr, technical advice from the ACCC, the NERA report (and submissions on the advice and report), and legal advice on vertical linkage issues, the Council is satisfied that the whole of the MSP Mainline and Canberra Lateral satisfy all of the criteria in s.1.9 of the National Gas Code. The Council therefore recommends that coverage of the MSP Mainline and Canberra Lateral under the National Gas Code should not be revoked.

1.8 The principal issues arising under each of the s.1.9 criteria are summarised below.

Criterion (b)

that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline

1.9 EAPL has not relied on criterion (b) to support its applications to revoke coverage of the MSP Mainline and Canberra Lateral.

1.10 The Council considers that criterion (b) is satisfied if a single pipeline can satisfy demand for the relevant service at lower cost than two or more pipelines. The relevant pipeline is then a natural monopoly, and competition between two or more pipelines offering the same services would be inefficient.

1.11 The services of the MSP Mainline and Canberra Lateral are the transport of natural gas from the production fields in the Cooper Basin to gas sales markets in NSW and the ACT:

(a) the *MSP Mainline* provides natural gas transport services from Moomba to Wilton (Sydney) as well as to points in between including the exit flanges for various laterals along the length of the MSP Mainline (such as the Canberra Lateral); and

(b) the *Canberra Lateral* provides natural gas transport services from Dalton (the relevant exit flange on the MSP

Mainline) to North Watson in the Australian Capital Territory as well as to points in between.

1.12 For another pipeline to provide the services of the MSP Mainline and Canberra Lateral, the pipeline would have to transport natural gas between the Cooper Basin gas fields and gas sales markets in NSW and the ACT. No other pipelines currently provide the point-to-point transport services of the MSP Mainline or Canberra Lateral.

1.13 Criterion (b) turns on the cost function associated with meeting demand for the relevant services. The Council notes that gas transmission pipelines typically exhibit natural monopoly characteristics. This is because the costs of constructing and operating a pipeline are largely sunk and fixed, while the variable costs of increasing output are relatively small. These characteristics mean that the average cost of transporting an additional unit of gas normally declines until the fully expanded capacity of a pipeline is reached. In other words, it is almost always cheaper to transport gas through an existing pipeline (up to the point of fully developed capacity) than to build a new pipeline to provide the relevant service(s).

1.14 Moreover, the high sunk costs of constructing additional pipelines serve as a barrier to the entry of new pipelines. 'Sunk costs' are those elements of an investment that are fixed or committed, and where, if the investment fails, little or none of the investment can be recovered. The presence of sunk costs also means that incremental or gradual entry – a common form of entry in other industries – is not feasible in gas transmission services.

1.15 The Council has not seen evidence to suggest that the MSP Mainline and Canberra Lateral do not exhibit these cost characteristics.

1.16 Consistent with the Tribunal's approach in the *Duke EGP decision*, the relevant range of output for assessing whether the MSP Mainline and Canberra Lateral are natural monopolies in the provision of services between the Cooper Basin fields and NSW/ACT is the maximum foreseeable demand for relevant services over the next 10 to 15 years.

MSP Mainline

1.17 Based on EAPL forecasts accepted by the ACCC, the Council considers that the maximum foreseeable demand for MSP Mainline services over the next 10 –15 years is about 200 PJ per year.

1.18 Based on information provided by EAPL, the Council accepts that the maximum potential capacity of the MSP Mainline is at least 290 PJ/a.

1.19 The Council notes that the maximum potential capacity of the MSP Mainline (at least 290 PJ/a) exceeds the maximum potential demand for the services of the pipeline (about 200 PJ/a) over the next 10 –15 years. The economics of pipeline construction would suggest that building two (or more) point-to-point pipelines, each carrying only a share of these forecast volumes would be uneconomic. Given the current and anticipated state of demand, it is therefore reasonable to conclude, on cost criteria alone, that the MSP Mainline is a natural monopoly for the provision of transport services for natural gas between Moomba and Sydney.

1.20 In view of the expandable capacity of the MSP Mainline and the relatively modest costs of expansion compared to the costs of developing another pipeline; and the forecast demand for services in the next 10 – 15 years, the Council concludes that it would not be economic to develop another pipeline to provide the services of the MSP Mainline. The Council therefore finds that the MSP Mainline satisfies criterion (b).

Canberra Lateral

1.21 The Canberra Lateral has a current capacity of around 16.8 PJ/a (EAPL 1999b, p.32). In 1999, EAPL reported that 16.4 PJ/a was contracted. It was also forecast that peak day demand would outstrip capacity in 2001, and would rise to 18.2 PJ/a in 2005 (EAPL 1999b, p.32).

1.22 In 1999 EAPL proposed expanding the capacity of the Canberra Lateral to cope with rising demand through partial looping, at a cost of around $3.458 million (EAPL 1999b, p.33). This would increase capacity to 21.2 PJ/a (EAPL 1999b, p.34). This equates with an incremental cost to expand the Canberra Lateral of less than $800,000 per PJ/a in additional capacity. On EAPL's forecast volumes, this capacity expansion would have satisfied 2005 peak day demand with some spare capacity.

1.23 The Council notes that the proposed capacity expansion of the Canberra Lateral is within the maximum expandable capacity of the pipeline. It has not been proposed by any party that development of another pipeline between Dalton to Canberra could add capacity up to 21.2 PJ/a at lower cost than expansion of the Canberra Lateral. Given the cost characteristics of gas pipelines noted above, the Council accepts that the Canberra Lateral is likely to exhibit declining costs over the range of output up to at least 21.2 PJ/a and that it would be uneconomic to develop another pipeline to provide the services of the Canberra Lateral up to at least 21.2 PJ/a.

1.24 The Council notes that the proposed expanded capacity of the Canberra Lateral (21.2 PJ/a) exceeds forecast 2005 peak day demand. The economics of pipeline construction would suggest that building two (or more) point-to-point pipelines, each carrying only a share of these forecast volumes would be uneconomic. Given the current and anticipated state of demand, it is therefore reasonable to conclude, on cost criteria alone, that the Canberra Lateral is a natural monopoly in the provision of transport services for natural gas between Dalton and Canberra.

1.25 In view of the expandable capacity of the Canberra Lateral and the relatively modest costs of expansion compared to the costs of developing another pipeline; and the forecast demand for relevant services in 2005, the Council concludes that it would not be economic to develop another pipeline to provide the services of the Canberra Lateral.

1.26 The Council therefore finds that the Canberra Lateral satisfies criterion (b).

Criterion (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

1.27 The *Duke EGP decision* found that criterion (a) turns on the ability of a pipeline to exploit market power in a dependent market. There is evidence that the MSP Mainline and Canberra Lateral (**MSP**[2]) have the ability and incentives to exploit market power in dependent markets, to the detriment of competition, through:

(a) monopoly pricing; and

(b) vertical leveraging.

Monopoly pricing

1.28 A natural monopoly gas pipeline may be able to exploit its market power by setting prices for transport services that substantially exceed long-run economic cost.

1.29 The MSP Mainline and Canberra Lateral exhibit high fixed costs relative to incremental costs. The MSP also has substantial spare capacity. These factors, in themselves, are likely to create incentives for high rates of throughput. Nonetheless, there is a risk of monopoly pricing and associated restrictions in output if the pipeline has substantial market power. According to Ordover and Lehr, the critical determinant of whether monopoly pricing will be profitable to the MSP is whether there is effective competition in dependent markets to constrain such behaviour (Ordover and Lehr 2001, p.23).

1.30 In delineating dependent markets, the Council has identified:

(a) an upstream gas sales market for gas produced in the Cooper Basin, involving transactions between producers in the Cooper Basin and parties able to buy gas directly from that gas field; and

(b) downstream gas sales markets in Sydney, Canberra, and places along the route of the MSP, involving transactions between gas sellers and end users of natural gas.

1.31 In the *upstream* market, the MSP's ability to exploit market power turns on whether the Cooper Basin producers have viable options to divert gas sales into other markets in the event of monopoly pricing by the MSP. The only viable alternative at present – the Moomba to Adelaide pipeline – is capacity constrained. While this may change

2 The MSP Mainline and Canberra Lateral are separate pipelines for the purposes of this report, and the Council makes separate recommendations for each. For the sake of brevity, the abbreviation 'MSP' is used in parts of this report to jointly refer to the MSP Mainline and Canberra Lateral.

from about 2004, it appears that South Australia's gas demand is not growing fast enough to absorb the sales diversions needed to constrain MSP pricing. Nor is there likely to be scope to divert gas sales into Queensland markets in the foreseeable future. Absent coverage, the MSP is therefore likely to have scope to charge monopoly tariffs for shipping Cooper Basin gas.

1.32 Monopoly pricing for MSP services is likely to result in higher delivered prices for gas (which would weaken demand for gas) and/or lower returns in gas production. These conditions are likely to reduce gas production and distort entry incentives in the upstream market, weakening the competitive environment in that market.

1.33 In *downstream* markets, the MSP's ability to monopoly price turns on whether customers are able to switch to alternative sources of gas supply at a competitive price, in the event of monopoly pricing on the MSP. There are signs of emerging competition in downstream gas sales markets in Sydney and Canberra since the opening of the Eastern Gas Pipeline (**EGP**). However, there is no evidence that downstream markets are effectively competitive at present. All parties, including Duke and EAPL, have agreed that downstream competition is an evolving process.

1.34 The *Duke EGP decision* referred to competition between pipelines as a constraint on EGP pricing. However, it is not clear that this finding would apply to the MSP – despite the fact that both the MSP and EGP supply gas into Sydney and Canberra markets:

(a) First, the Tribunal's decision was made against the context of the MSP being a covered pipeline. In that environment, the competitive constraint on the EGP may have been relatively potent, as MSP tariffs were expected to be regulated by an independent regulator under the National Gas Code.

(b) Second, the Tribunal relied on an estimate of a high cross-price elasticity of demand between the Interconnect and the EGP. Each of these pipelines provides a service between Longford and Sydney (and between various locations along their respective routes).[3] The Council details evidence in

3 When the Council refers to the Interconnect as providing a service between Longford and Sydney, it is using shorthand to describe a service provided by a combination of pipelines between Longford and Sydney, incorporating: the

this report that this cross-price elasticity estimate may be unreliable. Further, there is no empirical evidence on the cross-price elasticity of demand between the MSP and other pipelines. Given that the MSP is the only pipeline that ships gas between Moomba and Sydney, there is likely to be less scope for substitution between the MSP and other pipelines, than between the EGP and the Interconnect.

1.35 Evidence on pricing suggests that the MSP does not face an effective competitive constraint from other pipelines. Since 2000, MSP tariffs to Sydney have fallen, while EGP tariffs to Sydney have risen – that is, tariffs are becoming more divergent. This gap will widen further[4] when EGP tariffs rise on 1 January 2003. These price trends are not indicative of vigorously competing pipelines.

1.36 More generally, there is a lack of evidence of NSW/ACT gas consumers actively moving demand among sources of gas supply in response to price movements. While construction of the EGP may have resulted in some loads switching from the Cooper Basin/MSP to Gippsland Basin/EGP, the Council understands that a substantial proportion of EGP volumes are carried for foundation shippers. Evidence was provided to the Council in August 2001 that apart from foundation shipments, about 5 PJ had been transferred since 2000 – about 5% of MSP loads.[5] Further, there is little evidence of effective competition at the retail level. In Sydney, there is only one active retailer independent of AGL, and none in Canberra. The NSW Government has warned that monopoly pricing behaviour may remain an issue for some time.

1.37 The MSP's ability and incentive to monopoly price may be especially potent in regional markets, where the MSP is the only transmission pipeline for gas deliveries. In these markets, the lack of supply alternatives enhances the ability of the MSP to price above efficient cost.

1.38 The Tribunal found in the *Duke EGP decision* that monopoly pricing was unlikely to be a significant threat in regional areas along the route of the EGP. However, the Council notes that the circumstances

Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline.

4 Unless MSP tariffs also rise. See also footnote 9.

5 Based on published forecasts for 2001, ACCC 2000b, p.91.

of the MSP differ from those of the EGP. In particular, the EGP faces commercial incentives to develop new markets in areas where gas was not previously available, and where gas consumers would need to be diverted from established energy sources. In contrast, regional markets along the route of the MSP are established markets that have been served by the pipeline for over 20 years. Hence, the MSP may not face the same commercial imperatives to develop new markets through efficient tariffs as may be faced by the EGP.

1.39 Collectively, this evidence suggests that downstream gas sales markets are not sufficiently competitive to constrain MSP pricing. The MSP is therefore likely to have sufficient market power to charge monopoly tariffs to downstream pipeline users.

1.40 If monopoly tariffs are passed on to customers as higher delivered gas prices, the demand for gas is likely to fall. This would weaken entry incentives in downstream gas sales markets, resulting in a less competitive environment in those markets.

1.41 Alternatively, if downstream gas sellers absorb a share of monopoly tariffs, the impact on delivered gas prices would be constrained. However, lower returns would reduce incentives to invest in downstream markets, with adverse consequences for the competitive environment.

1.42 MSP pricing outcomes provide corroborative evidence that competition in dependent markets is not sufficiently effective to constrain tariffs:

(a) The ACCC draft decision on the MSP access arrangement indicates that current MSP tariffs are about 32% above the tariffs allowable under the National Gas Code.[6] The Tribunal noted in the *DEI Queensland Pipeline decision* that the objectives listed at s.8.1 of the Code include “replicating the outcome of a competitive market,” and affirmed that this involves prices that reflect efficient costs as well as non-price attributes tailored to what customers want. The Council notes that the ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code.

6 Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005, adjusted to reflect recent changes in the ACCC’s approach to deferred tax liabilities ($0.50/GJ).

(b) Modelling of MSP costs with regard to the investment actually made by the infrastructure owner (the 1994 purchase price, adjusted for subsequent investment) would result in current MSP tariffs being about 28% to 50% higher than tariffs derived from an initial capital base that reflects the 1994 purchase price.[7]

(c) An estimate by NERA of MSP tariffs that would apply under hypothetical new entrant pricing, found that current MSP tariffs are about 29% above contestable market prices.[8]

1.43 The Council notes that current MSP prices exceed cost based prices and contestable market pricing by significantly more than what would ordinarily be considered as an error margin.

1.44 The Council accepts that there are a number of alternative methods for deriving efficient pipeline tariffs, and that “competitive” prices are notoriously difficult to estimate in network industries characterised by significant fixed costs and low variable costs. However, the combined evidence on cost estimates indicates that current MSP tariffs are likely to be significantly above long-run economic cost – the level they should attain in the presence of effective competition. This reinforces the likelihood that the MSP is able to exploit market power in dependent markets. It also provides evidence that the MSP may be currently exercising that power.

Would coverage promote competition in dependent markets?

Upstream market

1.45 As set out above, the Cooper Basin producers do not have viable options to constrain monopoly pricing on the MSP. The ACCC and NERA analysis reinforce this finding. An effect of coverage would be to remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide upstream producers and gas buyers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The ACCC draft

7 Based on valuation estimates in the ACCC draft decision on the MSP access arrangement: ACCC 2000b, p.41. The range reflects alternative assumptions about depreciation.

8 Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against NERA estimate of hypothetical new entrant pricing of $0.51/GJ.

indicative tariffs (adjusted) indicate that this price is likely to be significantly lower than prices absent coverage. [9]

1.46 If lower tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand would stimulate higher rates of production, creating incentives for new entry in the upstream market to satisfy that demand. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).

1.47 If upstream producers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns will encourage new entry in the upstream market. The threat or event of new entry, in turn, would promote rivalrous behaviour in that market. Indeed, the reduction in impediments to entry could stimulate more competitive behaviour among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a).

1.48 The Council therefore considers that coverage is likely to promote upstream competition regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by upstream producers.

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9 The gap between MSP tariffs (absent coverage) and MSP tariffs (with coverage) may continue to widen over time. The Council observes that the EGP Longford to Sydney tariff rose by about 6% on 1 January 2002, raising the price of delivered Gippsland Basin gas relative to delivered Cooper Basin gas. EGP tariffs will escalate once again on 1 January 2003, with ongoing annual escalations in accordance with a formula based on movements in the Consumer Price Index (Duke Energy 2001b)

The Council notes the possibility that the EGP could raise its tariffs without increasing the price of delivered Gippsland Basin gas in Sydney, if Gippsland Basin well-head gas prices were falling. However, there is no evidence that EGP tariffs are rising for this reason. Annual price rises for EGP services are predetermined in the EGP's firm forward haulage service contract terms sheet (Duke Energy 2001b).

It is likely, therefore, that annual escalations in EGP tariffs are weakening whatever discipline the EGP may previously have applied to MSP tariffs. Absent coverage, this may allow scope for the MSP to increase tariffs by an equivalent margin to the EGP without risking a loss of sales. This would widen the gap between MSP tariffs absent coverage and the regulated tariffs that would apply if the MSP was covered.

1.49 The Council has examined claims that the promotion of competition arising from coverage may be immaterial. The Council considers that these claims rely on understated estimates of relevant demand elasticities and understate the relative significance of transmission tariffs in delivered gas prices.

1.50 The Council has also examined claims that any promotion of competition in the upstream market would be defeated by barriers to competition related to acreage management. The Council has found that acreage management policies have been progressively reformed since 1999, and has noted new entry in the Cooper Basin of several producers independent of the incumbents. Over time, these parties may exercise increasing discipline on the upstream market, stimulating increased gas production in the Cooper Basin and, possibly, greater diversity among gas producers in the long run.

1.51 Coverage of the MSP is likely to encourage ongoing new entry in the Cooper Basin by improving commercial prospects for selling gas. In the event of large discoveries, coverage would provide a means for gas to be shipped to customers on competitive terms. If discoveries are small, new entrants may prefer to sell gas to incumbent producers. Once again, coverage would improve commercial prospects for new entrants by providing them with a degree of countervailing power in negotiations with incumbent producers. For these reasons, coverage is likely to encourage new exploration activity, competition between new entrants and incumbent producers and higher rates of gas production. These would be pro-competitive outcomes.

Downstream markets

1.52 The Council has found that while competition is emerging in downstream gas sales markets, those markets are not yet sufficiently competitive to constrain MSP pricing. The ACCC and NERA analysis reinforce this finding.

1.53 An effect of coverage would be to remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide downstream gas sellers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The

ACCC draft indicative tariffs (adjusted) indicate that this price is likely to be significantly lower than prices absent coverage.[10]

1.54 If lower transport tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand create incentives for new entrants to invest in downstream gas sales markets to satisfy that demand, thus promoting a more competitive environment in those markets. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).

1.55 Alternatively, if downstream gas sellers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns in gas sales markets will encourage new entry. The threat or event of new entry, in turn, would promote rivalrous behaviour in those markets. Indeed, the reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a). Over time, rivalrous behaviour between new entrants and incumbents is likely to compete away downstream rents, such that delivered gas prices will fall.

1.56 The Council concludes that coverage would promote downstream competition regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by downstream gas sellers.

1.57 The Council has examined claims that this promotion of competition may be immaterial. The Council considers that these claims are based on underestimates of relevant elasticities and understate the relative significance of transmission tariffs in delivered gas prices

Vertical leveraging

1.58 A pipeline with monopoly power over transport may seek to leverage its market power into upstream or downstream markets, to maximise profits. Specifically, if a pipeline has ownership interests in upstream or downstream markets, it may have an incentive to discriminate in favour of affiliates.

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10 See footnote 9.

1.59 Discrimination can manifest in a variety of ways, including the charging of lower prices to affiliates for transport services; or offering services on unequal and inferior terms to non-affiliates in upstream or downstream markets.

1.60 Vertical leveraging of this kind may hinder competition in dependent markets. In particular, it may deter the prospect of entry by independent parties into those markets.

1.61 The Council considers that there may be economic incentives for the MSP to distort competition in downstream markets arising from the interest AGL has in both the MSP and in AGL Wholesale Gas Limited (**AGLWG**). The Council considers that, to the extent to which the MSP is part of a vertically integrated entity, it may seek to extend, protect or exploit whatever market power AGL may have in downstream markets.

1.62 Alternatively, the owners of the MSP may seek to assert influence over Australian Pipeline Limited(**APL**)/Australian Pipeline Trust (**APT**)/MSP so as to advantage AGL's downstream interests, where such influence is permissible under the legal constraints including Corporations Act, Listing Rules and corporate governance of APL/APT. That is, AGL, as the 30% beneficial owner of the MSP, may seek to assert its rights as the major unit holder to cause the MSP to act in a manner which gives an advantage to AGLWG or which disadvantages AGLWG's competitors, for example, by increasing MSP tariffs charged to those parties.

1.63 Regardless of whether AGL controls APL and EAPL within the meaning of the Corporations Act and Listing Rules, the Council considers that there is a very close relationship between AGL and APL/APT/EAPL and that the extent of AGL’s interests in APL/APT/EAPL and APT/EAPL’s dependence on AGL creates an incentive for APT/EAPL to act in AGL’s interests (provided that in so doing it is also acting in the interests of the unit holders as a whole).

1.64 The Council considers that APL, as a matter of law, can discriminate in favour of AGL's interests upstream or downstream, provided such discrimination is not against the interests of all the unit holders in APT. In the Council’s view, the legal restrictions on discriminatory behaviour are unlikely, in many circumstances, to constrain the MSP from acting in a manner to advantage its affiliates and so distort competition in downstream markets.

1.65 The Council considers that the Gas Transportation Deed (**GTD**) between EAPL and AGLWG may provide a means by which the MSP can act in a manner which advantages AGLWG in downstream markets. At the very least, the Deed is consistent with EAPL favouring AGLWG. The Council notes that the GTD has been approved by the ACCC as an associate contract under the National Gas Code. The ACCC approved the GTD in the context of the MSP being a covered pipeline with a regulated reference tariff.

1.66 The Council considers that currently, and until 2006, the effect of the GTD is that the terms on which EAPL provides transportation services to AGLWG are more favourable than the terms upon which those services may be supplied to third parties. In particular, the Deed reserves **[confidential information]**, thus limiting the capacity available to potential third parties. In addition, AGLWG receives the benefit of most favoured customer pricing provisions, and until 31 December 2002, benefits from revenue sharing from third party sales.

1.67 From 2007 to 2016, the GTD guarantees AGLWG reserved capacity equal to about 34% of the current installed capacity of the MSP. The most favoured customer provisions continue to apply, to the effect that the tariff paid by AGLWG is the lower of the Published Reference Tariff or the lowest price paid by a third party for comparable services.

1.68 Absent coverage, the Council considers that this preference for AGLWG would continue, or may be enhanced, with the important difference that there would be no right for third parties to negotiate access to MSP services on the competitive terms and conditions (including a reference tariff) approved by the ACCC.

1.69 Given that AGLWG currently ships **[confidential information]**of expected MSP deliveries, **[confidential information]**, there seems little risk of decreased demand for MSP services by its major customer if the MSP increased the price of transport, at least until 2006. Given the ownership interest of AGL in APT and AGLWG, it is also likely that there is little risk of the MSP losing AGLWG as a customer after the expiry of the GTD (assuming the current ownership structure is maintained).

1.70 Absent coverage, the provisions of the GTD may therefore give the MSP incentive to distort competition in downstream gas sales markets because it has a guaranteed customer for **[confidential information]** and 34% of capacity from 2007 – 2016. This creates little incentive for the owners of the MSP to sell transport services to third parties, particularly until 2006. Further, without the discipline imposed by coverage on MSP tariffs, EAPL would have the ability to increase the tariffs without loss of its major customer.

1.71 Absent coverage, competition in downstream markets may therefore be distorted due to:

(a) **[confidential information]**;

(b) the provision of transport services by the MSP to AGLWG on terms which are equal to the best terms negotiated by any other customer;

(c) the absence of a competitive tariff set by the ACCC; and

(d) the absence of a statutory right for third parties to negotiate for the provision of MSP transport services and a right to those services on the terms and conditions set out in an access arrangement approved under the National Gas Code.

1.72 The Council notes that the MSP's ability and incentives to distort competition would be constrained by a finding of effective competition in downstream markets. However, the Council has elsewhere provided evidence that downstream competition is still evolving, including evidence that MSP pricing is not constrained by effective competition.

1.73 While the GTD is likely to remain in place regardless of whether the MSP is covered, coverage mitigates the anti-competitive effects of the GTD by providing a right for third parties to negotiate access to spare capacity on the MSP, with a published tariff to discipline prices. Draft indicative MSP tariffs proposed by the ACCC are considerably lower than the current tariffs charged by EAPL. Coverage would also retain application of National Gas Code requirements on ring fencing and regulatory approval of associate contracts. In mitigating the anti-competitive effects of the GTD, and in disciplining MSP pricing, coverage would promote a more competitive environment in downstream markets.

Conclusion on criterion (a)

1.74 The Council concludes that coverage of the MSP Mainline and Canberra Lateral:

(a) would promote competition in upstream and downstream markets as a consequence of the ability and incentive of the pipelines to charge monopoly prices for transport services.

(b) would promote competition in downstream markets as a consequence of the ability and incentive of the pipelines to distort competition in those markets through vertical leveraging.

1.75 The Council therefore finds that the MSP Mainline and Canberra Lateral satisfy criterion (a).

Criterion (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

1.76 The Council did not receive submissions arguing that it would be unsafe to provide access or increased access to the services of the MSP Mainline or the Canberra Lateral. This is consistent with the Council's experience in relation to a number of applications seeking revocation of coverage of pipelines, where safety concerns were not raised to support revocation.

1.77 The National Gas Code contemplates the provision of access to pipelines throughout Australia under Gas Access Acts in each State and Territory. The Council is not aware of any instance where safety concerns have been raised in relation to access or increased access to the services of pipelines. Nor is there any available evidence to suggest that safety is a particular concern in relation to the provision of access or increased access to the services of the two pipelines for which revocation is sought.

1.78 NSW, South Australia, Queensland, and the ACT have passed regulations dealing with the safe operation of gas pipelines. The Council is confident that these regulations deal appropriately with any safety issues arising from access to the two pipelines.

1.79 The Council concludes that access (or increased access) can be safely provided to the services of the MSP Mainline and the Canberra Lateral. The Council therefore finds that the MSP Mainline and the Canberra Lateral satisfy criterion (c).

Criterion (d)

that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest

1.80 In the *Duke EGP decision*, the Tribunal clarified the interpretation of criterion (d) as follows:

> *... criterion (d) does not constitute an additional positive requirement which can be used to call into question the result obtained by the application of pars (a), (b) and (c) of the [coverage] criteria. Criterion (d) accepts the results derived from the application of pars (a), (b) and (c), but enquires whether there are any other matters which lead to the conclusion that coverage would be contrary to the public interest.* (Duke EGP decision 2001, paragraph 145)

1.81 The Council adopts a broad view of the types of matters that may raise public interest considerations under criterion (d), including the overall costs of regulation, and any effects that regulated access might have on the environment, regional development, and equity.

1.82 Because criterion (d) is phrased in the negative, a recommendation to revoke coverage would require that the costs of regulated access outweigh the benefits of regulating natural monopoly services with substantial market power. The extent of these benefits depends on the likely effect of regulating natural monopoly services on competition in related markets; issues considered under criterion (a).

1.83 The Council recognises that access regulation can have costs and inefficiencies. In applying criterion (d), the Council considers whether the costs of coverage outweigh the benefits. In making its current assessment, the Council has taken into account both the direct and indirect costs of regulation under the National Gas Code.

1.84 The following issues of relevance to criterion (d) were raised in submissions:

(a) covering the Moomba to Sydney Pipeline System (including the MSP Mainline and Canberra Lateral) while the EGP is uncovered raises concerns of asymmetric regulation;

(b) the costs of regulation; and

(c) the costs and benefits of the National Gas Code's information disclosure provisions.

Asymmetric regulation?

1.85 A number of submissions discussed whether it was appropriate to regulate the MSP Mainline and the Canberra Lateral in view of the decision of the Tribunal that the EGP should not be covered under the National Gas Code. It was argued that this would gave rise to perceptions of asymmetric regulation, with implications for:

(a) equity considerations;

(b) the commercial value of the Eastern Gas Pipeline;

(c) downstream competition; and

(d) incentives to invest in infrastructure generally.

1.86 The Council considers each application for coverage or revocation on its merits. Where pipelines possess similar characteristics, it is reasonable to expect that consistent application of the coverage criteria would result in the same coverage or revocation outcome in respect of each pipeline. However, where there are significant differences between pipelines, a consistent application of the coverage criteria might result in different coverage outcomes.

1.87 The Council considers that there are fundamental differences between the circumstances of the EGP, and the MSP Mainline and Canberra Lateral. As discussed under criterion (a), the Council has reached a view that EAPL is able to exercise substantial market power in providing the services of the MSP Mainline and the Canberra Lateral. This can be compared with the Tribunal's finding that Duke Energy does not have market power in providing the services of the EGP. These differences suggest there are valid grounds for coverage of the MSP Mainline and Canberra Lateral despite non-coverage of the EGP.

1.88 The Council does not consider it contrary to the public interest to regulate pipelines that are able to exercise substantial market power while not regulating pipelines without market power. This outcome is clearly the intention of the National Gas Code; as evidenced by the inclusion of coverage criteria that use the existence of market power as a major determinant.

1.89 The Council notes that perceptions of asymmetric regulation, as raised by a number of parties, appear to flow from an assumption that the Moomba to Sydney Pipeline System and the EGP compete against one another in a direct sense. As the Council explains in its discussion of criterion (a), competition between the pipelines, to the extent that it occurs, is derived from competition between bundled products of delivered gas. That the pipelines do not compete with one another in a direct sense is apparent from the fact that the tariffs charged by each pipeline for shipping gas to Sydney are substantially different; and the fact that these tariffs have become more divergent since 2000. Thus, it is difficult to sustain the argument that different approaches to regulation might require the EGP to match regulated Moomba to Sydney Pipeline System tariffs.

1.90 Regarding implications for the commercial value of the EGP, the Council notes that the EGP was financed and constructed in an environment in which the Moomba to Sydney Pipeline System was a covered pipeline. In this sense, it is reasonable to assume that parties invested in the EGP with full knowledge and expectation that the provisions of the National Gas Code would apply to the Moomba to Sydney Pipeline System.

1.91 The Council has also taken account of the potential costs of access regulation for investment generally. The Council notes that the principal issues raised in submissions relate to the perceptions of asymmetric regulation in this instance. The Council does not accept these arguments for the reasons outlined above.

1.92 Aside from perceptions of asymmetric regulation, the Council is not aware of any reasons why coverage in this instance raises unique issues of investment risk. The Council notes that the Moomba to Sydney Pipeline System is a mature pipeline that has been covered under the National Gas Code since the Code's inception, and was previously the subject of access legislation set out in the *Moomba to Sydney Pipeline System Sale Act 1994 (Cwlth)*. Thus, issues of investor uncertainty that might reasonably be associated with greenfields pipeline investments do not arise here.

1.93 The Council further notes that in listing the Moomba to Sydney Pipeline System on Schedule A of the Code, Governments regarded the pipeline as having substantial market power, and therefore, as a pipeline that should be regulated. Governments implemented the National Gas Code to provide appropriate regulation of natural gas pipelines with substantial market power.

1.94 Based on the Council's assessment of criterion (a), the Moomba to Sydney Pipeline System continues to enjoy substantial market power that can be exploited in dependent markets. While regulation of any gas pipeline carries attendant costs, the Council has reached a view under criterion (a) that the competition benefits of coverage in this instance are substantial.

Direct costs of regulation

1.95 The Council recognises that there are direct costs associated with regulation under the National Gas Code and that these can be significant. Costs include the pipeline owner's costs of preparing access arrangements and the regulator's costs of assessing compliance with the requirements of the Code. There is also the risk of regulator error, or the perception of it, given that regulated access pricing is a complex and contentious area.

1.96 The Council notes that some of the costs commonly associated with regulation may be incurred in any case; for example, settling terms and conditions of access with third party shippers. It is reasonable to assume that the costs of regulating monopoly infrastructure were taken into account by CoAG in its decision to implement the National Gas Code.

1.97 In addition, the costs of regulation need to be viewed in relation to the likely benefits of regulating access to a particular service. The benefits of regulating access flow from the restraint of monopoly pricing. Access regulation can make upstream and downstream industries more viable, reduce delivered gas prices to consumers and reduce the need for unnecessary investment in alternative facilities.

1.98 For pipelines like the MSP Mainline and the Canberra Lateral, which transport very large amounts of gas annually, even a small reduction in tariffs as a result of regulation is likely to outweigh the costs of regulation.

1.99 The Council estimates that if the regulatory costs over the period 2001-2005 were $2 – 3 million, then the associated benefit in reduced tariffs would only need to be 0.4 – 0.6¢/GJ, to offset the impact of the direct costs of regulation on delivered gas prices (assuming all of the regulatory costs were passed on). In comparison, adjusted indicative tariffs proposed by the ACCC over the period 2001 – 2005 are, on average 16¢/GJ less than EAPL's current tariffs (ACCC 2000b, p.119).[11]

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[11] For the Moomba to Sydney transportation service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005,

1.100 The Council concluded under criterion (a) that the MSP Mainline and Canberra Lateral have substantial market power. In the circumstances, the benefits of coverage for competition are likely to be significant. For large users in particular, the gains from regulation in the form of substantially reduced tariffs could be very significant. Against this, evidence on the direct costs of coverage suggests that these are likely to be relatively small compared to the likely benefits of coverage.

1.101 The Council recognises that consideration of the costs of coverage is very important. Overall, the Council considers that the substantial benefits of coverage in this instance are likely to outweigh the costs.

Information Disclosure

1.102 If the MSP Mainline and Canberra Lateral were covered, then EAPL as the owner of the pipelines would need to comply with the information disclosure provisions of the National Gas Code. The Code requires the owner of a covered pipeline to provide information to users and prospective users on tariff determination methodology, capital costs, operations and maintenance costs, overheads and marketing costs, system capacity and volume assumptions, and key performance indicators (as set out in Attachment A to the Code).

1.103 The Code's information disclosure provisions were designed to provide access seekers with information to aid negotiation of transportation contracts. Users and peak user bodies have argued that the information disclosure provisions of the Code provide significant public benefits.

1.104 In considering coverage of the EGP, the Tribunal preferred the view that the Code's information disclosure requirements might facilitate parallel pricing between the Moomba to Sydney Pipeline System and the EGP.

1.105 In the *Duke EGP decision*, the Tribunal concluded that criterion (a) was not satisfied, meaning there were few or no identified benefits

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adjusted to reflect recent changes in the ACCC's approach to deferred tax liabilities ($0.50/GJ).

This comparison of the dead-weight costs of regulation with the likely reduction in transportation tariffs is used as an indication only of the likely relative magnitude of relevant costs and benefits.

from greater competition to offset possible costs associated with information disclosure.

1.106 The Council notes that the National Gas Code provides the regulator with discretion to allow aggregation of information to protect the legitimate business interests of a pipeline owner. This discretion can be exercised to prevent the flow of commercially sensitive information that could be used to engage in parallel pricing.

1.107 Further, the argument that the Code's disclosure requirements enhances the risk of parallel pricing fails to recognise that coverage constrains prices to cost-based levels. As such, the risk of parallel pricing is significantly reduced.

1.108 The Council considers that the benefits of information disclosure in regard to the MSP Mainline and the Canberra Lateral – notably the promotion of a better-informed market – are likely to outweigh any costs associated with increased potential for parallel behaviour. This is because the benefits of information disclosure identified by users and user groups are significant, and because of the significant likely competition benefits associated with constraining MSP Mainline and Canberra Lateral tariffs.

Conclusion on criterion (d)

1.109 Following consideration of issues raised in public consultation, the Council concludes that access (or increased access) to the services of the MSP Mainline and the Canberra Lateral would not be contrary to the public interest. The Council therefore finds that the MSP Mainline and the Canberra Lateral satisfy criterion (d).

Abbreviations and glossary of terms

ABARE	Australian Bureau of Agricultural and Resource Economics
ACCC	Australian Competition and Consumer Commission
Access Arrangement	Arrangement by owner or operator of a covered Pipeline setting out the terms and conditions and tariffs on which third parties may seek access to the services of the pipeline. Access Arrangements must be approved by the relevant regulator as complying with the requirements of the National Gas Access Code
ACT	Australian Capital Territory
AGL	The Australian Gas Light Company, or an associated company. Does not refer to EAPL or APT
AGA	Australian Gas Association
AGLES&M	AGL Energy Sales and Marketing Limited
AGLGN	AGL Gas Networks Limited
AGLRE	AGL Retail Energy Limited
AGLWG	AGL Wholesale Gas Limited
AGUG	Australian Gas Users' Group
APIA	Australian Pipeline Industry Association
APL	Australian Pipeline Limited
APT	Australian Pipeline Trust, the owner of EAPL
Bass Strait producers	Esso and BHP, the joint venture producers at the Gippsland Basin in the Bass Strait
BCA	Business Council of Australia
Bcf	Billion cubic feet, a measure of a gas reserve resource. 1 PJ equals 1.08 Bcf, and 1 Bcf equals 0.926 PJ
BHP	Broken Hill Proprietary Limited
¢/GJ	cents per GJ
Canberra Lateral	the transmission pipeline branching off the MSP Mainline at Dalton and running to North Watson in Canberra
CoAG	Council of Australian Governments, constituted by the Commonwealth Government and the eight State

	and Territory Governments
Council	National Competition Council
covered pipeline	A pipeline covered under the National Gas Access Code
CSM	coal-seam methane
Duke Energy	Collective reference to Duke Eastern Gas Pipeline Pty Ltd, DEI Eastern Gas Pipeline Pty Ltd, and Duke Australia Operations Pty Ltd as the joint owners of the Eastern Gas Pipeline, or any one of these three companies
EAPL	East Australian Pipeline Limited, the owner of the Moomba to Sydney Pipeline System
EMRF	Energy Markets Reform Forum
EUAA	Energy Users Association of Australia
FERC	Federal Energy Regulatory Commission, the US regulatory agency charged with regulation of infrastructure including natural gas pipelines
Gas Access Acts	The Acts in each State and Territory which provide for third party access to the services of natural gas pipelines. The Acts apply the GPAL and National Gas Access Code as law in those jurisdictions
GGT	Goldfields Gas Transmission Pty Ltd
GJ	Gigajoule, a unit of measurement for measuring the energy content of natural gas or other energy sources
GPAL	Gas Pipelines Access Law, which in conjunction with the National Gas Access Code and the Gas Access Acts, sets out provisions of the regime for third party access to the services of gas pipelines
GST	Goods and services tax
GTA	Gas transportation agreement
GTD	Gas Transportation Deed
Interconnect	The pipeline between Wagga Wagga and Albury/Wodonga connecting the NSW and Victorian gas networks. The portion between Wagga Wagga and Culcairn in NSW is owned by EAPL, and the portion running from Culcairn to Barnawartha in Victoria (which crosses the border) is owned by GPU GasNet

ICRC	Independent Competition and Regulatory Commission, which regulates the ACT, Queanbeyan, and Yarrowlumla Shire gas distribution system
IPA	Institute of Public Affairs
IPART	Independent Pricing and Regulatory Tribunal, which regulates most gas distribution systems in NSW
LECG	Law and Economics Consulting Group
MAPS	Moomba to Adelaide Pipeline System
MSP[12]	MSP Mainline and Canberra Lateral of the Moomba to Sydney Pipeline System
MSP Mainline	the main pipeline of the Moomba to Sydney Pipeline System. The MSP Mainline runs from Moomba to Wilton (on the outskirts of Sydney)
MW	Megawatts, a unit of electricity output
National Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
NCC	National Competition Council
NECG	Network Economics Consulting Group
NERA	National Economic Research Associates
Part IIIA	Part IIIA of the Trade Practices Act, which deals with access to the services of essential facilities
PDA	Pipeline Development Agreement
PIAC	Public Interest Advocacy Centre
PIRSA	Department of Primary Industries and Resources, South Australia
PJ	Petajoule (equal to 1,000,000 GJ or 1,000 TJ)
PJ/a	Petajoules per year
PL	Pipeline licence
PMA	Pipeline Management Agreement

12 For the sake of brevity, the abbreviation 'MSP' is used in parts of this report to jointly refer to the MSP Mainline and Canberra Lateral. It should be noted that the MSP Mainline and Canberra Lateral form only part of the Moomba to Sydney Pipeline System. The system also encompasses other laterals that are not subject to the current applications.

PNG	Papua New Guinea
SACBUP	South Australian Cooper Basin Unit Producers, based at the Moomba gas fields in the Cooper Basin, and led by Santos
SSNIP	small but significant non-transitory price increase
SWQ producers	South west Queensland gas producers, based at Ballera in Queensland, and led by Santos
Tcf	Trillion cubic feet, a measure of a gas reserve resource. 1,000 PJ equals 1.08 Tcf and 1 Tcf equals 926 PJ
TJ	Terajoule (equal to 1,000 GJ)
TJ/d	Terajoules per day
TPA	Trade Practices Act
(the) Tribunal	Australian Competition Tribunal
Undertaking	A form of voluntary regulation providing for access to a service. Undertakings are provided for under Part IIIA of the Trade Practices Act and must be approved by the ACCC
Vencorp	Victorian Energy Networks Corporation, which operates the Victorian Principal Transmission system including the Longford to Melbourne pipeline

2 The Council's recommendations

Background

2.1 The National Competition Council received applications in June 2001 to revoke two pipelines within the Moomba to Sydney Pipeline System from coverage under the National Third Party Access Code for Natural Gas Pipeline Systems (**National Gas Code**). The applications were made by East Australian Pipeline Limited (**EAPL**), the owner of the pipelines.[13]

2.2 The Moomba to Sydney Pipeline System transports natural gas from Moomba (in South Australia) to Wilton (just outside Sydney) and via transmission laterals to regional New South Wales (**NSW**) and the Australian Capital Territory (**ACT**). The system joins with the Victorian gas transmission system near Wagga Wagga, enabling the transportation of gas in either direction between NSW and Victoria.

2.3 EAPL seeks revocation from coverage of two pipelines within the Moomba to Sydney Pipeline System:

(a) the main pipeline running from Moomba to Wilton, comprising three separate pipeline licences: SA:PL7 (Moomba to Queensland border), Qld PPL21 (South Australia border to NSW border), and NSW:16 (Queensland/NSW border to Wilton). This pipeline is hereafter described as the **MSP Mainline**; and

(b) the transmission lateral branching off the MSP Mainline at Dalton and running to North Watson in Canberra (pipeline licence NSW:21). This pipeline, hereafter described as the **Canberra Lateral**, transports gas to the distribution system supplying ACT, Queanbeyan, and the Yarrowlumla shire.

2.4 The National Gas Code establishes a framework for parties to negotiate access to gas pipeline services. Coverage mechanisms have been established to determine whether a particular pipeline is subject to the National Gas Code's obligations. The Moomba to

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13 EAPL is wholly owned by the Australian Pipeline Trust.

Sydney Pipeline System has been a covered pipeline since the Code's commencement.[14]

2.5 Section 1 of the National Gas Code establishes a mechanism for parties to seek revocation of coverage of a pipeline from the Code's provisions. The EAPL applications were made under these provisions.

2.6 In considering the applications, the Council has applied the criteria set out in s.1.9 of the National Gas Code. To assist its consideration, the Council sought the views of stakeholders in 2001 and received fourteen submissions, available on the Council's web site at www.ncc.gov.au. In addition, the Council's secretariat met with interested parties including: the Australian Competition and Consumer Commission (**ACCC**), Country Energy, Duke Energy, EAPL/Australian Pipeline Trust (**APT**), the Energy Markets Reform Forum, the Energy Users Association of Australia, GasAdvice, the Independent Competition and Regulatory Commission (the ACT gas distribution system regulator), the ACT Department of Urban Services, Incitec, the Independent Pricing and Regulatory Tribunal of NSW (**IPART**, the NSW gas distribution system regulator), and Origin Energy.

2.7 The Council also considered work undertaken by Professor Janusz Ordover (New York University) and Dr William Lehr (Massachusetts Institute of Technology) on questions raised by criteria (a) and (b) of s.1.9 of the National Gas Code. This work, attached in full at Attachment 5 of this recommendation, was commissioned by the Council to provide advice on two questions:

(a) First, given that the Moomba to Sydney Pipeline System is presently a natural monopoly in the provision of transportation services between Moomba and Sydney, what are the relevant economic criteria that should be used to determine whether that pipeline possesses market power in the provision of transmission services, and if it does, whether the pipeline has both the incentive and ability to exercise that power in the downstream market for gas sales?

[14] The Moomba to Sydney Pipeline System is listed at Schedule A of the Code. Pipelines listed at Schedule A are automatically covered from the commencement of the Code.

(b) Second, based on the economic framework described above and a review of circumstances pertaining to the relevant markets in Australia, does the Moomba to Sydney Pipeline System possess substantial market power in the retail markets for gas sales in NSW/ACT?

2.8 The Council's draft recommendations, released in December 2001, drew on public submissions, meetings with stakeholders, the findings of the Australian Competition Tribunal in related matters (see paragraph 5.8 of this report), the work of Ordover and Lehr, and the Council's consideration of the issues raised. In the report, the Council stated its preliminary view that coverage of the MSP Mainline and Canberra Lateral should not be revoked.

2.9 The draft recommendations sought further comment from stakeholders. Eight submissions were received in February 2002. This was followed by three further submissions made in response to the issues raised in the February submissions.

2.10 The submissions on the Council's draft recommendations raised a number of substantial issues. In particular, the Council sought legal advice on vertical linkages between EAPL and other businesses in the gas supply chain. In addition, the Council sought advice from the ACCC on a number of technical issues raised in a joint submission from EAPL and Network Economics Consulting Group (**NECG**). The ACCC subsequently engaged National Economic Research Associates (**NERA**) to critique some aspects of the submission. NERA completed its report in September 2002. The Council released the ACCC advice and NERA report for comment, and received further submissions.

Recommendations

2.11 Following consideration of all submissions and other consultation with stakeholders, the work of Ordover and Lehr, technical advice from the ACCC, the NERA report (and submissions on the advice and report), and legal advice on vertical linkage issues, the Council is satisfied that the whole of the MSP Mainline and Canberra Lateral satisfy all of the criteria in s.1.9 of the National Gas Code. The Council therefore recommends that coverage of the MSP Mainline and Canberra Lateral under the National Gas Code should not be revoked.

2.12 The Council's assessment of the MSP Mainline and Canberra Lateral against the revocation criteria is set out in sections 5 to 9 of this report.

2.13 Sections 3 and 4 of the report provide background information relevant to the EAPL applications:

(a) Section 3 provides details of the EAPL applications, explains the revocation process, and notes recent regulatory developments relevant to the MSP Mainline and Canberra Lateral.

(b) Section 4 provides background on the structure of the natural gas industry in Australia, with a particular focus on NSW and the ACT.

3 The applications

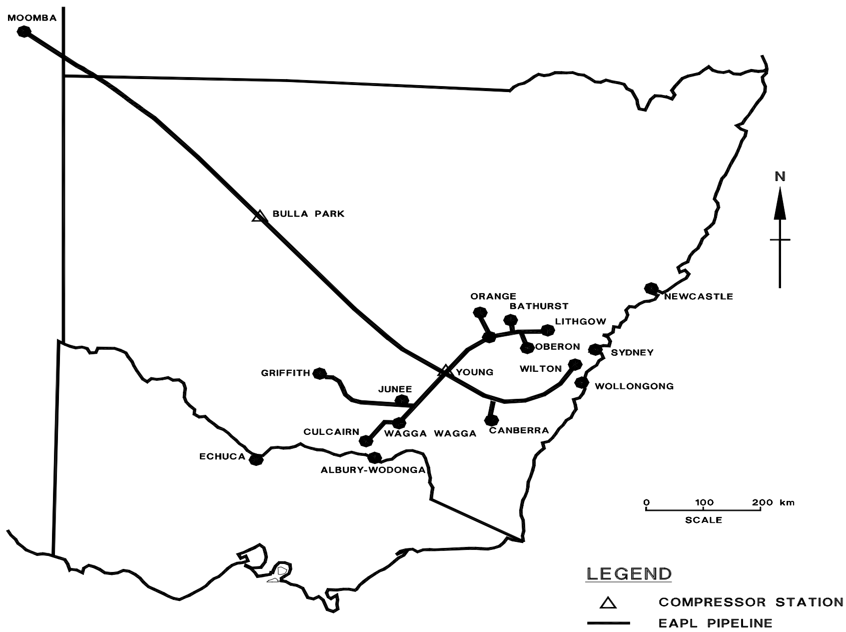
The application pipelines

3.1 On 18 June 2001, the Council received applications to revoke two pipelines within the Moomba to Sydney Pipeline System from coverage under the National Gas Code. The applications were made by East Australian Pipeline Limited (**EAPL**) as the owner of the system.

3.2 The Moomba to Sydney Pipeline System transports natural gas from Moomba (in South Australia) to Wilton (near Sydney), and via laterals to regional NSW (**NSW**) and the ACT. The system interconnects with the Victorian gas transmission system near Wagga Wagga, enabling gas to be transported in either direction between NSW and Victoria.

3.3 The route of the Moomba to Sydney Pipeline System is illustrated in Figure 1.

Figure 1: Moomba to Sydney Pipeline System



Source: EAPL application for revocation, p. 4.

3.4 Table 1 provides details of the pipelines within the Moomba to Sydney Pipeline System for which revocation of coverage is sought. The Council considers that the pipelines constitute two major pipelines, each providing separate services. It has therefore accepted EAPL's application on the understanding that it constitutes an application for revocation of coverage of two separate pipelines: the main pipeline running from Moomba to Sydney (**the MSP Mainline**); and the transmission pipeline branching off it to Canberra (**the Canberra Lateral**).

Table 1: The MSP Mainline and Canberra Lateral

Pipeline Licence	*Location/Route*	*Length (km)*	*Diameter (mm)*
MSP Mainline			
SA:PL7	Moomba to Queensland border	111 (including 10 km loop at Moomba)	864 660
Qld:PPL21	South Australia border to NSW border	56.2	864
NSW:16	Queensland/NSW border to Wilton	1,142	864
Canberra Lateral			
NSW:21	Dalton to ACT border	52	273
	ACT/NSW border to North Watson	6	273

3.5 The Council has made separate assessments of whether the MSP Mainline and the Canberra Lateral respectively satisfy the coverage criteria. However, given the common ownership of the pipelines and the overlapping coverage issues raised, the Council has conducted some of its processes for the applications on a joint basis. In particular, the Council ran joint public consultation processes and presents its recommendations in a single report.

3.6 EAPL has not sought revocation of coverage of other pipelines in the Moomba to Sydney Pipeline System such as the Young to Lithgow Lateral (and associated spurs) or the Junee to Griffith Lateral.

3.7 The primary source of natural gas for the Moomba to Sydney Pipeline System is gas collected in the Cooper Basin, which is processed at the Moomba processing plant. Gas from the Cooper Basin is jointly produced and marketed by the South Australian Cooper Basin Unit Producers (**SACBUP**), in which Santos has a majority interest. The Moomba to Sydney Pipeline System can also carry gas from the Gippsland Basin in Victoria via the Interconnect pipeline (**Interconnect**), which links the NSW and Victorian gas transmission systems.

3.8 In the longer term, the Moomba to Sydney Pipeline System may carry gas from north west Australia or Papua New Guinea, via the proposed Darwin to Moomba pipeline and/or Papua New Guinea to Moomba pipeline.

3.9 The Moomba to Sydney Pipeline System was expected to transport **[confidential information]**of gas in 2002. This represents **[confidential information]** of total gas deliveries into NSW in that year.[15] The system currently has available capacity of 172 PJ per annum, and has the potential to be expanded to carry at least 292 PJ per annum through the addition of six compressors along its length (EAPL 2001, sub.13, p.2).

3.10 The Council understands that a significant proportion of the capacity of the Moomba to Sydney Pipeline System is committed under the Gas Transportation Deed between EAPL and AGL Wholesale Gas Limited (**AGLWG**). Under this deed EAPL transports gas from Moomba to Wilton, facilitating AGLGN's 30 year take-or-pay arrangement with the SACBUP. AGL companies then distribute the gas, mainly through the AGL Gas Networks (**AGLGN**) distribution network in Sydney and surrounding regions. Some of the gas transported by the Moomba to Sydney Pipeline System is supplied to users in regional centres via laterals running off the MSP Mainline.

3.11 Further information on the Moomba to Sydney Pipeline System is provided at paragraphs 4.46 to 4.54 of this report.

Legislative framework

3.12 The EAPL applications were made under the National Gas Code, which is given effect by the Gas Access Acts of NSW, South Australia, Queensland, and the ACT. The relevant legislation is in the *Gas Pipelines Access (NSW) Act 1998*, the *Gas Pipelines Access (SA) Act 1997*, the *Gas Pipelines Access (Queensland) Act 2000* and the *Gas Pipelines Access (ACT) Act 1998*. Additionally, the *Gas Pipelines Access (Commonwealth) Act 1998* enables certain actions to be taken in support of the NSW, South Australian, Queensland and ACT Gas Access Acts.

[15] Derived from the following information: **[confidential information]** (EAPL 2002, p.4).

3.13 The Gas Access Acts of NSW, South Australian, Queensland, and ACT enact the Gas Pipelines Access Law (**GPAL**), which in turn, applies the National Gas Code.

3.14 The National Gas Code establishes a framework for parties to negotiate access to gas pipeline services within an independent regulatory framework. Coverage mechanisms have been established to determine whether a particular pipeline is subject to the Code's obligations. The Moomba to Sydney Pipeline System has been a covered pipeline since the commencement of the Code.[16]

3.15 The National Gas Code recognises that the public benefits of regulating access to a service may change over time due to such factors as changes in market conditions (for example, the emergence of effective competition) or technological changes affecting the economic viability of new infrastructure. The Code therefore allows parties to seek revocation of coverage of a pipeline. The processes for dealing with revocation applications are specified in ss.1.24 to 1.39 of the National Gas Code.

3.16 Revocation applications are made to the Council. Following consideration of issues raised in public consultations, the Council conveys a recommendation to the relevant Minister, who decides the matter. Both the Council and the Minister must apply the criteria for revocation set out in ss.1.9 and 1.31 of the National Gas Code. If revocation is granted, the owner/operator of a pipeline is released from obligations under the National Gas Code. In particular, the owner/operator is not required to submit an access arrangement for the pipeline to the relevant regulator, or to respond to access requests by third parties.[17]

The Minister's process

3.17 The Minister responsible for deciding the EAPL applications is the Commonwealth Minister for Industry, Tourism and Resources.[18]

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16 The Moomba to Sydney Pipeline System is listed at Schedule A of the Code. Pipelines listed at Schedule A are automatically covered from the commencement of the Code.

17 Of course, the owner/operator of a non-covered pipeline may provide access on a voluntary basis.

18 See the definition of 'Relevant Minister' in the National Gas Code and the GPAL, and Annex G to the *Natural Gas Pipelines Access Agreement* between CoAG Ministers in November 1997. The MSP Mainline and Canberra Lateral are classified as transmission pipelines. By reason of this, and the fact that the

Upon receipt of the Council's recommendations, the Minister has 21 days to decide whether or not to grant revocation of coverage of one or both of the pipelines. The Minister may extend this period by advertising his intention to do so prior to the expiry of the 21 day period.

3.18 The Minister must provide copies of his decision and reasons to relevant parties, including the owner/operator and any party who made a submission. The Minister's decision (if it is to grant revocation of coverage) can take effect no earlier than 14 days after the date on which it is made.

3.19 Under clause 38 of the GPAL, any person adversely affected by the Minister's decision may apply to the Australian Competition Tribunal for a review of the Minister's decision.[19]

Other regulatory processes affecting the pipelines

3.20 At present, the whole of the Moomba to Sydney Pipeline System, including the MSP Mainline and Canberra Lateral are covered pipelines under the National Gas Code. The Code requires the pipeline owner to submit an access arrangement to the regulator, setting out proposed terms and conditions of access. The regulator with respect to the Moomba to Sydney Pipeline System is the ACCC.

3.21 Under the Code, the regulator may accept the service provider's proposed access arrangement, or may require amendments.

3.22 The access arrangements must set out, at a minimum:

(a) a services policy (describing the services to be offered);

(b) reference tariffs for one or more of these services;

(c) terms and conditions on which services will be provided;

(d) a capacity management policy;

primary pipeline within the Moomba to Sydney Pipeline System is an interstate pipeline, the responsible Minister for deciding these applications is the Commonwealth Minister for Industry, Tourism and Resources.

19 See definition of 'Relevant Appeals Body' in the National Gas Code and the GPAL.

(e) a trading policy under which third parties with contracted capacity may trade that capacity;

(f) a queuing policy, to determine priority for access seekers;

(g) an extensions/expansions policy, for determining whether an extension or expansion of the pipeline will be treated as part of the pipeline for the purposes of the Code; and

(h) a review date, specifying the date by which the access arrangement must be revised.

3.23 EAPL, the owner of the MSP Mainline and the Canberra Lateral submitted a proposed access arrangement to the ACCC in May 1999 (and provided further information in October 1999). The ACCC released a draft decision on the access arrangement in December 2000, proposing a number of amendments. The main variations between EAPL's proposed access arrangement and the ACCC's draft decision are:

(a) The ACCC proposed an average indicative tariff of $0.47/GJ over the period 2001-05 to transport gas from Moomba to Sydney (ACCC 2000b, p.119). This was derived from the ACCC's view on the appropriate initial capital base, appropriate rate of return, depreciation, forecast revenues, and forecast volumes. The ACCC has subsequently indicated that regulatory approaches to the treatment of deferred tax have evolved since the 2000 draft decision, and that it may be appropriate to add back deferred tax liabilities for the purpose of tariff determination. The ACCC estimates that this would add about $0.03/GJ to reference tariffs (ACCC 2002b, p.5). This would result in an average indicative 2001-2005 Moomba to Sydney tariff of $0.50/GJ, as compared with EAPL's current tariff of $0.66/GJ.[20] The current EAPL tariff is about 32% higher than the ACCC indicative tariff.

(b) The ACCC adjusted indicative tariff to transport gas from Moomba to Canberra over the period 2001-05 averages about $0.46/GJ.[21] This compares with EAPL's current tariff

[20] Tariffs quoted in this section exclude GST.

[21] Adjusted for revised treatment of deferred tax liabilities. See paragraph 3.23(a).

of $0.60/GJ. The current EAPL tariff is about 30% higher than the adjusted ACCC indicative tariff.

(c) The ACCC has proposed some clarifications to the standard form terms and conditions on which services are provided (ACCC 2000b, pp. xvi – xviii).

(d) The ACCC has proposed some relaxation of the conditions forming part of the trading and queuing policies (ACCC 2000b, pp. xviii – xix).

(e) The ACCC has proposed amendments to the extensions and expansions policy with regard to EAPL's discretion to decide which extensions and expansions should be included in the access arrangement (ACCC 2000b, p. xix).

Previous applications

3.24 EAPL previously applied for revocation of coverage of the MSP Mainline, the Canberra Lateral, and the Young to Culcairn Lateral (inclusive of the Cootamundra spur) in April 2000. In September 2000, the Council recommended to the Minister that revocation of coverage of these pipelines not be granted. The Minister subsequently decided not to revoke coverage of the pipelines. EAPL did not apply for a review of the Minister's decision.

3.25 In January 2000, AGL Energy Sales and Marketing Limited (**AGLES&M**) applied for coverage of the Eastern Gas Pipeline (**EGP**), which is owned by the Duke Energy group of companies. The EGP was then being constructed to bring gas from the Gippsland Basin in Victoria to Sydney, Canberra, and some regional NSW towns. In June 2000, the Council recommended coverage of the EGP, and the Minister subsequently decided to cover the pipeline. Duke Energy applied for a review of the Minister's decision by the Australian Competition Tribunal. The Tribunal heard the application for review in January and February 2001. On 4 May 2001, the Tribunal decided that the EGP did not meet criterion (a) of the criteria for coverage, and that consequently the pipeline should not be covered under the National Gas Code.

3.26 In its current applications to revoke coverage of the MSP Mainline and Canberra Lateral, EAPL refers to the Tribunal's *Duke EGP* *decision*[22] to support its view that the pipelines do not meet all of the coverage criteria.

[22] *Duke Eastern Gas Pipelines Pty Ltd* (2001) ATPR 41-821.

4 Background

Overview

4.1 Natural gas is an important source of energy in Australia. The share of total primary fuel consumption attributable to natural gas rose nationally from 8.8% in 1976-77 to 18.1% in 1998-99 and further growth is forecast (AGA 2001, pp.3, 53).

4.2 Natural gas occurs in raw form in natural reservoirs located both on land and at sea. Upstream *production* relates to the collection of natural gas via gathering pipelines and processing to remove impurities. The gas is then transported by large capacity, high-pressure *transmission pipelines* to user destinations, where it is supplied directly to very large industrial users or via medium and low-pressure *distribution pipelines* to smaller industrial, commercial, and residential users. In the course of supply to smaller industrial, commercial and residential users, *retailers* provide marketing, billing, and meter reading services.

4.3 The natural gas supply chain therefore comprises:

(a) exploration for and production of natural gas;

(b) transportation of natural gas through transmission and distribution pipelines; and

(c) gas sales by gas producers, wholesalers, distributors, retailers and other parties, to gas users.

4.4 A map of Australia's major gas basins and transmission pipelines is provided at Figure 2.

Gas reform

4.5 Until recently, natural gas supplies to NSW and the ACT were sourced from a single basin via the Moomba to Sydney Pipeline System. Similar arrangements were a feature of the natural gas industry in other States and Territories. Many State governments were reluctant to permit gas discovered within their jurisdictions to be sold to interstate parties, and erected legislative barriers to trade.

4.6 Between 1992 and 1997, the Commonwealth and the States and Territories (as the Council of Australian Governments, **CoAG**) struck a series of agreements designed to create a national gas market characterised by more competitive supply arrangements. CoAG agreed to:

(a) remove legislative and regulatory barrier to interstate and intrastate trade in gas;

(b) introduce third-party access rights to interstate and intrastate gas pipelines;

(c) introduce uniform national pipeline construction standards;

(d) commercialise the operations of publicly-owned gas utilities;

(e) remove restrictions on the uses of natural gas (eg. for electricity generation); and

(f) ensure gas franchise arrangements were consistent with free and fair competition in gas markets and third party access.

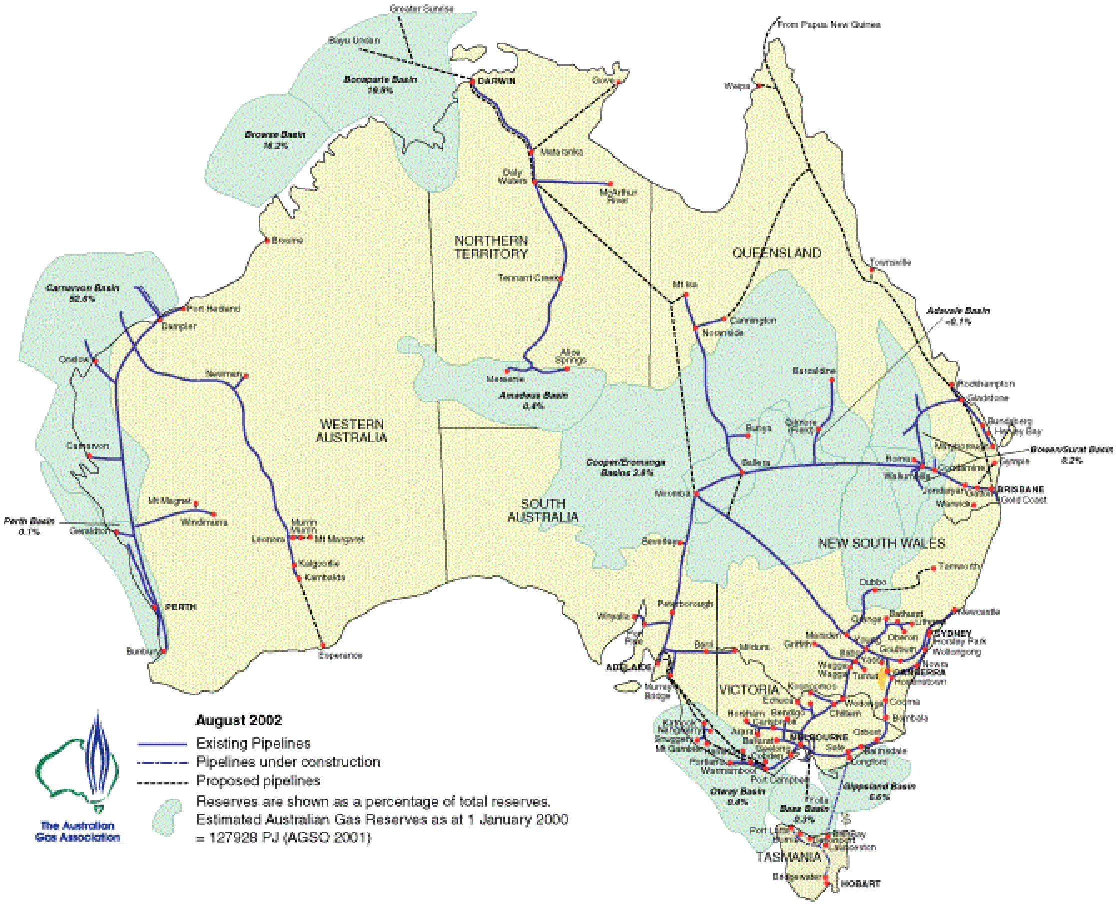
4.7 The reforms were expected to lead to the disaggregation of gas and gas transportation contracts for larger users, entry in the retail sector by new retailers and aggregators, and the wider use of services such as interruptible services.

4.8 An important outcome of the gas reform process was the *Natural Gas Pipelines Access Agreement*, signed in 1997 by the Commonwealth, State and Territory Governments. Each jurisdiction gave an undertaking in the Agreement to enact uniform gas access legislation incorporating the National Third Party Access Code for Natural Gas Pipeline Systems (**National Gas Code**).[23] Each jurisdiction has subsequently enacted a Gas Access Act that gives effect to the Gas Pipelines Access Law (**GPAL**) and the National Gas Code.

4.9 Background information on the National Gas Code is provided at paragraphs 3.12 to 3.16 and 3.20 to 3.22 of this report.

23 Tasmania's obligation was postponed to the development of a natural gas industry in that State.

Figure 2: Natural gas basins and pipelines in Australia (reproduced by permission of Australian Gas Association



Production

4.10 Natural gas supplied to NSW, the ACT, Victoria, South Australia and Queensland is principally sourced from the Cooper/Eromanga Basin and from the Gippsland Basin.

4.11 The Cooper/Eromanga Basin is spread across the north-east corner of South Australia and the south-west corner of Queensland. In the year ending June 2000, the Cooper/Eromanga Basin produced 232.4 PJ of natural gas (AGA 2001,p.59), principally for sale in NSW, the ACT, South Australia and Queensland.

4.12 The principal gas fields in the Cooper/Eromanga Basin are located near Moomba, in South Australia (the Cooper Basin) and near Ballera, in Queensland (the Eromanga Basin).

Cooper Basin

4.13 Gas from the Cooper Basin, located in South Australia, is processed at the Moomba processing plant, and is the major source of supply for NSW and the ACT. Cooper Basin gas also supplies a significant share of South Australian gas demand, and can be supplied to Victoria via the Moomba to Sydney Pipeline System and the Interconnect pipeline.

4.14 Gas collected in the Cooper Basin is jointly produced and sold by the South Australian Cooper Basin Unit Producers (**SACBUP**).[24] Santos holds an interest of about 60% in the gas produced by the SACBUP. Esso, through its subsidiary Delhi Petroleum, holds a 20% interest, while Origin Energy holds a 13% interest (PIRSA 2001a).

Eromanga Basin

4.15 Gas collected in the Eromanga Basin, near Ballera in south west Queensland, is produced and sold by the South West Queensland (**SWQ**) producers. Santos holds a 60% interest in the joint venture. The other major participants are Esso and Origin Energy.

4.16 Most of the gas extracted from the Eromanga Basin is processed at Ballera and then shipped to south-east Queensland markets via a network of transmission pipelines. Brisbane is served by the Ballera

24 Joint production means that gas is produced at a shared facility, while joint marketing means that the producers combine together as a single marketing entity to sell to purchasers of gas.

to Wallumbilla pipeline, which interconnects with the Wallumbilla (Roma) to Brisbane pipeline. Other major transmission pipelines are the Wallumbilla to Rockhampton pipeline and the Ballera to Mt Isa pipeline.

4.17 Some raw gas from Ballera is transported to Moomba through a pipeline owned by the SWQ producers, where it is processed for supply to NSW, ACT and South Australia (AGA 2001, p.33; APT 2001b).[25]

Gippsland Basin

4.18 The Gippsland Basin is located in Bass Strait, south east of Melbourne. Gippsland Basin gas is processed at Longford and supplies Melbourne and regional Victoria. In the year ending 30 June 2000, the Gippsland Basin produced 202.2 PJ of natural gas (AGA 2001, p.59). The basin currently supplies almost all the gas used in the principal transmission system in Victoria.[26] Other sources of Victorian supply are gas fields in the Otway Basin (see paragraph 4.30), storage facilities located at Iona to the west of Melbourne, LNG injection facilities at Dandenong, and gas from the Cooper Basin supplied through the Interconnect (Vencorp 2000, pp.16-18). The Gippsland Basin also supplies gas to NSW through the EGP, commissioned in August 2000, and to the ACT via a lateral opened in July 2002. The basin can also supply gas to NSW via the Interconnect.

4.19 The gas fields in the Gippsland Basin currently under production are jointly owned and operated by Esso and BHP. Gas from these fields is processed at Esso's processing plant at Longford near Sale. Esso and BHP jointly sell gas produced in the Gippsland Basin. The producers have take-or-pay agreements to supply a minimum of 80% of Victorian retailers' annual nominated quantities of 180 PJ/a (144 PJ/a). The retailers have the right to take up to 130% (234 PJ/a) of this quantity (Victorian Auditor-General 1997, p.250). The gas supplied under this agreement is capable of meeting most of Victoria's gas requirements until 2009, but leaves some scope for

[25] See paragraph 4.65 of this report.

[26] Historically, about 98% of Victoria's natural gas requirements have been supplied by the Gippsland Basin, with the remaining 2% being supplied by the Otway Basin: Victorian Government, 1999, p.3.

outstanding demand to be met by other supply contracts (Victorian Department of Treasury and Finance 1998, p.62).

Gas reserves

4.20 Recoverable reserves in the Cooper/Eromanga Basin, as at January 2000, were estimated at 4,898 PJ – about 3.8% of Australia's total natural gas reserves. Cooper/Eromanga Basin production in 1999-00 was 232.4 PJ. At this rate reserves could continue to meet current rates of demand for 21 years (AGA 2001, p.59).

4.21 The Tribunal found in the *Duke EGP decision* that Cooper Basin gas reserves, supplemented by gas shipped from basins to the north of Australia, will be sufficient to meet projected gas demand in south-east Australia in the next 10 to 15 years *(Duke EGP decision 2001*, paragraph 103*)*.

4.22 Reserves in the Gippsland Basin are estimated at about 8,390 PJ; about 6.6% of Australia's total gas reserves. At present rates of production (202.2 PJ in 1999-00), Gippsland Basin reserves can meet current rates of demand for 41 years (AGA 2001, p.59).

4.23 As discussed below, significant new exploration expenditure has been committed in the Cooper and Gippsland basins, and other basins such as the Otway Basin.

Exploration and potential developments

Cooper Basin

4.24 Considerable new exploration is being conducted in the Cooper Basin. In 1999-2000, the South Australian Government tendered exploration rights for 27 blocks, with six more blocks tendered in September 2001. The South Australian Minister for Minerals and Energy announced in October 2000 that more than $240 million had been pledged in the period February 1999 to October 2000 to explore for new gas reserves in the Cooper Basin, with this expenditure to occur over the next five years (SA Minister for Minerals and Energy 2000). Much of this expenditure is being committed by exploration companies not previously operating in the basin, including Stuart Petroleum, Beach Petroleum, Magellan Exploration, and Australian Crude Oil (which have collectively been awarded 12 of the 27 blocks). These new entrants are independent of the existing producers in the Cooper Basin, the SACBUP and SWQ Producers (PIRSA 2001b).

4.25 In 2002, oil discoveries were made at Acrasia-1, Acrasia-2 and Sellecks-1 by new entrants in the Cooper Basin, with production from some wells expected to follow soon. The new discoveries are located within an 85 km radius of the Moomba production facility. Further exploration work is continuing elsewhere in the Basin (Beach Petroleum 2002b, 2002c, 2002d).

4.26 The Council understands from discussions with Primary Industries and Resources SA that the new entrants have focussed their exploration work to date on petroleum, but that gas discoveries are likely as a by-product of this exploration work. Primary Industries and Resources SA has indicated to the Council that gas discoveries could take 3-5 years, but could be much sooner.

Gippsland Basin

4.27 The Gippsland Basin has a number of undeveloped fields, including the Patricia-Baleen, Kipper, Basker, Sole, Manta, Gummy, and Golden Beach fields. Producers independent of BHP and Esso, such as Woodside and Santos, hold interests in these fields.

4.28 Two production wells were successfully drilled in the Patricia-Baleen gas fields in 2002. Offshore pipe laying was completed in July 2002, and the onshore pipeline from the gas plant to the EGP is complete. Energex has contracted with the field owners to take 60 TJ/day from the field (DNRE 2002), and will build a new gas processing plant near Orbost. The gas will be delivered into the EGP and could be transported to NSW, or alternatively to Victorian users through backhaul or swap arrangements. The facility at Orbost may produce around 12 PJ/a.

4.29 Woodside is examining development of the Kipper field, which contains around 460 PJ. The Kipper field is owned by Esso (50%), Woodside (30%), and Santos (20%) (Woodside 2001b). Woodside also holds a 100% interest in the Basker, Manta, and Gummy fields, which have potential reserves of around 240 PJ (Woodside 2001b).

Otway Basin

4.30 Major new discoveries have been made in the Otway Basin since 2000. The basin covers a large onshore and offshore area of western Victoria and south eastern South Australia, and includes the offshore Thylacine, Geographe, Minerva, and La Bella gas fields as well as some onshore fields. Commercial reserves of gas exist in the Minerva and La Bella fields, in which BHP and Santos hold interests.

4.31 BHP Petroleum has signed terms to supply about 270 PJ over 10 years from the Minerva field to supply International Power's electricity generation facility at Pelican Point in South Australia. The agreement underpins construction of the proposed SEA Gas Pipeline from the Otway Basin to Adelaide (see paragraph 4.68).

4.32 Santos has been supplying gas from onshore fields in the Otway Basin to Victorian users since 1999, (Santos 2001) and has recently discovered more gas in onshore fields (DNRE 2002). Recent discoveries suggest the Thylacine field could hold up to 926 PJ and the Geographe field could hold up to 556 PJ although these amounts are not proven (Woodside 2001a, p.9). Woodside Energy signed a Heads of Agreement in August 2002 with TXU Electricity for the sale of gas from the Thylacine and Geographe fields, with gas deliveries expected from 2006 (AGA 2002, p.2).

Bass Basin

4.33 The Bass Basin lies south of the Otway Basin to the south west of Melbourne. The major fields in the basin are the Yolla and White Ibis gas fields. The Yolla field is estimated to hold more than 305 PJ of gas and White Ibis 50 PJ. Origin, AWE Petroleum, Galveston Mining Corporation Pty Ltd, and CalEnergy Gas (UK) jointly own these fields. Origin, AWE Petroleum, and CalEnergy have signed separate gas sales agreements to supply gas from these fields equivalent to about 10% of Victoria's current gas consumption (Australian Gas Journal 2001, p.46).

Northern Australia

4.34 Two major gas projects to the north of Australia are proposed to supply gas to south east Australia over the medium term:

(a) the Timor Sea project; and

(b) the Papua New Guinea project.

4.35 The Timor Sea reserves include the Bayu-Undan and Greater Sunrise gas fields, which lie partly in a joint Australian/East Timorese zone of control. The Bayu-Undan field is owned by a joint venture led by Phillips, and contains estimated reserves of around 3,148 PJ (Phillips 2001, Bayu-Undan 2001). The Greater Sunrise fields, comprising the Sunrise and Troubadour gas fields, are owned by Woodside Petroleum (33.44%), Phillips Petroleum (30%), Shell (26.56%), and Osaka Gas of Japan (10%) (Woodside 2001d). The

Greater Sunrise fields contain natural gas reserves of more than 8,444 PJ (Woodside 2001d).

4.36 Gas could be supplied from the fields via an undersea pipeline to Darwin for processing and then supplied to Moomba either through a major pipeline from Darwin to Moomba (as proposed by Epic Energy) or through interconnections with the Darwin to Alice Springs pipeline or the Mt Isa to Ballera pipeline (as proposed by APT). APT stated in its May 2000 prospectus that the Moomba to Sydney Pipeline System was ideally placed to transport Timor Sea gas to NSW, thus securing a long term future for the Moomba to Sydney Pipeline System as gas reserves in the Cooper Basin are depleted (EAPL 2000a, p.22 and appendices, pp.12 - 13).

4.37 The Tribunal found in the May 2001 *Duke EGP decision* that "supplies of gas through Moomba are likely to be sufficient over the next 10 to 15 years as gas from the Cooper/Eromanga Basin will be supplemented by gas from basins to the north of Australia" (*Duke EGP decision*, paragraph 103). It would take a number of years to build the production, processing, and pipeline infrastructure before gas could be carried in the Moomba to Sydney Pipeline System.

4.38 In May 2002, Phillips and its co-venturers signed a Treaty and Memorandum of Understanding with the East Timorese Government, providing greater certainty on the viability of the project. As part of the agreement, a number of legal, fiscal and taxation issues have been resolved (ITR 2002).

4.39 The Papua New Guinea (**PNG**) project would ship gas from Kutubu in Papua New Guinea to major centres in Queensland including Townsville, Gladstone, and Brisbane. The scope of the project has recently been expanded to incorporate links to Mt Isa and Moomba. If this eventuates, the pipeline could eventually interconnect with the Moomba to Sydney Pipeline System.

4.40 The project is being sponsored by ExxonMobil, and a consortium of AGL and Petronas has been selected to build the 3,200 km pipeline (Orogen 2001; PNG gas project office 2001). Proven and probable reserves amount to 4,630 PJ in the Kutubu and adjoining fields, with substantial potential for additional gas reserves (Orogen 2001).

4.41 The proponents signed a Memorandum of Understanding with the PNG Government in February 2002, providing a basis for gas sales agreements in Australia. The terms and conditions for developing the project were further clarified in a Gas Agreement between the parties, signed in June 2002. In March 2002, the project signed up its first Australian customer when AGL agreed to purchase 50 PJ/a of natural gas from the project over a 20 year period (ITR 2002).

Coal-seam methane

4.42 Another potential source of gas in south-east Australia is coal-seam methane (**CSM**) extracted from coal beds in NSW and elsewhere.[27] CSM is currently produced in the Surat and Bowen Basins in Queensland for supply to Brisbane and other sites in Queensland. Feasibility studies are being conducted to assess the commercial viability of CSM sites at Camden near Sydney, in the Hunter Valley, and at Narrabri in northern NSW. At present none of these CSM sites has been demonstrated to be commercially viable. The most advanced of these feasibility studies is at Camden. Sydney Gas Company has developed a pilot project at Johndilo near Camden which it is confident will produce a minimum of 2 PJ per annum. The company has built a treatment plant and interconnected it with AGL's distribution system at Camden (Sydney Gas Company 2001a, pp.3-4). As part of its testing program, the company supplied gas into AGL's distribution system at Camden in 2001 (Sydney Gas Company 2001a, p.4). According to a June 2001 D&D Tolhurst research report on the company's website, Sydney Gas Company could provide up to 4 PJ in 2001/02 rising to a peak of almost 25 PJ in 2004/05 (Sydney Gas Company 2001b, p.3).

Processing plant capacity

4.43 The production capacity of the processing plants at Moomba, Ballera, and Longford affects whether more gas could readily be supplied in response to an increase in gas demand.

4.44 The Council does not have access to precise information on the production capacity of the Santos-operated plants at Moomba and Ballera. However, it is known that between them, the plants processed 232.4 PJ of natural gas in 1999-2000 (AGA 2001, p.59) and have been capable of supplying peak demand significantly above that level in conjunction with use of linepack capacity in the Moomba to Sydney Pipeline System and the Moomba to Adelaide pipeline system.

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27 Otherwise known as coal-bed seam methane or CSM.

4.45 The Longford plant, which processes gas from the Gippsland Basin, produced 202.2 PJ of natural gas in 1999-00 (AGA 2001, p.59) at a daily rate of up to 990 TJ/d (equivalent to a rate of 361 PJ/a) (Vencorp 2000, p.16). The *AGL Cooper Basin supply arrangements decision*, at 44,199, refers to an Australian Gas Association study projection which states that production limits on Gippsland Basin production were around 350 PJ/a at that time (1997), but with plans to increase production limits to 450 PJ/a. The Council understands the maximum daily capacity of the Longford plant to be about 1,100 TJ/d (over 400 PJ/a).

Transmission pipelines

Moomba to Sydney Pipeline System

4.46 Gas from the Moomba processing plant in the Cooper Basin is transported to Sydney, regional NSW, and the ACT via the Moomba to Sydney Pipeline System. The system currently has capacity to transport about 172 PJ/a, which could be expanded to more than 292PJ/a through the addition of up to six compressor stations (EAPL 1999b; EAPL 2001, sub.13, p.2).

4.47 The MSP Mainline terminates at Wilton just outside Sydney. Gas is conveyed from Wilton to users in the Sydney/ Newcastle/ Wollongong region through transmission pipelines and a distribution system owned by AGL Gas Networks Ltd (**AGLGN**).

4.48 The system also supplies natural gas via laterals to regional NSW and the ACT. Laterals branching off the MSP Mainline include the Young to Orange and Lithgow laterals, the Young to Wagga lateral, the Junee to Griffith lateral and the Canberra lateral. The system includes the portion of the Interconnect Pipeline owned by EAPL (Wagga to Culcairn), and connects with the APT-owned Central West Pipeline (Marsden to Dubbo).

4.49 The Moomba to Sydney Pipeline System was expected to transport about **[confidential information]** of gas in 2002 – about **[confidential information]**of total gas deliveries into NSW.[28] A significant proportion of the capacity of the Moomba to Sydney Pipeline System is committed under the Gas Transportation Deed (**GTD**) to AGL Wholesale Gas Limited (**AGLWG**). The terms of the

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28 See footnote 15.

GTD are outlined in paragraphs 4.104 to 4.110 and 7.593 to 7.616 of this report.

4.50 The Moomba to Sydney Pipeline System was constructed between 1973 and 1976 and commenced gas supply to Sydney in late 1976. From 1976-2000, the pipeline held a monopoly over the transportation of gas to most users in NSW and the ACT. [29]

4.51 The pipeline was originally owned by the Commonwealth Government and operated by a statutory authority, The Pipeline Authority. In 1994 it was sold to EAPL, a company owned by AGL, Petronas and TransCanada International. In December 1999, AGL acquired TransCanada's interest in EAPL, giving it a 76.48% interest in the Moomba to Sydney Pipeline System.

4.52 In June 2000, Australian Pipeline Ltd (**APL**) acquired all of the shares in EAPL, making APL the legal owner of the Moomba to Sydney Pipeline System. The beneficial owner of EAPL is the Australian Pipeline Trust (**APT**), a managed investment scheme. AGL holds 30% of the units in APT, and owns a 50% shareholding in APL. Marketing of transportation services on the Moomba to Sydney Pipeline remains a function of EAPL, but the pipeline is operated by Agility Management Pty Ltd, a subsidiary of AGL. The Council examines the corporate structure more closely in paragraphs 4.84 to 4.116 of this report; see also Attachments 2 and 3.

4.53 When the Moomba to Sydney Pipeline System was privatised, the *Moomba to Sydney Pipeline System Sale Act (Commonwealth) 1994* made provision for third party access to its services. The Trade Practices Commission (now the ACCC) was appointed to arbitrate in the event of an access dispute. These provisions were repealed when the Moomba to Sydney Pipeline System – including the MSP Mainline and the Canberra Lateral – became covered pipelines under the National Gas Code.

4.54 Coverage required EAPL, as owner/operator of the pipelines, to submit an access arrangement to the ACCC for approval under the National Gas Code (see paragraphs 3.20 to 3.22 of this report). In December 2000, the ACCC published a draft decision on EAPL's access arrangement. The ACCC proposed a number of amendments, including a significant reduction in tariffs.

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29 Some gas users in Albury (in NSW) were supplied with gas from Victoria. These users represented less than 4% of total gas use in NSW/ACT.

The Eastern Gas Pipeline

4.55 The Eastern Gas Pipeline (**EGP**), owned by the Duke Energy group of companies, was completed in August 2000. The pipeline has a current capacity of 65 PJ/a (Duke Energy 2002a), with scope to expand capacity through additional compression to 110 PJ/a (Duke Energy 1999, p.4).

4.56 The 795 km EGP extends from Longford in Victoria, through the towns and regions of Bairnsdale, Orbost, Bombala, Cooma, Nowra, Woollongong, Wilton, and into Horsely Park on the outskirts of Sydney. A pipeline linking the EGP to Canberra was opened in July 2002. The EGP to Canberra pipeline is owned by ActewAGL and operated by Agility, a wholly owned subsidiary of AGL.

4.57 As a result of the *Duke EGP decision* in May 2001, the EGP is not covered under the National Gas Code.

The Interconnect

4.58 The Interconnect Pipeline, completed in August 1998, runs from Barnawatha (Victoria) to Wagga (NSW), and links Victoria's GPU GasNet transmission network with the Moomba to Sydney Pipeline System. Gas can be transported from Longford to Sydney via a combination of the GPU GasNet transmission network, the Interconnect, the MSP lateral from Wagga to Young, and the MSP Mainline.

4.59 The section of the Interconnect between Barnawatha and Culcairn is owned by GasNet. EAPL owns the section between Culcairn and Wagga Wagga. For regulatory purposes, the service providers have rolled in their respective portions of the pipeline into their pre-existing networks. The Barnawatha to Culcairn portion of the pipeline has been rolled into the GPU GasNet transmission network, while Culcairn to Wagga has been rolled into the Moomba to Sydney Pipeline System.

4.60 The volume of gas that can be supplied through the Interconnect is limited by the degree of compression in the Victorian gas network and the capacity of the Interconnect. In particular, capacity constraints on the Victorian side of the border currently limit the capacity of the Interconnect to supply NSW markets to around 6.4 PJ/a (*Duke EGP decision 2001*, paragraph 122). Capacity could be increased with greater compression of the Victorian transmission system.[30]

4.61 The southbound capacity of the Interconnect is around 34 PJ/a, providing scope to increase northbound capacity through backhaul arrangements to 23-24 PJ/a (*Duke EGP decision 2001*, paragraph 122). The capacity of the Interconnect could be further expanded through additional compression and looping to as much as 90 PJ/a.[31] Existing booked capacity southbound on the Interconnect amounts to around 5 PJ/a (EAPL 1999a, p.9, *Duke EGP decision*, paragraph 122).

Total pipeline capacity to NSW/ACT markets

4.62 The capacity of transmission pipelines supplying NSW/ACT is summarised in Table 2.

30 According to GPU Gas Net, capacity to supply gas to NSW through the Interconnect depends on pressure in the northern Victorian system, which in turn depends on seasonal demand in Northern Victoria. Growth in demand in northern Victoria (approximately the area of the Victorian gas network north of the Melbourne city fringes) would displace approximately an equal amount of gas that could be supplied to NSW.

31 NSW Ministry of Energy and Utilities 1999b claims the Interconnect could be upgraded to around 90 PJ/a, while EAPL and the Gas Transmission Corporation of Victoria claim the Interconnect could eventually carry around 70 PJ/a.

Table 2: Capacities of pipelines supplying NSW and the ACT

Moomba to Sydney Pipeline System	
MSP Mainline	*Current:* 172 PJ/a (470 TJ/d) *Expandable to*: at least 292 PJ/a (800 TJ/d)
Canberra Lateral	*Current:* 16.8 PJ/a (46 TJ/d) *Expandable to*: EAPL proposed in 1999 to expand capacity to 21.2 PJ/a (58 TJ/d). EAPL has not implemented these plans. Pipeline could be further expanded through additional looping and compression.
Eastern Gas Pipeline	*Current*: 65 PJ/a (178 TJ/d) *Expandable to*: 110 PJ/a (300 TJ/d)
ActewAGL interconnector from EGP to Canberra	*Current*: 51 PJ/a (140 TJ/day) *Expandable to*: about 102 PJ/a (280 TJ/d)
Interconnect	*Current:* 6.4 PJ/a; could rise to 23-24 PJ/a through backhaul arrangements. *Expandable to:* 70-90 PJ/a, through additional compression and looping.

Note: some capacities stated in TJ/d and converted to PJ/a by converting at 365.25/1,000.

Sources: EAPL 1999a, p.8; EAPL 1999b, pp.32 – 34; EAPL, submission 13, p.2; ACCC 2000b, p.7; and ACT 2001, pp.20 – 21; Duke EGP decision, paragraph 122; NSW Ministry of Energy and Utilities 1999b; Gas Transmission Corporation of Victoria; www.duke-energy.com.au; information from ActewAGL.

Longford to Melbourne pipeline

4.63 The Longford to Melbourne pipeline, which supplies gas from the Gippsland Basin to Melbourne, is owned by GPU GasNet. The pipeline has a current capacity of 362 PJ/a (990 TJ/d). Vencorp is responsible for managing the operations of the principal transmission system in Victoria, including the Longford to Melbourne pipeline. The pipeline is covered under the National Gas Code and the ACCC has established reference tariffs for use of the pipeline. The tariff for transporting gas from Longford to Melbourne is about 21.4¢/GJ.

Moomba to Adelaide Pipeline System

4.64 The Moomba to Adelaide Pipeline System (**MAPS**), which supplies gas from the Cooper/ Eromanga Basin to Adelaide and regional South Australia, is owned by Epic Energy. The pipeline has a capacity of up to 153 PJ/a (418 TJ/d), of which about 127 PJ/a (348 TJ/d) is firm capacity throughout the year (ACCC 2001a, p.xiii). The Council understands that the pipeline is fully contracted until the end of 2005, with the major shippers being Terragas Trading, Australian National Power, and Origin Energy. The MAPS is covered under the National Gas Code. The ACCC, as regulator, has approved a reference tariff for transporting gas from Moomba to Adelaide of about 41¢/GJ[32] in 2002 (ACCC 2001a, ACCC 2002).

Ballera to Moomba Pipeline

4.65 The Ballera to Moomba Pipeline conveys semi-processed ("raw") gas from the SWQ Production facility at Ballera (Queensland) to the SACBUP production facilities at Moomba (in South Australia). Santos owns a 60% share in the pipeline, which is not a covered pipeline under the National Gas Code.[33]

4.66 The pipeline serves a dual purpose. First, it provides a means to dispose of liquid by-products from gas production at Ballera. The gas liquids (condensate and liquid petroleum gases) are shipped by pipeline to Port Bonython (South Australia) for processing and sale.

4.67 Second, raw gas shipped along the pipeline is processed into sales gas at the Moomba plant, and sold into South Australian and NSW/ACT markets. A significant proportion of South Australia's gas demand is currently sourced from Queensland via the Ballera to Moomba pipeline.

Victoria to Adelaide Pipeline (SEA Gas Pipeline)

4.68 Plans are well advanced to construct a new gas pipeline from Victoria's Otway Basin to Adelaide. Origin and International Power and TXU have entered a joint venture (known as **SEA Gas**) to build the 670 km pipeline. Natural gas would be supplied to the pipeline from the Minerva gas field in the Otway and the Yolla gas field in the Bass Basin, with the potential for additional gas to be sourced from the Origin-operated Thylacine and Geographe fields in the Otway Basin.

4.69 The Council understands that the SEA Gas Pipeline would have an initial capacity of 60-70 PJ/a, with a maximum expandable capacity of 125 PJ/a. First gas flows are scheduled for 2004.

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32 Epic Energy applied on 15 August 2002 for a review of the ACCC's decision on the Moomba to Adelaide Pipeline.

33 The National Gas Code does not apply to raw gas pipelines. See definition of "natural gas" in the Code.

4.70 As foundation customers, International Power and Origin Energy are understood to have contracted for 260 PJ and 270 PJ of gas respectively from BHP Billiton, to be shipped on the SEA Gas Pipeline over the first ten years (ESIPC 2002, p.40, SEA Gas 2002). Origin would sell gas as a retailer, while International Power would use gas for its Pelican Point and peaking power stations. TXU, which owns and operates South Australia's largest electricity generator, Torrens Island Power Station, will also be a foundation customer.

Tasmanian Gas Pipeline

4.71 In December 2001, Duke Energy commenced construction of a 350 km gas pipeline from Longford to Bell Bay in Tasmania, with subsequent development of pipelines to supply major sources of demand throughout Tasmania. The capacity of the pipeline is estimated at 40 PJ/a. As of October 2002, natural gas was flowing into Tasmania down to Bell Bay and south to Bridgewater (Duke Energy 2002).

Gas distribution in NSW / ACT

4.72 The Sydney gas distribution network is owned by AGLGN, a wholly owned subsidiary of AGL. The network is supplied by the MSP Mainline at Wilton just outside Sydney, and by the EGP at Horsley Park in Sydney. The Sydney region distribution system consists of two transmission pipelines (the Wilton to Newcastle and the Wilton to Wollongong pipelines) and a network of distribution pipelines. It supplies gas to industrial, residential, and commercial customers in Sydney, Newcastle, Wollongong, and Penrith. The system is covered under the National Gas Code, and is regulated by the Independent Pricing and Regulatory Tribunal of NSW (**IPART**). The regulator has set tariffs for use of the distribution system, with separate tariffs for the transmission pipelines within the system (IPART 2000b, pp.177-180).

4.73 The Moomba to Sydney Pipeline System also supplies AGL's distribution networks in regional NSW and the ACT. The regional distribution network extends to over 45 regional areas across NSW including coastal centres between Newcastle and the Hunter Region north of Sydney and Wollongong and Shellharbour south of Sydney. The distribution network also extends to the Riverina, Blue Mountains and the major centres of the Central Tablelands (AGL 2001b).

4.74 ActewAGL owns the ACT distribution system, which is supplied via the Canberra Lateral of the Moomba to Sydney Pipeline System, and will also be supplied via the EGP to Canberra pipeline. The ActewAGL system supplies gas to users in the ACT, Queanbeyan, and Yarrowlumla Shire.

Gas retail services

4.75 At present, AGL supplies users in NSW through two retail arms: AGL Retail Energy Limited (**AGLRE**), and AGL Energy Sales and Marketing Limited (**AGLES&M**). AGLRE services tariff customers (those taking less than 10 TJ/a). AGLRE serves about 800,000 residential customers (IPART 2001a, p.25), as well as commercial and small industrial customers. AGLES&M supplies contract customers (those taking over 10 TJ/a), of which there are around 500 (IPART 2001b, p.9).

4.76 Prior to the introduction of full retail contestability in January 2002, practical systems for switching smaller customers from one retailer to another were inadequate in NSW and the ACT. Consequently, customers were captive to incumbent retailers.

4.77 Prior to 2002, AGLRE supplied 96% of NSW customers using less than 10 TJ/a. In particular, it supplied all tariff users other than those in Wagga Wagga (supplied by Country Energy with gas supplied by the Moomba to Sydney Pipeline System), Cooma (supplied by Country Energy with gas supplied by the EGP), and Albury (supplied by Envestra with gas supplied by the Victorian transmission network) (AGA 2001, pp.36-37).

4.78 The introduction of full retail contestability in January 2002 has enhanced the potential for competition in gas retailing. In April 2002, the rate of customer transfer was about 1.96% on an annualised basis (Gas Market Company 2002). This low rate is likely to increase as customer awareness of contestability deepens, but suggests that the market remains in a transitional state at present.

4.79 As of July 2002, 14 parties were licensed to sell gas in NSW (IPART 2002), but many were inactive in the NSW market. A number of other licensees supply only their own large sites, or are active only in parts of regional NSW or the ACT.

4.80 IPART informs the Council that, as at July 2002, Energy Australia was the only gas retailer in Sydney independent of AGL (the other retailers were AGL Energy Sales and Marketing Ltd and AGL Retail Energy Limited).

4.81 While there are no figures on the share of sales to contract customers held by each of the active retailers, IPART considers that AGLES&M retains the majority of sales to contract customers (IPART 2001b, p.9).

4.82 There are currently two licensed retailers in the ACT: ActewAGL and Energex. ActewAGL is the only active retailer in the ACT, holding 100% of retail sales of natural gas to both large and small customers (ICRC 2001, p.5). ActewAGL is a 50-50 joint venture of Actew (publicly owned) and AGL.

4.83 Net retail margins in the Sydney region and the ACT are below 3% (IPART 2001a, p.27, ICRC 2001, p.v).

Vertical linkages

4.84 There are some vertical ownership and contractual linkages in the transmission, distribution, and retail gas chain in NSW and the ACT. The Australian Gas Light Company Limited (**AGL**) has an interest in each link in this chain. These interests are described in detail below.

4.85 The corporate and contractual structure within which the Moomba to Sydney Pipeline and AGL's gas distribution and retail systems are owned and operated is complex. That structure, and AGL's interest at each level, is set out in Attachment 2, which sets out the structure of APT, APL and EAPL; and Attachment 3, which sets out the ownership structure between EAPL and its ultimate holding company, APL.

Moomba to Sydney Pipeline System: ownership and operation

East Australian Pipelines Limited

4.86 The Moomba to Sydney Pipeline System is owned by EAPL. The legal owner of EAPL, through a complex corporate structure, is APL (see Attachment 3). The beneficial owner of EAPL is Australian Pipeline Trust (**APT**).

Australian Pipeline Trust

4.87 APT is a managed investment scheme which is registered with the Australian Securities and Investments Commission (**ASIC**) (ARSN 091 678 778) in accordance with the Corporations Act. AGL holds 30% of the units in APT. Petronas Australia Pty Limited (**Petronas**) holds 10% of the units and the remaining 60% is publicly held.

4.88 The responsible entity, or trustee, for APT is Australian Pipeline Limited (**APL**).

Box 1: Ownership Structure of APT

AGL holds a 30% unitholding in APT with another 10% being held by Petronas Australia, an original equity partner with AGL in the Moomba to Sydney pipeline. Petronas is the national petroleum company of Malaysia. Both AGL and Petronas Australia have undertaken that they will not dispose of their units in the Trust until, at the earliest, the release of the 2002 financial year results of the Trust.

Australian Pipeline Limited is the responsible entity for the Trust, and performs the functions of manager and trustee of the Trust. AGL holds a 50% interest in Australian Pipeline Limited. The Board of Australian Pipeline Limited comprises six directors of whom two are appointees of AGL, and one is an appointee of Petronas.

APT has lodged a compliance plan with ASIC as is required for a managed investment scheme. The Trust has a compliance manager who monitors performance by Australian Pipeline Limited of its obligations as responsible entity. The compliance manager performs a monthly review and provides a quarterly report to the Board.

source: APT 2001c, and EAPL 2001, sub. 13.

Australian Pipeline Limited

4.89 The shareholders of APL and their relevant shareholdings are:

(a) AGL - 50%, beneficially held (the legal owner is Leslie Fisk, Company Secretary of AGL);

(b) John Angus - 25%, legally and beneficially held (a partner at Freehill Hollingdale & Page); and

(c) James Graham - 25%, legally and beneficially held (a partner at Freehill Hollingdale & Page).

4.90 APL has six directors.

(a) Leslie Fisk (Company Secretary, AGL);

(b) John Fletcher (Group General Manager, Finance, AGL);

(c) Muri Muhammad (Vice President, Gas Business of Petronas);

(d) Thomas Ford;

(e) George Bennett; and

(f) Robert Wright.

4.91 The Prospectus states that APL has a majority of independent directors . It appears two directors have been appointed by AGL and one by Petronas. The information available on the remaining three directors suggests that they are independent of AGL and Petronas.

4.92 Non-director members of APL's senior management are:

(a) Ian Haddow;

(b) Michael McCormack;

(c) Austin James;

(d) James McDonald;

(e) Graeme Williams; and

(f) Kevin Dixon.

4.93 Four of this management team are listed in APL's 2001 Annual Report as having been employees of AGL prior to the establishment of APT.

Establishment of APT

4.94 Prior to the formation of APT, the series of companies in Attachment 3, now shown as owned by APL, were owned by AGL.

4.95 In 2000 AGL sold a substantial proportion of its gas transmission assets by way of a Share Transfer Agreement (**STA**) between APL as buyer and AGL as seller. Under the STA, AGL agreed to sell to APL all of the issued shares in the capital of APT Pipelines (then AGL Pipelines). This gave APL, and in turn APT, its interest in the Moomba to Sydney Pipeline System (see Attachment 3). AGL (and Petronas) undertook at the time of the sale not to dispose of the units they hold in the APT until, at the earliest, the release of the 2002 financial year results of APL.

4.96 The Moomba to Sydney Pipeline System was the largest asset in APT's portfolio at the time of the acquisition, forecast in Prospectus to represent approximately 53% of earnings before interest, income tax, depreciation, amortisation and abnormal items.

Relevant contractual arrangements

4.97 The Council has reviewed certain aspects of the relevant agreements between members of the Group from the disclosures made in APT's Prospectus and from the section of APT's 2001 Annual Report entitled "Related Party Disclosures" and from material made available to the Council by EAPL. Relevant aspects of each agreement are discussed in the balance of this section.

Pipeline Development Agreement

4.98 The Pipeline Development Agreement (**PDA**) is an agreement between AGL and APL. It has an initial term of 20 years and thereafter automatic rolling five year terms which are terminable on 12 months' notice. The PDA can also be terminated by either party if, at any time, AGL holds less than 20% of the issued units of APT for a continuous period of 90 days.

4.99 Under the PDA, APT has the right to acquire all or part of any new gas transmission pipeline opportunities developed by AGL. The parties agree to jointly seek out and examine the opportunities to develop projects and to jointly target businesses to acquire. In addition:

(a) Subject to any third party rights, AGL will have the first right of refusal to provide pipeline management services to any pipeline APL acquires or develops or in relation to which it has sufficient influence to determine the appointment of an operator.

(b) Subject to any third party rights, APL may not sell or otherwise dispose of any interest in any pipeline asset or ownership company or entity without first offering to sell that interest to AGL.

(c) For an initial term of 5 years and thereafter "as specified", AGL is retained by APL to provide such business development services as required by APL. This will result in a minimum payment to AGL of $250 000 per annum.

Pipeline Management Agreement

4.100 The Pipeline Management Agreement (**PMA**) was initially an agreement between APT Pipelines and AGL Infrastructure Management Pty Limited (**AGLIM**). AGLIM has since been renamed Agility Management Pty Limited (**Agility**).

4.101 The term of the PMA is 20 years (commencing on completion of the Share Sale Agreement between AGL and APL) and automatic rolling 5 year terms thereafter which may be terminated on 12 months' notice by either party.

4.102 Under the PMA, Agility provides technical services on an exclusive basis for the Moomba to Sydney Pipeline System (technical and marketing services are also provided for other pipelines). For the first two years of the PMA, AGLIM/Agility was also to provide transitional services as requested.

4.103 A fixed management fee of $6 million per annum is payable by APL to Agility under this Agreement. This sum is fixed until June 2005 but is reviewable thereafter. After 30 June 2005, APT Pipeline may request Agility to introduce contestability in the provision of certain services.

Gas Transportation Deed

4.104 The Gas Transportation Deed (**GTD**) is a deed between EAPL and AGL Wholesale Gas (**AGLWG**). It expires on 1 January 2017. The GTD was approved, following amendments, by the ACCC in March 2000, as an associate contract under the National Gas Code (ACCC 2000a).

4.105 From 1 July 2000 to 1 January 2007, AGLWG will pay a series of monthly minimum payments to EAPL. These payments will be offset against AGLWG's liability to pay for gas transported through the Moomba to Sydney Pipeline System as calculated by reference to the minimum published Reference Tariff. Where the minimum payment by AGLWG is insufficient to meet the cost of the gas transportation, AGLWG must pay extra to EAPL to meet the tariff payments. Credits will continue to accrue to AGLWG until 31 December 2006. During that period, EAPL has reserved pipeline capacity in favour of AGLWG.

4.106 As at 1 January 2007, any amounts not required to satisfy AGLWG's liability for transportation services are retained by EAPL. All credit amounts remaining from prior to that period become the property of EAPL and cannot be set off against AGLWG's liability to pay the tariff.

4.107 Liability to pay monthly amounts is unconditional but is liable to be suspended, reduced or eliminated in the same circumstances where the service contract in force between EAPL and AGL provides for the suspension, reduction or elimination of tariffs or payments generally.

4.108 During the period 1 January 2000 to 1 January 2003 AGLWG will receive 50% of the amount of revenue which EAPL receives from third parties using the Moomba to Sydney Pipeline System, where that use is in excess of the base calculated on the period 1 January 1999 to 1 January 2000. Any such payment to AGLWG would take the form of a reduction of the minimum monthly payments which AGLWG is required to make.

4.109 During the period to 31 December 2006, EAPL has reserved pipeline capacity in favour of AGLWG. That reserved capacity is not specified in the GTD. The Council estimates an annual reserved capacity equal to **[confidential information]**of total installed capacity in 2002, **[confidential information]**of total installed capacity in 2006.[34]

4.110 For the period starting 1 January 2007 and finishing on 1 January 2017, EAPL must provide AGLWG with a grant of transportation reservation to a maximum daily quantity of 162 TJ (approximately 34% of the current installed capacity from Moomba to Wilton. The tariff for the service will be the minimum published Reference Tariff from time to time. Tariffs will be varied in the event of a third party (or after 2006 a third party or AGLWG) acquiring comparable services at a lower tariff. AGLWG will have a contractual right to that lower tariff in respect of volumes provided for in the GTD but only to the extent (in terms of volume, capacity, other charges and period) that it was provided to the third party (or after 2006 the third party of AGLWG). Until 2007, changes in the published tariff set by the regulator will not impact on minimum monthly payments.

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34 The basis for these estimates is explained at paragraphs 7.599 – 7.600 of this report.

Distribution ownership

4.111 AGL wholly owns Agility Management Services, which is responsible for managing the operation and maintenance of the Moomba to Sydney Pipeline System and the ACT distribution system (AGL 2001a, p. 19).

4.112 AGL wholly owns AGLGN, which owns most of the distribution systems in NSW, including the Sydney region distribution system. AGLGN owns a 50% share in the ACT/Queanbeyan distribution system through its joint venture with Actew, called Actew AGL.

Retail ownership

4.113 AGL wholly owns two separate retailing arms, AGLRE, which sells gas to consumers taking less than 10 TJ/a, and AGLES&M, which sells gas to users taking more than 10 TJ/a.

Associate contracts: AGLWG

4.114 The National Gas Code requires contracts between covered pipelines and associates to be first approved by the relevant regulator. The regulator of AGLGN’s distribution network is IPART.

4.115 AGLGN signed associate contracts with AGLES&M for delivery of gas to 68 delivery points without first obtaining IPART’s approval. IPART later approved some of these contracts while AGL withdrew its application for approval of others. IPART has since released draft guidelines on associate contracts (IPART 2001c).

4.116 As discussed earlier, AGLWG holds a long-term take-or-pay contract with the SACBUP. This contract commits it to purchase gas from the SACBUP up to 2006 with specified contractual amounts that begin to wind down between 2001 and 2006. AGL’s GTD with EAPL underpins its take-or-pay contract with the SACBUP. The GTD ensures AGL has adequate capacity on the Moomba to Sydney pipeline to transport gas purchased under the take-or-pay contract to users in Sydney and regional NSW. The GTD extends beyond the life of the take-or-pay contract to provide a framework for AGL to negotiate transport capacity on the Moomba to Sydney pipeline until 2017 (EAPL 2001, sub.13). Compared with a base year of 1999, the GTD provides that in the period 1 July 2000 – 1 January 2003 AGLWG will receive 50% of any revenue received from third parties in excess of the revenue received from third parties in the 1999. This benefit will be enjoyed in the form of a reduction in the payments required from AGLWG (EAPL 2000a, p.66). As a result of this provision, EAPL loses half of any revenue generated in the period 1 July 2000 to 1 January 2003 from extra sales of transportation services to third parties above 1999 sales to those third parties.

Eastern Gas Pipeline

4.117 There are also some vertical ownership linkages on the Eastern Gas Pipeline (**EGP**):

(a) Duke Energy, the owner of the EGP, owns a retail trading arm, Duke Energy Australia Trading and Marketing Pty Ltd, which markets gas (including but not limited to gas transported on the EGP) to energy retailers in NSW and the ACT (Duke Energy 2000). Between September and October 1999, Duke Energy Australia Trading and Marketing Pty Ltd entered into gas sales contracts with three energy retailers operating in NSW, Citipower, Energy Australia, and Integral Energy (*Duke EGP decision 2001*, paragraph 30);

(b) Duke Energy owns a 86 MW gas-fired electricity generator at Bairnsdale, Victoria. Gas is supplied to the Bairnsdale Power Station by the EGP (Duke Energy 2002).

Well-head gas prices

4.118 Most gas sold from the Cooper Basin and the Gippsland Basin is sold under long-term contractual arrangements. Current contracted prices for wellhead gas in the Cooper and Gippsland Basins are not published. However, there is some information available on the wellhead price of gas sold out of the Gippsland Basin.

4.119 The Council notes that both basins have historically been in a position of monopoly supply to particular areas (Sydney, regional NSW and Adelaide in the case of the Cooper Basin; and Melbourne and regional Victoria in the case of the Gippsland Basin). This means that the historical price of gas from these basins may be above competitive levels.

4.120 Gippsland Basin gas is mainly sold in Victoria under a combination of pool and contract carriage arrangements and therefore is more susceptible to fluctuation than Cooper Basin well-head prices. This is because pool prices fluctuate according to daily changes in supply and demand while contract prices are set in advance and only fluctuate in response to contractual triggers such as annual price reviews.

4.121 A 1997 Victorian Auditor-General's report set out the terms of Gascor's take-or-pay agreement with Esso/BHP under which Gascor agreed to buy gas from the Gippsland Basin. The Gascor take-or-pay contract with Esso/BHP was struck as a settlement of the Petroleum Resource Rent Tax dispute in 1996 and may not reflect commercial bargaining. Under the agreement, Gascor agreed to pay a wellhead price from January 2000 of $2.35/GJ, with provision for annual indexation against the consumer price index, and pass-through of the GST (Victorian Auditor-General 1997, pp.249 - 251).[35] Given changes in CPI and the introduction of the GST in June 2000, the wellhead price of gas could now be expected to be over $2.70/GJ.

4.122 Vencorp supplies data on daily spot prices of Gippsland Basin gas. Parties can buy or sell gas on the spot market to supplement or reduce contracted amounts delivered through the Victoria's gas transmission network. Table 3 lists the monthly range of spot well-head prices for Gippsland Basin gas.[36] The Gippsland Basin spot price may be taken as a reasonable proxy for the wellhead price of Gippsland Basin gas.

35 The agreement provides that any party may seek a price review for the periods January 2004 to December 2006 and January 2007 to December 2009: Victorian Auditor-General 1997, pp.249 – 251.

36 Excludes transmission costs and the system operator's costs, totalling about $0.25/GJ.

Table 3: Gippsland basin well-head gas prices in $/GJ (exclusive of GST)

Month	*Min*	*Max*	*Note*
December 1999	2.36	2.38	
March 2000	2.55	2.57	
June 2000	2.56	4.34	generally around $2.56, with a one day price spike of $4.3408.
September 2000	2.56	2.57	
December 2000	2.57	2.57	
March 2001	2.67	2.71	
June 2001	2.61	2.98	
September 2001	2.61	2.70	
December 2001	2.61	2.63	
March 2002	2.69	2.72	

Source: Vencorp gas market reports (monthly)

4.123 From the above, a broad estimate of the underlying price of Gippsland Basin gas would be $2.65 – 2.80/GJ.

4.124 There is limited data on well-head prices at the Cooper Basin. The majority of Cooper Basin gas is sold under contract, including a long term take-or-pay contract between the SACBUP and AGLWG (IPART 2001b, p.29). The Tribunal in the *AGL Cooper Basin supply arrangements case* stated at paragraph 44,191 that the SACBUP and AGL agreed in 1988 to annual price escalations of 95% of CPI under the take-or-pay contract with price reviews available at the option of either party no more than every three years. The Tribunal stated that the 1993-94 well-head price of gas was $2.21/GJ. The 1999 well-head price was reported to be $2.40 (AGA 2001, p.77). Cooper Basin wellhead prices are likely to have increased since that time due to the impact of annual price review clauses in the contract between the SACBUP and AGL, and the impact of the GST.

Prices: transmission tariffs

Moomba to Sydney Pipeline

4.125 EAPL tariffs for transporting gas on the Moomba to Sydney Pipeline System include capacity and commodity charges.

4.126 From 1996 to June 2000, the published tariff for shipping[37] gas from Moomba to Wilton, near Sydney, was 71¢/GJ (APT 2000).[38] Tariffs rose as a result of the GST in June 2000, but EAPL simultaneously reduced the underlying tariff. The new tariff to transport gas from Moomba to Wilton was 66¢/GJ (excluding GST).[39] The price of transporting gas from Moomba to Canberra is currently 60¢/GJ.

4.127 As the Moomba to Sydney Pipeline System is covered under the National Gas Code, EAPL has submitted an access arrangement to the ACCC for approval. The ACCC released a draft decision in December 2000, proposing an average indicative tariff for shipping gas from Moomba to Sydney of 47¢/GJ over the period 2001-2005. It also proposed an average indicative tariff for shipping gas from Moomba to Canberra of 43¢/GJ (ACCC 20000b, p.119).

4.128 Tables 4 provides information on firm haulage tariffs from Moomba to Sydney, while Table 5 refers to Moomba to Canberra firm haulage services. Each table shows historical and current tariffs; and tariffs proposed by the ACCC in its December 2000 draft decision on the Moomba to Sydney Pipeline System access arrangement.

Wilton to Horsely Park pipeline

4.129 As the MSP Mainline terminates at Wilton, most customers located closer to Sydney must pay a tariff for transportation between Wilton and Horsley Park. This requires access to transmission pipelines owned by AGLGN and regulated by IPART.[40] The tariff for shipping gas from Wilton to Horsley Park fell from 23.5¢/GJ in mid-1999 to a regulated tariff of 3.71¢/GJ under a decision handed down by IPART

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37 Firm transport at 100% load factor. Future references to tariffs in ¢/GJ or $/GJ are based on the same assumption. Firm transport means transport with the guarantee that the gas will be delivered on the day and at the time specified in the contract. 100% load factor means that the user uses all of the capacity booked by it for any given day or time.

38 Converted from the published rate of $15.69/TJ/day/month/km for capacity plus a throughput related component amount described as "about 6% of the total cost of transportation". Calculations based on 100% load factor, 6% throughput charge, a distance from Moomba to Wilton of 1,299 km, and 30.4375 days/month.

39 The prices quoted in this section are GST-exclusive, unless otherwise stated.

40 The pipelines are regulated by IPART under a derogation in the NSW Gas Access Act from the provisions that would determine the ACCC as regulator. The derogation is in place until July 2007.

in July 2000. As a result, the total delivered price of gas from Moomba to Horsley Park fell significantly.

Table 4: Moomba to Sydney tariffs (Moomba to Sydney Pipeline System, $/GJ)

Moomba to Wilton (Sydney)	***Tariff excluding GST***	***Tariff including GST***
1. published tariffs		
1996 – June 2000	0.71	n.a.
since 1 July 2000	0.66	0.72
2. ACCC draft determination on MSP access arrangement		
2001	0.43	0.47
average 2001-2005	0.47	0.52
average 2001-2005 revised	0.50[41]	0.55

Sources: EAPL Access Arrangement Information: Moomba to Sydney Pipeline, 5 May 1999; ACCC 2000; information supplied by EAPL to the Council; Council calculations.

Table 5: Moomba to Canberra tariffs (Moomba to Sydney Pipeline System, $/GJ)

Moomba to Canberra	***Tariff excluding GST***	***Tariff including GST***
1. published tariffs		
1996 – June 2000	0.65	n.a
since 1 July 2000	0.60	0.66
2. ACCC draft determination on MSP access arrangement		
2001	0.40	0.44
average 2001-2005	0.43	0.47
average 2001-2005 revised	0.46[42]	0.50

Sources: EAPL Access Arrangement Information: Moomba to Sydney Pipeline, 5 May 1999; ACCC 2000; information supplied by EAPL to the Council; Council calculations.

41 The ACCC has advised the Council that regulatory approaches to the treatment of deferred tax has evolved since its 2000 draft decision, and that it may be appropriate to add back deferred tax liabilities for the purpose of tariff determination. The ACCC estimates that this would add about $0.03/GJ to MSP reference tariffs (ACCC 2002b, p.5). With this adjustment, the average 2001-2005 Moomba to Sydney tariff would rise to $0.50/GJ. The average Moomba to Canberra tariff would rise to $0.46/GJ.

42 See footnote 41.

Eastern Gas Pipeline

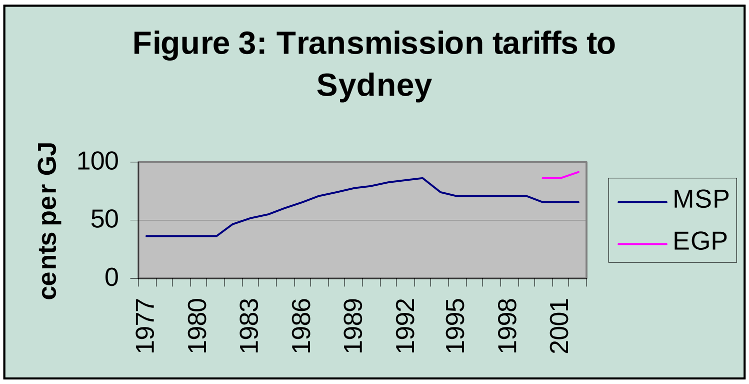
4.130 Duke Energy publishes tariffs on its website for transporting gas on the EGP.

(a) Until December 31 2001, the EGP tariff for shipping gas from Longford to Horsley Park outside Sydney was about 86¢/GJ excluding GST. The tariff from Longford to the offtake point of the EGP Lateral to Canberra was 65¢/GJ.

(b) Effective 1 January 2002, the Longford to Sydney tariff was raised from 86¢/GJ to 91¢/GJ. The tariff from Longford to the offtake point of the EGP Lateral to Canberra was raised from 65¢/GJ to 69¢/GJ.[43]

(c) EGP tariffs will escalate once again on 1 January 2003, with ongoing annual escalations, in accordance with a formula based on movements in the Consumer Price Index (Duke Energy 2001b, p.5).

4.131 A comparison of tariffs for shipping gas to Sydney on the Moomba to Sydney Pipeline System and the EGP appears at Figure 3. The chart compares prices since the opening of the Moomba to Sydney Pipeline System in 1977.[44]



[43] 1 January 2002 calculations: Single forward haul rate of $0.9095/GJ to Zone 3, which includes Horsley Park, Wilton, and Sydney, and forward haul rate of $0.6875 to Zone 2, which includes the Canberra Lateral offtake point.

[44] Note that the MSP Mainline terminates at Wilton, while the EGP terminates at Horsely Park. The MSP Mainline interconnects with the AGLGN Wilton to Horsely Park transmission pipeline. The regulated tariff on the AGLGN Wilton to Horsely Park pipeline is $0.04/GJ. See paragraph 4.129.

Other pipelines

4.132 The regulated tariff for shipping gas from:

(a) Longford to Melbourne on the Longford to Melbourne pipeline is about 21.4¢/GJ;

(b) Moomba to Adelaide on the Moomba to Adelaide pipeline is 41¢/GJ.[45]

4.133 These are regulated tariffs under the National Gas Code (GasNet 2001; ACCC 2001a).

Delivered gas prices

4.134 The delivered price of gas can vary according to the quantity of gas contracted. For residential and commercial users, the delivered price includes a gas commodity charge (based on the wellhead price of gas), a gas transmission charge, distribution charges, and retail charges. Commercial users expect lower prices per GJ because of higher rates of consumption. Industrial users are likely to pay lower or zero retail charges, and lower distribution charges, than commercial users. Very large industrial users may take gas directly from the transmission system – and pay minimal or no distribution or retail charges.

4.135 Delivered gas prices are not typically disaggregated into component charges such as the gas commodity charge, the transmission transport charge, the distribution charge, and the retail charge. It is understood that very large industrial customers have been able to negotiate delivered prices under which components have been disaggregated to some extent, and with provision for reductions in delivered prices where component charges fall (eg., where transmission transport tariffs fall due to regulation).

4.136 Table 6 provides estimates of delivered gas prices (exclusive of GST) to the city gate in a number of Australian cities. The estimates of well-head prices should be regarded as broad estimates only. The estimates exclude distribution and retail charges.

45 Epic Energy applied on 15 August 2002 for a review of the ACCC's decision on the Moomba to Adelaide Pipeline.

Table 6: 2001 Citygate gas prices: Sydney, Melbourne, Canberra, Adelaide, Perth

NSW	*current prices in $/GJ (GST exclusive)*
(a) Cooper Basin gas shipped via Moomba to Sydney Pipeline System (MSP)	
Wellhead price at Moomba	$2.60[46] approx
Haulage on MSP to Wilton	$0.66 ($0.50 revised ACCC proposed tariff[47])
Wilton to Horsely Park (AGL)	$0.04
Sydney citygate (via MSP)	**$3.30** ($3.14 with revised ACCC proposed tariff)
(b) Gippsland Basin gas shipped via Easter Gas Pipeline (EGP)	
Wellhead price at Gippsland Basin	$2.60 – $2.80 approx
Haulage on EGP to Sydney	$0.91
Sydney citygate (via EGP)	**$3.51 – 3.71**

46 Derived from 1999 estimate of wellhead prices of $2.40/GJ (AGA 2001, p.77), escalated as provided for in the contract between AGL and the SACBUP by 95% of CPI.

The date of the 1999 estimate is not identified in AGA 2001, or in the Port Jackson report cited as the source for the estimate. If it was based on June 1999 prices, the wellhead price would have escalated to around $2.62/GJ. Based on December 1999 prices, the wellhead price would have escalated to around $2.57/GJ. The Council has selected a midpoint tariff of $2.60/GJ.

The CPI (weighted average of eight capital cities) escalated 9.4% between June 1999 and June 2001, and 7.8% between December 1999 and June 2001: Australian Bureau of Statistics 2001.

47 See Table 4.

ACT	*current prices in $/GJ*
Wellhead price at Moomba	$2.60 approx
Haulage on Moomba to Sydney Pipeline System to ACT	$0.60 ($0.46 revised ACCC proposed tariff[48])
ACT citygate 2001 (via MSP Mainline and Canberra Lateral)	**$3.20** ($3.06 with revised ACCC proposed tariff)
Gippsland Basin price	$2.60 – $2.80 approx
Haulage on Eastern Gas Pipeline to ACT	$0.69
Haulage on EGP-Canberra interconnector owned by ActewAGL	tariffs are rolled into ActewAGL distribution tariffs
ACT citygate (via EGP)	**$3.29 – $3.49**

Victoria	*current prices in $/GJ*
Ex-plant	$2.60 – $2.80 approx
Haulage to Melbourne (via Longford to Melbourne pipeline)	$0.21 plus Vencorp charges of around 4¢/GJ (under ACCC 1998)
Melbourne citygate	**$2.85 – $3.05**

South Australia	*current prices in $/GJ*
Ex-plant	$2.60 approx
Haulage to Adelaide (via Moomba to Adelaide pipeline)	$0.41 under ACCC final decision 2002 (0.60 previously under published tariffs)
Adelaide citygate	**$3.01** ($3.20 under previous published tariffs)

48 See Table 5.

Western Australia	*current prices in $/GJ*
Ex-plant	$1.90
Haulage to Perth (via Dampier to Bunbury Natural Gas Pipeline)	$1.00 ($0.75 under draft decision of Western Australian Office of Gas Access Regulation 2001)
Citygate (Perth)	**$2.90** ($2.65 under draft regulatory decision)

source: Australian Gas Association 2001; ACCC 2001a; ACCC 2000b; ICRC 2001, p.11; ACCC 1998; Duke Energy 2001b; Western Australian Office of Gas Access Regulation 2001; Vencorp gas market reports (monthly). Tariffs calculated on basis of 100% load factor.

Transport costs in relation to delivered prices

4.137 The significance of transport costs in delivered gas prices can vary depending on the difficulty of collecting the gas, the cost of laying the transmission and distribution pipelines, distances between the gas basin and customers, and the characteristics of particular gas customers.

4.138 The ACT regulator, the Independent Competition and Regulatory Commission (**ICRC**) estimated that for ACT domestic users, gas and transmission costs represent around 40% of total delivered gas costs, while distribution charges contribute 48%, and retail costs and margins 12% (ICRC 2001, p.10). Larger industrial users pay much lower distribution and retail charges than commercial or residential users, meaning that transmission charges represent a much larger share of their final price for delivered gas.

4.139 In 1999 NSW/ACT transmission charges represented around 5% of the final price of gas for residential users, 12% for commercial and smaller industrial users, and could represent up to 20% of charges for large industrial users.[49] Incitec has informed the Council that gas transmission charges represent about 15% of the company's delivered gas costs.[50]

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49 Based on transmission tariff on the Moomba to Sydney Pipeline System of 66¢/GJ (current published tariff) and final delivered prices of $13.72/GJ for residential users, $5.49 for small commercial users (AGA 2001, p.77), and as low as $3.30/GJ for large industrial users (see Table 6).

50 Incitec, a major manufacturer and distributor of nitrogenous products, is one of the largest gas users in NSW. Incitec consumes some 10.5 PJ/a (around 9% of total NSW gas demand in 2001).

4.140 Based on these 1999 figures, a 10% rise in transmission tariffs would raise delivered gas prices for residential users by 0.5%, for commercial users by 1.2%, and about 2% for large industrial users (based on assumptions in previous paragraph).

NSW and ACT demand

4.141 Growth in demand for gas in NSW is closely linked to the installation of major new gas-fired power generation and cogeneration capacity. Forecasts of long-term growth in NSW gas demand are subject to considerable uncertainty, principally because trends in gas-fired electricity generation are unclear. Some major new projects may come onstream later than originally anticipated (ACCC 2000, pp.91, 99-101).

4.142 EAPL submitted demand forecasts to the ACCC as part of the regulatory process on the Moomba to Sydney Pipeline System. The ACCC indicated in its draft determination on the proposed access arrangement that it would accept these forecasts, which cover NSW demand in aggregate, as well as demand for services on the Moomba to Sydney pipeline. The forecasts are summarised in Table 7.

4.143 The EAPL forecasts assume that shipments on the Moomba to Sydney Pipeline System will decline for a period after 2000 following the opening of the EGP. This trend reverses sharply from about 2005, with rising demand for gas associated with the installation of major gas-fired power generation and cogeneration capacity (ACCC 2000b, p.93).

4.144 EAPL has provided confidential information that the Moomba to Sydney Pipeline System is expected to deliver **[confidential information]** for AGLWG (FY2002). This represents **[confidential information]**of the pipeline's expected deliveries of **[confidential information]** in FY 2002, and **[confidential information]**of the total gas deliveries in NSW in FY2002 (EAPL 2002, p.4). This would indicate total NSW demand of **[confidential information]**. The Council notes from this information that **[confidential information]**.

Table 7: Forecast Volumes on the Moomba to Sydney Pipeline System (in PJ), 1999 to 2014.

	1999	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2008*	*2010*	*2012*	*2014*
NSW/ACT Demand	111.8	109.6	109.4	113.3	117.4	124.1	138.9	159.1	179.7	196.4	204.2	211.2
Volumes transported on Moomba to Sydney Pipeline System[a]	117.7	117.2	99.4	89.8	91.4	89.9	97.9	118.1	130.7	147.4	170.2	198.2

Source: ACCC 2000b, p.91.

[a] May include gas from Gippsland Basin transported via the Interconnect.

Note: These are the most recent published figures. The Council relies on more recent (confidential) forecasts in parts of this report.

Gas demand price elasticity

4.145 A reduction in gas transport costs can make gas a more attractive source of energy. Historically, however, the demand for gas transport services has been relatively inelastic in the manufacturing and commercial sectors.

4.146 The price elasticity of demand refers to the responsiveness of gas demand to price movements. The most recent information available on the price elasticity of gas demand was prepared by the Australian Bureau of Agricultural and Resource Economics (**ABARE**) for the Australian Gas Association (AGA 1996). The study was conducted on data covering the period 1973-74 to 1993-94.

4.147 The AGA/ABARE paper disaggregated price elasticities for the following sectors of energy use: residential commercial and industrial. The study did not cover the use of gas for energy conversion (AGA 1996, p.29).

4.148 The analysis reported on the long-term price elasticity of demand for gas in response to a 1% change in the price of gas. Long-term price elasticity data allows time for users to respond to price changes by adjusting their demand for energy or switching between energy sources.

4.149 Table 8 presents the outcome of the analysis. In addition, the table reports the share of total gas demand accounted for by each sector in 1998-99 in order to derive a weighted elasticity for NSW/ACT.

Table 8: Price elasticity of demand for gas

Per cent change in demand for gas by sector	***Change in Demand in response to a one per cent change in price***	***Sector share of total gas use (as percentage)***
Residential	- 0.78	14.5%
Commercial	- 0.10	11.9%
Manufacturing (industrial)	- 0.30	60.7%
Weighted (by sector share)	- 0.31	87.1% (remainder of gas use described as 'all other')

Source: Australian Gas Association 1996, p.22; Australian Gas Association 2001, p.56.

Interpretation: The result for the residential sector means that demand for gas would fall by 0.78% following a one per cent rise in gas prices. The result allows time for parties to switch between energy sources or adjust overall demand.

4.150 The results indicate quite inelastic long-term demand in the manufacturing and commercial sectors, but reasonably elastic long-term demand in the residential sector. As the manufacturing and commercial energy users represent around 72.6% of total demand, the statistics suggests demand is relatively inelastic for the majority of demand. Further, the manufacturing and commercial users represent those sectors with the highest potential for growth.

4.151 The Council notes that the AGA/ABARE study mainly covers the 1970s and 1980s, and the outcomes need to be interpreted with caution. In particular, the characteristics of demand are likely to have changed since that time. In addition, the calculations excluded the use of gas for energy conversion (AGA 1996, p.29). The Council notes elsewhere in this report that elasticity of demand in this sector is likely to be higher than the averages represented in the AGA/ABARE study (see paragraphs 7.419 to 7.430 of this report).

NSW / ACT gas supply arrangements

4.152 Until 2000, gas supplied to most areas of NSW and the ACT was sourced from the Cooper Basin and shipped via the Moomba to Sydney Pipeline System. A second source of gas supply was introduced in September 2000 when the EGP commenced shipments of gas from the Gippsland Basin to Sydney and surrounding areas.[51]

4.153 The opening of the EGP accompanied a series of national gas reforms, including regulatory reforms, disaggregation of the old vertically integrated transport and supply monopolies, and implementation of the National Gas Code.

4.154 Over time, there is potential for these developments to lead to the disaggregation of gas and gas transportation contracts for larger users, entry in the retail sector by new retailers and aggregators, and the development of new services such as interruptible services.

4.155 There is evidence of emerging competition between sources of gas supply in NSW/ACT gas sales markets.

Third party access to pipelines

4.156 EAPL has reported that, as at September 2001, there were three shippers on the Moomba to Sydney Pipeline System, other than AGL (EAPL 2001, sub.13, p.3). AGL reports that in 2000-2001, it transported about 23.2 PJ through its transmission and distribution

51 Interconnection between the EGP and the ACT occurred in July 2002.

network under third party contracts. These loads would likely have derived from third party contracts for shipping on the Moomba to Sydney Pipeline System or the EGP (AGL 2001a, p.17).

EGP services

4.157 It is understood that the EGP transports around 20-25 PJ of gas into the Sydney region (ACCC 2000b, p.98; Gas Advice 2001, sub.5, p.7). The Council understands that 20 PJ is contracted to foundation customers of the EGP (being BHP at Port Kembla and the Sithe Cogeneration plant at Smithfield). Further sales have been achieved by Duke Energy's retail arm (Duke Energy Australia Trading and Marketing Pty Ltd) acting as a wholesale supplier.

4.158 Esso/BHP Petroleum signed a gas transportation agreement with Duke Energy in 1998 coincident with the contract for the sale of the EGP project by BHP Petroleum and Westcoast to Duke Energy. Under the gas transportation agreement, Esso and BHP Petroleum contracted for 80 TJ/d capacity on the EGP, which is roughly 29 PJ/a at 100% load factor, or 23 PJ/a at 80% load factor.

4.159 There are conflicting views about the success of gas transported via the EGP in achieving sales in Sydney and surrounding areas. EAPL argues that it lost approximately 20% of its annual capacity within one year of the entry of the Eastern Gas Pipeline (EAPL, submission 13, p.4). On the other hand, GasAdvice's submission argues that:

> *… While the EGP is currently estimated to be supplying around 25 PJ per annum out of a total demand of around 110 PJ per annum, there have been very limited numbers of gas users which have switched from Cooper Basin to Gippsland Basin supply sources. Putting aside the contracted loads for BHP and One Steel at Port Kembla and the Sithe cogeneration plant at Smithfield (approximately 20 PJ per annum and which were foundation customers used to underwrite the development), only an estimated 5 PJ of additional load has since transferred to be supplied through the EGP rather than the Moomba to Sydney pipeline.* (GasAdvice 2001, sub.5, p.7)

4.160 In other words, GasAdvice's view is that apart from foundation customers buying gas under long-term contracts few users have switched to gas supplied by the Eastern Gas Pipeline.[52]

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52 Further information on NSW/ACT downstream gas sales markets is provided from paragraph 7.206 of this report.

5 Applying the coverage criteria

5.1 In recommending whether coverage of a pipeline should be revoked, the Council must consider whether the pipeline meets the coverage criteria in s.1.9 of the National Gas Code (see below).

Section 1.9 coverage criteria: National Gas Code

The Council cannot recommend that coverage of a pipeline be revoked if the Council is satisfied of all of the following matters set out in s.1.9 of the National Gas Code:
(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.
The Council must recommend revocation of coverage (either to the extent described, or to a greater or lesser extent that that described in the application) if the Council is not satisfied of one or more of the s.1.9 criteria.

Source: National Gas Code, sections 1.9, 1.31

5.2 The Council sets out its assessment of the EAPL applications against each of the coverage criteria in sections 6-9 of this report. Below, the Council provides general comments on its approach to the criteria. The Council also considers a number of general matters of relevance to all of the criteria, including specification of the application pipelines and their services; and the Council's approach to market analysis.

5.3 For the Council to recommend against revocation of coverage, it must be "affirmatively satisfied" of the matters set out in s.1.9.[53] In making its assessment, the Council must comply with the duties imposed upon it under the general principles of administrative

[53] *Sydney Airport decision* at paragraphs 23, 100, 189, 206, 208, 212, 216, 217, 219.

decision-making. Provided an administrative decision maker reaches a decision within these general principles, the way in which the decision maker approaches a decision is not otherwise prescribed by the law. There are a "whole range of possible approaches to decision-making", the correctness of any one approach depending on the circumstances of the particular case.[54]

5.4 The Council presents its analysis of the coverage criteria in the following order: criterion (b); criterion (a); criterion (c); criterion (d).

5.5 The Council considers it logical to begin with criterion (b), as it focuses on the service to which access is sought and asks whether the pipeline providing that service is a natural monopoly.

5.6 Criterion (a) is wider in scope as it requires consideration of industry structure and whether the service provider is able to exercise market power in relation to dependent markets. Criterion (a) also raises the issue of access, testing whether a pipeline is a "bottleneck" facility. While natural monopoly characteristics is a necessary pre-condition for a pipeline to be a "bottleneck," it also requires that the pipeline occupies a strategic position in a supply chain.

5.7 The Council's approach in assessing criterion (b) ahead of criterion (a) is consistent with the Tribunal's approach in the *Duke EGP decision*.

Interpreting the criteria

5.8 In interpreting the coverage criteria, the Council has used general principles of statutory interpretation and has accorded primacy to the language of the Gas Access Acts and the National Gas Code. In considering certain aspects of the EAPL applications, it has been necessary to have regard to the following additional matters in interpreting the legislation:

(a) The Tribunal's *Duke EGP decision*, and the Tribunal's decisions in relation to declaration applications under Part IIIA of the TPA. Decisions under Part IIIA are relevant because the words of the declaration criteria in sections 44G(2) and section 44H(4) of the TPA raise the same issues

54 See *MIEA v Wu Shan Liang* (1996) 185 CLR 259 at 282; also *John Meadows & Sornawathy Meadows v Minister for Immigration and Multicultural Affairs* (unreported, Einfeld, von Doussa and Merkel JJ, 23 December 1998) especially at p. 12 per Einfeld J.

as those raised by the coverage criteria. The declaration criteria have been considered by the Tribunal in the *Australian Union of Students decision*[55] and the *Sydney Airport decision*.[56]

(b) The purpose sought to be achieved by enacting the Gas Access Acts of NSW, South Australia, Queensland, ACT, and the Commonwealth.[57] Reference has been had to the preambles to each of the Gas Access Acts to determine this purpose.

5.9 In addition, the Council has regard to economic literature covering issues raised in the EAPL applications. The Council has particular regard to the work of Janusz A Ordover and William Lehr, *Should Coverage of the Moomba to Sydney Pipeline be Revoked?* (Ordover and Lehr 2001), which focuses specifically on issues raised by the EAPL applications.

The application pipelines

5.10 'Pipeline' is defined in the National Gas Code and the GPAL as a pipe or system of pipes for transporting natural gas and tanks, machinery, etc attached to the pipes, but does not include any facilities of the upstream processing plant, or anything downstream of the connection point to the consumer.[58]

5.11 The two pipelines for which revocation of coverage is sought are:

(a) the MSP Mainline; and

(b) the Canberra Lateral.

5.12 The MSP Mainline supplies gas to:

(a) Wilton (from where it is transported to Sydney via the AGL-owned Wilton to Horsley Park pipeline);

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55 *Re Australian Union of Students* (1997) ATPR 41-573.

56 *Sydney International Airport* (2000) ATPR 41-754.

57 Section 33, *Interpretation Act, 1987* (NSW); section 15AA, *Acts Interpretation Act, 1901* (Commonwealth).

58 Section 2, GPAL read together with s.10.8 of the National Gas Code.

(b) points along its route, including Goulburn, Marulan, Moss Vale, and Bowral; and

(c) the offtake points of lateral pipelines branching off it, namely the APT Central West System, the Young to Lithgow pipeline (and associated spurs to Bathurst, Orange and Oberon), the Young to Culcairn pipeline and the Canberra Lateral.

5.13 The Canberra Lateral branches off the MSP Mainline at Dalton and runs to North Watson in the ACT. It supplies gas to the distribution system operated by ActewAGL, which supplies Canberra in the ACT, and Queanbeyan and the Yarrowlumla Shire in NSW.

Services of the pipelines

5.14 'Service' is defined in the National Gas Code to mean a service provided by means of a Pipeline including (without limitation) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul), the right to interconnect with the pipeline and ancillary services.[59]

5.15 Natural gas transportation services can generally be further classified into *firm* or *interruptible* transportation services. With a firm transportation service, the user is guaranteed delivery of gas at all times, while with interruptible services the pipeline operator reserves the right to interrupt the transportation service at any time (generally in times of peak demand). Interruptible services are accordingly less reliable than firm services and could be expected to be cheaper. Providing this range of firm and interruptible services enables the pipeline owner to maximise usage by the highest paying source of demand.

5.16 *Backhaul* refers to arrangements for the supply of gas from a producer to a user in circumstances where the user is located upstream of the point on the pipeline where the producer can inject the gas. The user's requirements are physically met by gas diverted from another producer.

5.17 *Interconnection* is the right to join other pipelines with the relevant pipeline (the subject of the coverage application). A party may wish

59 S.10.8 of the National Gas Code.

to interconnect a pipeline with one or more of the pipelines for which revocation is sought to open up new supply possibilities.

5.18 *Linepack* is another service third parties may seek. It is typically sought by users to assist in balancing small fluctuations in their daily demand, and can therefore be viewed as a service ancillary to gas transportation.

5.19 The Council considers that for the purposes of considering these coverage applications, it is not necessary to define every possible gas transportation service.

Geographic scope of pipeline services

5.20 In the *Duke EGP decision*, the Tribunal considered whether a transportation service is a point to point service or a more broadly defined services of transporting gas from any source and, separately, transporting gas to a particular destination or region.

5.21 The Tribunal found that the relevant service is the thing that is bought and sold, or for which there are potential transactions. The Tribunal held that the relevant service provided by the EGP was a haulage service for the transport of gas between one point on the pipeline and another:

> *The question of what constitutes the services provided by the pipeline is fundamentally a mixed question of fact and the proper construction of criterion (b), rather than a matter of economic analysis. Every haulage service will of necessity be from one point to another. That is the commercial service actually provided by the pipeline operator to its customers. That service may be of different use to the producers in the origin market or to the customers in the destination market, but it is the same service* (Duke EGP decision 2001, paragraph 69).

5.22 Consistent with the Tribunal's approach, the Council concludes that the services provided by the MSP Mainline and the Canberra Lateral are the transport of natural gas from the production fields in the Cooper Basin to downstream gas sales markets in NSW and the ACT. In particular:

(a) the *MSP Mainline* provides natural gas transport services from Moomba to Wilton (near Sydney) as well as to points in between including the exit flanges for various laterals along the length of the MSP Mainline (such as the Canberra Lateral)[60]; and

(b) the *Canberra Lateral* provides natural gas transport services from Dalton (the relevant exit flange on the MSP Mainline) to North Watson in the Australian Capital Territory as well as to points in between.

Market analysis

5.23 In considering market definition, the Council is guided by the decisions of the Federal Court, the Tribunal, and the High Court in their consideration of market for the purposes of Part IV; as well as the Tribunal's and the Court's consideration of Part IIIA.

5.24 The Tribunal has defined 'market' in the following way:

> *A market is the area of close competition between firms, or putting it a little differently, the field of rivalry between them (if there is no close competition there is of course a monopolistic market). Within the bounds of a market there is substitution – substitution 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.* (Re Queensland Co-operative Milling Association Ltd (1976) 25 FLR 169 at 190).

5.25 This view of market has been accepted by the High Court in *Queensland Wire Industries Pty Ltd v The Broken Hill Pty Ltd 1989* 167 CLR 177 (***Queensland Wire***) and has been adopted by the Tribunal in the context of Part IIIA (*Sydney Airport decision 2000*, paragraph 91).

5.26 Ordover and Lehr discuss the definition of "market," and some of the difficulties in delineating market boundaries, as follows:

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60 The MSP Mainline also provides part of a natural gas transport service from Longford (Bass Strait) to Sydney, incorporating the following pipelines: the Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline. That part of the service provided by the MSP Mainline is between Young and Sydney. The relevant volumes are about 3% of all gas shipped on the Moomba to Sydney Pipeline System in 2002, forecast to rise to about 16% in 2010 (ACCC 2000b, p.91, Table 2.24).

> *Two goods are in the same market when they are good substitutes for each other. Two goods are deemed substitutes if an increase in the price of one leads to an increase in the demand for the other (i.e., the cross-price elasticity of demand is positive). Hence, the relevant market should include all those products that are close substitutes for the product in question and exclude those products which are either not substitutes or very weak substitutes for the product in question. Unfortunately, it is often not a trivial matter to obtain with econometric methods statistically meaningful estimates of all the pertinent cross-elasticities of demand. Moreover, even when such cross-elasticities can be estimated, there is still a threshold question of what is the proper cut-off for inclusion of the product in the relevant market.* (Ordover and Lehr 2001 p.9)

Dimensions of markets

5.27 Markets can be distinguished in a number of ways, each of which is relevant to issues of market delineation for the purposes of coverage criterion (a). The principal dimensions are set out below.

5.28 The *product* dimension relates to the type of goods and services produced. Product markets can be considered separate if their respective products are not substitutable in demand or supply. Products are substitutable in demand (and are therefore in the same product market) if consumers will substitute one product for the other following a small but significant change in their relative prices. Substitution in supply occurs when a producer can readily switch its assets from producing one product to another.

5.29 *Functional* delineation focuses on the different steps in a production process. In defining functional markets, the Council has had regard to the Tribunal's approach to functional market delineation in the *Sydney Airports decision 2000* (paragraphs 91-99). This approach is consistent with the High Court's approach in *Queensland Wire* and the approach developed by Mr Henry Ergas (Ergas 1997, pp.1-3). The Council considers that the following two conditions must be satisfied for markets to be regarded as functionally separate:

(a) the layers at issue must be separable from an economic point of view (*economically separable*). This involves an assessment of whether the transaction costs in the separate provision of the good or service at the two layers are so large as to prevent such separate provision from being feasible. In effect, to be in different markets, vertical integration must not be inevitable; and

(b) each layer must use assets sufficiently specific and distinct to that layer such that the assets cannot readily produce the output of the other layer (*economically distinct*). In effect, supply side substitution must not be so readily achievable as to unify the field of rivalry between the two layers.

5.30 The geographic dimension of the market refers to the geographic area that corresponds to the commercial realities of the industry and represents an economically significant trade area. (Bender 1981, quoted with approval by the Federal Court in *Australia Meat Holdings Pty Ltd v TPC* (1989) ATPR 40-932 at 50,011).

5.31 The *temporal dimension* of the market refers to the period over which substitution possibilities should be considered. This may impact on how broadly the market is defined. With a longer time dimension, the ability of consumers to substitute to other sources of supply in response to a price increase is likely to be greater. For example, with a sufficiently long time dimension, gas consumers can switch to alternative fuels (e.g. oil) or sources of power (e.g. electricity) in response to an increase in the price of natural gas.

5.32 A reasonable timeframe for delineating a market should allow scope for demand and supply substitution (that is, changes in the product mix) to occur. In examining supply-side substitution, the examination is of those suppliers who can readily switch production or service provision to production of the product at issue.

6 Criterion (b)

that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline;

6.1 In analysing criterion (b), the Council's task is to:

(a) define the services provided by the MSP Mainline and the Canberra Lateral; and

(b) assess whether it is economic to develop another pipeline to provide these services.

6.2 The Council notes that EAPL has not relied on criterion (b) to support its applications to revoke coverage of the MSP Mainline and Canberra Lateral. EAPL stated in its first submission to the Council that it:

> *… does not seek revocation in this application based on [criterion (b)]. It takes the position, however, that in certain circumstances the Minister would be required to revoke coverage based on [criterion (b)] and reserves its right to make an application based on [criterion (b)] in future.* (EAPL 2001, sub.6, p. 2)

6.3 In assessing criterion (b), it is necessary to clarify the use of the terms "develop another pipeline" and "uneconomic."

Develop another pipeline

6.4 In considering whether it is uneconomic to develop another pipeline, it is appropriate to have regard to pipelines that have already been developed *(Duke EGP decision 2001,* paragraph 57*).*

6.5 The term "develop" is sufficiently broad to encompass modifications or enhancements to existing pipelines. Thus, if an existing pipeline does not presently provide the services provided by the pipeline in question, but could economically be modified or expanded to do so, then criterion (b) is not met. This is consistent with the Tribunal's approach in the *Duke EGP decision* (paragraphs 55-57).

6.6 In the present case, the Council must therefore have regard to whether it would be uneconomic to develop either new or existing pipelines to provide the services of the MSP Mainline and Canberra Lateral.

Uneconomic

6.7 The Tribunal explained the concept of uneconomic as follows:

> *… if a single pipeline can meet market demand at less cost (after taking into account productive, allocative and dynamic effects) than two or more pipelines, it would be "uneconomic", in terms of criterion (b), to develop another pipeline to provide the same services.* (*Duke EGP decision 2001*, paragraph 64)

6.8 The Tribunal cast the test for whether it was uneconomic to develop another pipeline "in terms of costs and benefits to the community as a whole" (*Duke EGP decision 2001*, paragraph 137). By emphasising efficiency "in terms of costs and benefits to the community as a whole", the Tribunal endorsed a 'social' approach to the assessment of whether development of another pipeline was uneconomic.[61] This approach follows from that adopted by the Tribunal in the *Sydney Airport decision*.[62]

6.9 The social approach to the test therefore takes account of all relevant costs and benefits faced by society rather than being limited to private costs and benefits faced by the party considering development of another pipeline. The Tribunal has explained the rationale for this approach as follows:

> *…the uneconomical to develop test should be construed in terms of the associated costs and benefits of development for society as a whole. Such an interpretation is consistent with the underlying intent of the legislation, as expressed in the Second Reading Speech of the Competition Policy Reform Bill [which inserted Part IIIA into the Trade Practices Act 1974], which is directed at securing access to "certain essential facilities of national significance". This language and these concepts are repeated in the statute. This language does not suggest that the intention is*

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61 The Tribunal in the *Duke EGP decision* later confirmed its social costs approach to criterion (b) when it concluded that the Eastern Gas Pipeline met criterion (b) "because it would be uneconomic in a social costs sense to develop [another pipeline] to provide the services provided by means of the [Eastern Gas Pipeline]" (*Duke Eastern Gas Pipeline case*, paragraph 144).

62 The *Sydney Airport decision* was concerned with interpretation of the term "uneconomical" in the declaration criterion in Part IIIA of the Trade Practices Act. The Tribunal in the Duke Eastern Gas Pipeline case stated that nothing turned on the difference between the term "uneconomic" in criterion (b) and the term "uneconomical" in Part IIIA of the Trade Practices Act (*Duke Eastern Gas Pipeline case*, paragraph 58).

> *only to consider a narrow accounting view of "uneconomic" or simply issues of profitability.*
>
> *... If "uneconomical" is interpreted in a private sense then the practical effect would often be to frustrate the underlying intent of the Act. This is because economies of scope may allow an incumbent, seeking to deny access to a potential entrant, to develop another facility while raising an insuperable barrier to entry to new players (a defining feature of a bottleneck). The use of the calculus of social cost benefit, however, ameliorates this problem by ensuring the total costs and benefits of developing another facility are brought to account. This view is given added weight by Professor Williams' evidence of the perverse impact, in terms of efficient resource allocation, of adopting the narrow view.* (Sydney Airport decision 2000, paragraphs 204 - 205)

6.10 Ordover and Lehr provide guidance on how the social interpretation of 'uneconomic' relates to the EAPL applications:

> *When [criterion (b)] is met, the total cost of transporting gas is minimized (and the goal of economic efficiency is served) when the activity is undertaken by one firm rather than by two or more firms. In the instant case, firms demanding transportation of natural gas between the production fields in Cooper Basin and the retail markets in NSW/ACT could not efficiently develop another pipeline that could compete with MSP without the overall cost of gas transport increasing. Such wasteful duplication of assets would engender inefficiencies to the detriment of the consuming public. Therefore, when criterion (b) is satisfied, it is efficient for firms wishing to ship gas between Cooper Basin and the NSW/ACT retail markets to avail themselves of the services provided by the MSP rather than constructing another pipeline. Coverage, if mandated, assures third parties access to the MSP.* (Ordover and Lehr 2001, p.6)

6.11 Noting the findings of the Tribunal and the views of Ordover and Lehr, the Council considers that criterion (b) is satisfied if a single pipeline can satisfy demand for relevant services at lower cost than two or more pipelines. The pipeline is then a natural monopoly[63], and

[63] Ordover and Lehr 2001 provide the following technical description of "natural monopoly" at p.4: Formally, a provision of a particular product or service is a natural monopoly if, over the entire relevant range of outputs, the firms' cost function is subadditive. A cost function C(q) is subadditive at q if it is always cheaper to produce a vector of outputs, q, in a single firm then by partitioning the output among two or more firms. For further discussion of these technical characteristics, see Sharkey, William, *The Theory of Natural Monopoly*, Cambridge University Press: Cambridge, (1982) and W J Baumol, J C Panzar, and R D Willig, *Contestable Markets and the Theory of Industry Structure*, HBJ Publishers: New York (1982).

competition between two or more pipelines offering the same services would be inefficient (Ordover and Lehr 2001, p.4).

Services provided by means of the pipelines

6.12 The test in criterion (b) is whether it is economic to develop another pipeline to provide the services of the MSP Mainline and the Canberra Lateral. Use of the word 'pipeline' excludes from consideration facilities other than pipelines that could provide the services of the MSP Mainline and the Canberra Lateral.

6.13 Consistent with the Tribunal's approach to defining "service" in the *Duke EGP decision* (see paragraphs 5.20 to 5.22), the services of the MSP Mainline and Canberra Lateral are the transport of natural gas from the production fields in the Cooper Basin to gas sales markets in NSW and the ACT. In particular:

(a) the *MSP Mainline* provides natural gas transport services from Moomba to Wilton (Sydney) as well as to points in between including the exit flanges for various laterals along the length of the MSP Mainline (such as the Canberra Lateral)[64]; and

(b) the *Canberra Lateral* provides natural gas transport services from Dalton (the relevant exit flange on the MSP Mainline) to North Watson in the Australian Capital Territory as well as to points in between.

6.14 In determining whether another pipeline could be developed to provide the services of the MSP Mainline and the Canberra Lateral, the other pipeline must be capable of providing gas transportation services from the same start point to the same end points as these pipelines. Pipelines that emanate from the same starting point but travel to other end points, and pipelines that start from other start points but travel to the same end point are not relevant for the purposes of criterion (b).

64 The MSP Mainline also provides part of a natural gas transport service from Longford (Bass Strait) to Sydney, incorporating the following pipelines: the Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline. That part of the service provided by the MSP Mainline is between Young and Sydney. The relevant volumes are about 3% of all gas shipped on the Moomba to Sydney Pipeline System in 2002, forecast to rise to about 16% in 2010 (ACCC 2000b, p.91, Table 2.24).

6.15 For another pipeline to provide the services of the MSP Mainline and Canberra Lateral, the pipeline would therefore have to transport natural gas between the Cooper Basin fields and gas sales markets in NSW and the ACT. No other pipelines currently provide the point-to-point transport services of the MSP Mainline or the Canberra Lateral

6.16 Neither the Interconnect nor the EGP are capable of being developed to provide the services of the MSP Mainline or Canberra Lateral because those pipelines do not accommodate the physical transport of gas between Moomba and Sydney. In a similar way, the lateral from the Eastern Gas Pipeline to Canberra does not provide the same point to point service as the Canberra Lateral, as it emanates from a different starting point to the Canberra Lateral.

6.17 Given that no other pipeline currently provides the services of the MSP Mainline or Canberra Lateral, criterion (b) turns on the cost function associated with the provision of the relevant services.

Required range of output

6.18 Whether it is efficient to develop another pipeline to provide the services of the MSP Mainline and Canberra Lateral turns in part on the range of output that must be satisfied. In particular, if the required range of output exceeds the maximum potential capacity of a pipeline, new entry may be efficient.

6.19 In determining the relevant range of output in the *Duke EGP decision*, the Tribunal focussed on the likely range of reasonably foreseeable demand for the services of the Eastern Gas Pipeline:

> *... the "test is whether for a likely range of reasonably foreseeable demand for the services provided by means of the pipeline, it would be more efficient, in terms of costs and benefits to the community as a whole, for one pipeline to provide those services rather than more than one".* (Duke EGP decision 2001, paragraph 137).

6.20 In the *Duke EGP decision*, the relevant range of output for determining whether the EGP is a natural monopoly was the forecast range of demand for the transport of gas from the Gippsland basin to NSW/ACT over the next 10 – 15 years. (*Duke EGP decision 2001*, paragraph 138). It is this range of demand that would require the services of the EGP or a pipeline providing the same service. In determining the relevant quantum, the Tribunal considered forecast gas demand in NSW/ACT over that period, and the share of that demand likely to be sourced from the Gippsland Basin.

6.21 Consistent with the Tribunal's approach, the relevant range of output for assessing whether the MSP Mainline and Canberra Lateral are natural monopolies in the provision of services between the Cooper Basin fields and NSW/ACT is the maximum foreseeable demand for relevant services over the next 10 – 15 years.

Characteristics of the pipelines

6.22 The MSP Mainline and the Canberra Lateral are transmission pipelines. Whether it is economic to develop new transmission pipelines to provide the services of the pipelines depends on:

(a) whether the pipelines have spare or developable capacity;

(b) whether current and projected levels of demand can be met at lower cost by the existing pipelines or by new pipelines;

(c) whether average production costs per unit of output for the pipelines decline over the range of foreseeable demand;

(d) whether the costs of developing other pipelines to provide the transport capacity sought by third parties outweigh the costs of expanding the capacity of each of the two pipelines to meet that demand (while ensuring the owner/operator and existing users do not lose amenity); and

(e) the height of barriers to entry (such as large upfront costs of developing other pipelines, particularly costs that could not be recovered if a new investment was abandoned).

6.23 The Council notes that gas transmission pipelines typically exhibit natural monopoly characteristics. This is because the costs of constructing and operating a pipeline are largely sunk and fixed, while the variable costs of increasing output are relatively small (Ordover and Lehr 2001, pp.5, 23). Therefore, the marginal cost of transporting a unit of gas is very low. These characteristics mean that the average cost of transporting an additional unit of gas normally declines until the fully expanded capacity of a pipeline is reached. In other words, it is almost always cheaper to transport gas through an existing pipeline (up to the point of full developable capacity) than to build a new pipeline to transport gas along the same route.

6.24 Moreover, the high sunk costs of constructing additional pipelines serves as a barrier to the entry of new pipelines. 'Sunk costs' are those elements of an investment that are fixed or committed, and where, if the investment fails, little or none of the investment can be recovered. The presence of sunk costs also means that incremental or gradual entry – a common form of entry in other industries – is not feasible in gas transmission services.

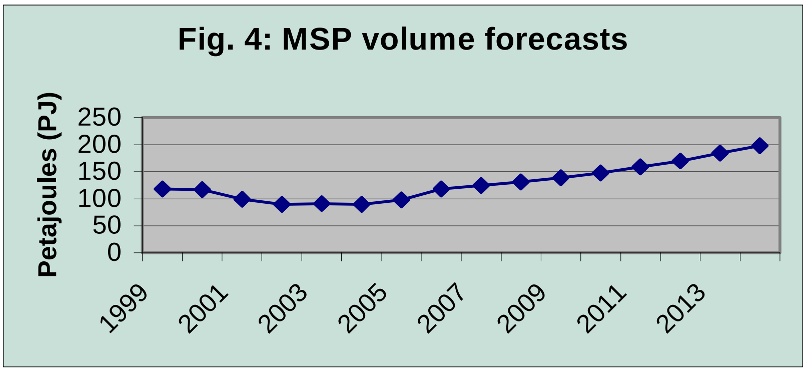
6.25 The Council has not seen evidence to suggest that the MSP Mainline and Canberra Lateral do not exhibit these cost characteristics.

Applying criterion (b) to the pipelines

6.26 Given that the average cost of services provided by the MSP Mainline and Canberra Lateral is likely to decline until the point where maximum potential capacity is reached, the Council accepts that criterion (b) would be satisfied if it can be shown that the maximum potential capacity of the pipelines exceeds the maximum foreseeable demand for relevant services.

MSP Mainline

6.27 The Council has taken guidance on demand for MSP Mainline services from EAPL forecasts supplied as part of the ACCC's regulatory process on the Moomba to Sydney Pipeline System (see Figure.4). Forecast demand ranges from about 90 – 100PJ/a in 2001 – 2005 with steady increases thereafter to around 150 PJ/a in 2010 and 200 PJ/a in 2015 (ACCC 2000b, p.91).[65] The ACCC has accepted these forecasts (ACCC 2000b, p.101).



Source: EAPL 1999a, p.13; ACCC 2000b, p.91.

6.28 The Council accepts from these forecasts that the maximum foreseeable demand for MSP Mainline services over the next 10 –15 years is about 200 PJ per year. In assessing whether it is uneconomic to develop another pipeline to provide the services of the MSP Mainline, it is therefore necessary to consider production economies over output levels required to satisfy this demand.

6.29 EAPL has informed the Council that the MSP Mainline could be expanded from its current capacity of 172 PJ/a to around 290 PJ/a through the installation of six additional compressors. EAPL has stated that "further capacity could be provided through looping" (EAPL 2001, sub.13, p.2). The Council accepts, from this evidence, that the maximum potential capacity of the MSP Mainline is at least 290 PJ/a.

6.30 It has not been proposed by any party that development of another pipeline between Moomba to Sydney could add capacity up to 290

65 These forecasts include carriage of Victorian gas via the Interconnect and MSP Mainline.

PJ/a at lower cost than expansion of the MSP Mainline. Given the cost characteristics of gas pipelines noted above, the Council accepts that the MSP Mainline exhibits declining costs up to 290 PJ/a, and that it would be uneconomic to develop another pipeline to provide the services of the MSP Mainline up to at least 290 PJ/a.

6.31 The Council notes that the maximum potential capacity of the MSP Mainline (at least 290 PJ/a) exceeds the maximum potential demand for the services of the pipeline (about 200 PJ/a) over the next 10 –15 years. The economics of pipeline construction would suggest that building two (or more) point-to-point pipelines, each carrying only a share of these forecast volumes would be uneconomic. Given the current and anticipated state of demand, it is therefore reasonable to conclude, on cost criteria alone, that the MSP Mainline is a natural monopoly in the provision of transport services for natural gas between Moomba and Sydney (Ordover and Lehr 2001, p.5).

6.32 Ordover and Lehr point out that this conclusion is reinforced by considering the capacity of the Moomba to Sydney Pipeline System in relation to gas demand in NSW/ACT, and gas reserves in the Cooper Basin. While the cost characteristics of the production function over the range of foreseeable demand are the essential test for natural monopoly, Ordover and Lehr argue that this conclusion is reinforced by the fact that the MSP Mainline has substantial excess capacity, and that there are insufficient gas reserves in the Cooper Basin to warrant construction of another pipeline:

> *... these data indicate that the MSP is likely to be able to meet the relevant retail demand in NSW and the ACT retail markets and that the Cooper Basin reserves are not so large as to warrant construction of a second pipeline during the expected remaining lifetime of the MSP. To the extent that the MSP has excess capacity today or is likely to have excess capacity in the future, the costs of serving the forecasted gas demand by two or more pipelines would be even higher.* (Ordover and Lehr 2001, p.6)

6.33 In view of the expandable capacity of the MSP Mainline and the relatively modest costs of expansion compared to the costs of developing another pipeline; and the forecast demand for MSP Mainline services in the next 10 – 15 years, the Council concludes that it would not be economic to develop another pipeline to provide the services of the MSP Mainline.

Canberra Lateral

6.34 The Canberra Lateral has a current capacity of around 16.8 PJ/a (EAPL 1999b, p.32). In 1999, EAPL reported that 16.4 PJ/a was contracted. It was also forecast that peak day demand would outstrip capacity in 2001, and would rise to 18.2 PJ/a in 2005 (EAPL 1999b, p.32).

6.35 In 1999 EAPL proposed expanding the capacity of the Canberra Lateral to cope with rising demand through partial looping, at a cost of around $3.458 million (EAPL 1999b, p.33). This would increase capacity to 21.2 PJ/a (EAPL 1999b, p.34).[66] This equates with an incremental cost to expand the Canberra Lateral of less than $800,000 per PJ/a in additional capacity. On EAPL's forecast volumes, this capacity expansion would have satisfied 2005 peak day demand with some spare capacity.

6.36 The Council notes that the proposed capacity expansion of the Canberra Lateral is within the maximum expandable capacity of the pipeline. It has not been proposed by any party that development of another pipeline between Dalton to Canberra could add capacity up to 21.2 PJ/a at lower cost than expansion of the Canberra Lateral. Given the cost characteristics of gas pipelines noted at paragraphs 6.23 to 6.25, the Council accepts that the Canberra Lateral is likely to exhibit declining costs over the range of output up to at least 21.2 PJ/a and that it would be uneconomic to develop another pipeline to provide the services of the Canberra Lateral up to at least 21.2 PJ/a.

6.37 The Council notes that proposed expanded capacity of the Canberra Lateral (21.2 PJ/a) exceeds forecast 2005 peak day demand. The economics of pipeline construction would suggest that building two (or more) point-to-point pipelines, each carrying only a share of these forecast volumes would be uneconomic. Given the current and anticipated state of demand, it is therefore reasonable to conclude, on cost criteria alone, that the Canberra Lateral is a natural monopoly in the provision of transport services for natural gas between Dalton and Canberra.

6.38 In view of the expandable capacity of the Canberra Lateral and the relatively modest costs of expansion compared to the costs of developing another pipeline; and the forecast demand for relevant

[66] Reported as lifting capacity from 46 TJ/d to 58 TJ/d: EAPL 1999b, p. 34.

services in 2005, the Council concludes that it would not be economic to develop another pipeline to provide the services of the Canberra Lateral.

Conclusion on criterion (b)

6.39 The Council concludes that it would not be economic to develop pipelines to provide the services of the MSP Mainline and the Canberra Lateral at current and reasonably foreseeable levels of future demand. This conclusion follows from the finding of declining average production costs over the range of reasonably foreseeable demand for the services of the pipelines.

6.40 The Council therefore finds that the MSP Mainline and Canberra Lateral satisfy criterion (b).

7 Criterion (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

The Council's approach to criterion (a)

7.1 Criterion (a) specifies that coverage is only warranted if regulated access would create the conditions or environment for improving competition in at least one market other than the market for the services of the gas pipeline.

7.2 To conclude that a pipeline meets criterion (a), the Council must be satisfied that:

(a) the service to which access is sought is not in the same market as the market or markets in which competition is promoted; and

(b) access would promote a more competitive environment in that other market.

Market delineation

7.3 There are a number of potential markets that may be affected by a decision to revoke coverage of the MSP Mainline and Canberra Lateral (**MSP**[67]); in particular, the markets encompassing the activities of gas exploration, production, processing, reticulation, wholesaling and retailing.

[67] The MSP Mainline and Canberra Laterals are separate pipelines for the purposes of this report, and the Council makes separate recommendations for each. For the sake of brevity, the abbreviation 'MSP' is used in section 7 of this report to jointly refer to the MSP Mainline and Canberra Lateral. The Council notes that the Moomba to Sydney Pipeline System encompasses a number of other laterals that are not subject to the current revocation application. For information on the Moomba to Sydney Pipeline System, see paragraphs 3.2 – 3.10 and 4.46 – 4.54. For specification of the pipelines subject to the current revocation applications, see paragraph 3.4.

7.4 The Council has focussed its consideration on the market or markets in which gas sales take place. In defining the scope of such market(s), the Council has considered:

(a) the product dimension; in particular, whether relevant markets are for natural gas sales or for energy sales;

(b) different functional levels across markets in which sales of natural gas occur;

(c) the geographical boundaries of relevant markets; and

(d) the temporal dimensions of relevant markets.

7.5 The Council provides a generic discussion of these market dimensions in paragraphs 5.23 to 5.32 of this report.

7.6 Below, the Council considers the relevant market dimensions with respect to the MSP revocation applications.

Product dimension

7.7 An issue for the Council is whether sales of natural gas occur in a market for natural gas only, or in a wider product market encompassing other forms of energy, such as electricity.

7.8 In the *AGL Cooper Basin supply arrangements decision*, the Tribunal examined the extent of substitution between electricity and gas in delineating the relevant product market for natural gas. The Tribunal concluded that gas and electricity were not substitutes (though to some extent, demand for gas related to demand for electricity) and that a separate natural gas market existed with competition from other forms of energy at the margins:

> *We find that there are three product markets of relevance for this application. The first is natural gas, extending at the margin to encompass, at times, alternative and complementary energy sources, principally electricity. When we refer to the "natural gas market", it should be understood in this extended sense. Then there are two further product markets, the services of transmission and reticulation.* [(1997) ATPR 411-593 at pp. 44210-44211]

7.9 The Council considered the extent of convergence between gas and electricity markets in its recommendation on an application for coverage of the Eastern Gas Pipeline (**EGP**). In particular, the Council took into account submissions from a number of parties as well as evidence on the cross-price elasticity of demand between gas and electricity.[68] Submissions by Network Economics Consulting Group (**NECG**), the Law and Economics Consulting Group (**LECG**), the Australian Pipeline Industry Association (**APIA**) and Incitec addressed this issue. APIA's submission argued that gas and electricity markets were rapidly moving towards convergence within an energy market, while the submissions of LECG and NECG suggested that while the markets may not have converged, electricity prices significantly constrain the pricing of gas transmission tariffs.

7.10 In the *Duke EGP decision*, the Tribunal said:

> *There were virtually no differences in the submissions and economic evidence about the definition of the two relevant markets, which drew on the Tribunal's market determination in [the AGL Cooper Basin supply arrangements decision] to some extent. It was agreed that the product of concern is mainly gas as there is little competition between energy sources at this time* (Duke EGP decision 2001, paragraph 77).

7.11 The relevant product market for the purposes of criterion (a) is therefore the market or markets for natural gas.

Functional dimension

7.12 In the *AGL Cooper Basin supply arrangements case*, the Tribunal found that there were a number of functional levels to be considered in defining the natural gas market: exploration, production and processing and distribution [(1997) ATPR 41-593 at p. 44211]. In using the term 'distribution' in this context the Tribunal seems to be referring to the sale of gas to end users, rather than reticulation services (the carriage of gas through distribution pipelines).

7.13 The Tribunal developed this approach in the *Duke EGP decision*, where it identified different functional levels in natural gas markets. In that case, it was accepted that gas transmission services are provided in functionally distinct markets from other services:

> *It was agreed that gas transmission services are provided in the gas transmission market which is functionally separate from other parts of the gas market. Other functional areas are exploration, production/ processing, sales and distribution/ reticulation.* (Duke EGP decision 2001, paragraph 77).

68 For an explanation of cross-price elasticity of demand see Ordover and Lehr 2001, p.9, footnotes 19 and 20 and related discussion.

7.14 The Tribunal, in the *Duke EGP decision*, identified relevant “other” markets for the purposes of criterion (a) as:

(a) a downstream market, being the sale of gas to users in South East Australia; and

(b) an upstream market, being the production of gas, which would imply competition between the Cooper Basin and Gippsland Basin producers (*Duke EGP decision 2001, paragraph 80).*

7.15 Similarly, Ordover and Lehr identify functional markets for gas sales that are separate from the market for gas transmission services. The markets are upstream and downstream of the pipeline, which “connects” the gas sales markets (Ordover & Lehr 2001, p. 9,11). Ordover and Lehr consider that:

(a) the upstream gas sales market encapsulates transactions between gas producers within the gas field served by the pipeline in question, and parties able to buy gas directly from that gas field. Buyers could include the owner of gas transmission pipelines serving the gas field[69], gas wholesalers and distributors, retailers, aggregators and perhaps major users. Thus, the upstream market comprises the field of gas buyers available to gas producers in a particular gas field. Clearly, buyers of gas at the upstream end also require pipeline services to transport the gas to customers. Absent application of the National Gas Code, a single pipeline serving a gas field, whose owner declined to provide access to buyers of gas, would constitute a monopsony in the upstream gas market; and

(b) downstream gas sales markets comprise transactions between gas sellers (which may include gas producers, owners of gas transmission pipelines[70], gas wholesalers and distributors, retailers, aggregators and perhaps major users) and end users of natural gas. Sellers of gas at the downstream end also require pipeline services to transport the gas to end consumers. Absent application of the National Gas Code, a single pipeline delivering into a gas

69 Absent application of the National Gas Code.

70 Absent application of the National Gas Code.

sales market, whose owner declined to provide access to gas sellers, would constitute a monopoly seller in the downstream gas market.

7.16 Ordover and Lehr adopt the approach taken by the Tribunal in the *Duke EGP decision* and the *AGL Cooper Basin supply arrangements decision* in identifying relevant upstream and downstream markets as being markets for gas sales. In the Ordover and Lehr model, however, upstream competition refers to rivalrous behaviour between gas producers within a particular gas field to supply potential buyers in that field. The Tribunal's reference to upstream competition between gas fields (*Duke EGP decision*, paragraph 80) is encapsulated in the Ordover and Lehr concept of downstream competition.

7.17 Implicit in the Ordover and Lehr framework is the notion that the pipeline owner may be a buyer of gas upstream and a seller of gas downstream.[71] Third party use of the pipeline enables other parties to also buy gas from upstream producers and sell gas to downstream retailers and users.

7.18 There is a question whether further functional market delineations should be made, such as a distinction between wholesale and retail gas sales. While there is some evidence to suggest that wholesale supply and retail supply are economically separable it is more difficult to determine whether they are economically distinct. Whether there is a further delineation of separate retail and wholesale markets is not material to any issues arising in this application and is not considered further.

Geographic dimension

(a) Upstream

7.19 The geographic boundary of the upstream gas sales market is delineated by the producers served by the pipeline in question; that is, gas producers within a particular gas field or within the scope of feasible interconnection with the pipeline. For the MSP, the

71 While the ring fencing provisions of the National Gas Code do not permit a covered pipeline to buy and sell gas, there would be no restriction on a non-covered pipeline from doing so.

geographic dimension of the upstream gas sales market is the Cooper Basin.

(b) Downstream

7.20 Delineating the geographic boundaries of downstream gas sales markets is more complex than for the upstream gas sales market.

7.21 Currently, sales gas transmission pipelines connect the Moomba processing plant to Adelaide, Sydney, Canberra, Melbourne and various NSW and Victorian regional centres.

7.22 The Longford plant, which processes Bass Strait gas, is connected by sales gas transmission pipelines to Melbourne, regional Victoria, Sydney, regional NSW, and Canberra. With the completion of the EGP, Longford is also connected to areas of regional Victoria and NSW.

7.23 Completion of the Interconnect in 1998 enabled the Gippsland Basin producers to offer a limited amount of gas to the Sydney, Canberra and regional NSW areas, in competition with the Cooper Basin producers. Completion of the EGP has expanded this potential.

7.24 In the AGL Cooper Basin supply arrangements decision, the Tribunal said:

> *The geographic dimension of the natural gas market has been expanding from NSW in 1986 to south-east Australia (NSW, Victoria, South Australia and Southern Queensland) today. In the "future market" it will be Australia-wide, including off-shore sources of gas in West Australia and the Northern Territory, and also possibly Papua New Guinea.* [(1997) ATPR 41-593 at p. 44211]

7.25 The Tribunal adopted this view because the development of new pipelines linking, eventually, all gas production fields with all gas users would mean that any gas user could buy gas (directly or indirectly) from any gas producer, thus integrating the fields of rivalry for gas sales, at least from the user (downstream) perspective.

7.26 Similarly, in the *Duke EGP decision*, the Tribunal said:

> *It was agreed that the geographic scope of the market is South East Australia. There was a slight difference in the economic evidence on the geographic scope of the South East Australia market but it was agreed that the difference was not material to*

> *the assessment of criterion (a)* (Duke EGP decision 2001, paragraph 77).

7.27 However, as the Tribunal recognised in its discussion of regional markets, the extent of downstream competition varies in different regions of south-east Australia (*Duke EGP decision 2001*, paragraphs 80, 83, 125-133). The Tribunal noted that the EGP serves several regions south of Canberra with characteristics distinct from the Canberra and Sydney markets:

> *Separate consideration needs to be given to the position in regional centres south of the ACT as these areas are not served, and are not likely to be served, by a pipeline other than the EGP* (Duke EGP decision 2001, paragraph 83).

7.28 The Council notes that some parts of south-east Australia have no access to gas; while much of western NSW and most of Victoria have access to gas from one gas producer or one gas field. Other regions, such as Sydney and Canberra, have access to gas from two distinct sources. While it is feasible that future pipeline development may eliminate barriers to entry in gas marketing and integrate the field rivalry in gas retailing within south-east Australia, or even the whole of Australia, the Council does not consider that this reflects the current situation.

7.29 Ordover and Lehr reach a view consistent with the Tribunal's comments on regional variations:

> *Identifying the appropriate downstream retail market or markets, is more complex than for the upstream market since it is possible that the downstream market may be effectively segmented either on the basis of end-user location or customer type. If this is the case, then it may not be possible to treat the NSW/ACT as a single market, but rather as a collection of separate geographic or customer markets. For example, some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from coverage if it leads to lower transport prices and assured access to the pipeline...* (Ordover and Lehr 2001, p.18).

7.30 The issue of market segmentation takes on particular significance if the MSP can charge differential prices to different categories of buyers located in different areas. The Council observes that the MSP claims to offer non-discriminatory tariffs. However, absent coverage, there would be no constraint on price discrimination being practised between regions. The ability to engage in successful price discrimination requires that gas buyers be constrained from engaging in secondary trading. The potential for secondary trading arises if customers are interconnected by a common gas distribution network – especially one regulated by the National Gas Code – and where customers can therefore nominate preferred offtake points.

7.31 In the absence of an interconnected distribution network, opportunities for price discrimination are likely to be more potent. Thus, there may be opportunities to engage in price discrimination between customers in Sydney and Canberra, for example. The Council notes that EAPL's 1999 access arrangement for the MSP proposed that Moomba to Sydney tariffs be reduced by about 6% from 2001-2005, but that tariffs to Canberra rise by about 35% over the same period (ACCC 2000b, p.119).[72]

7.32 The Council therefore considers that there may be significant differences in market conditions between different regions of NSW/ACT. The Council concludes that Sydney and Canberra each comprise separate gas sales markets. In addition, other downstream markets exist along the length of the MSP.

Temporal dimension

7.33 The dimensions of gas sales markets evolve over time. For example, product delineation between gas and electricity appears to be weakening over time.

7.34 The temporal dimension of a market must allow scope for substitution in demand and supply. In doing so, the focus is not on a "short-run transitory situation"[73] but on the substitution possibilities which are available in the foreseeable future. It is important in this regard to distinguish between supply side substitution possibilities and new entry. As the ACCC has noted in its Revised Merger Guidelines:

> *Where substitution requires significant new investment by producers or consumers, these sources of competition will not be*

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72 The ACCC draft decision on the MSP access arrangement found that the Canberra tariffs reflected an over-recovery of stand-alone costs and proposed that the MSP Mainline tariff be applied to the Canberra Lateral (ACCC 2000b, p108-109, 118). In 2002, EAPL proposed amended tariffs.

73 Re *Tooth &Co Ltd; In re Tooheys Ltd* (1979) ATPR 40-113 at 18,196.

> *included in the relevant market but will be considered under market entry.* (ACCC 1999, paragraph 5.75)

7.35 In the context of gas markets, a decision to construct a new transmission pipeline is likely to affect substitution possibilities for upstream producers and downstream gas customers. For example, a new pipeline may affect the geographic dimensions of the relevant market. However, such prospective new entry will not be included within the scope of the existing market.

Non-gas markets

7.36 While the Council focuses its consideration on the promotion of competition in gas sales markets, the Council has also considered arguments raised by some parties that access to the MSP may promote competition in export and import-competing industries where gas is a production input. The argument is based on the premise that a reduction in gas transportation costs would improve the competitive position of firms operating in export and import-competing industries.

7.37 According to BHP Billiton and Incitec:

> *Any form of licensing or other barrier to entry amounts to a licence to impose what are essentially taxes on other businesses and consumers. As with all taxes, some businesses will be able to pass on these burdens but others will not. The net result is that competition will be diminished. At the extreme, Australian exporters who face increased input costs from monopoly rents demanded as part of input prices and are unable to pass on such monopoly rents costs in internationally competitive markets are driven out of business. Similarly, Australian producers may not be able to compete effectively with imports* (BHP Billiton and Incitec 2002, sub.23, p.8).

7.38 EAPL argues that this position confuses the concept of “promotion of competition” with promoting competitiveness:

> *Competition is a distinctly different concept from competitiveness. An increase or decrease in the competitiveness of a particular competitor or group of competitors in a market does not necessarily increase, reduce or have any effect at all on the opportunities and environment for competition in that market.*
>
> *As a rule, world markets can draw from a large pool of potential entrants, and it would be unusual for any one player’s entry or exit to make a material difference to the ability of competition in*

> *such a market to deliver benefits to consumers. Indeed, the paper recognizes and admits this when it notes that "for most products traded internationally, Australia is a price taker" and hence by definition cannot have any impact on the extent of competition. However, it is the impact on competition that must be tested under criterion (a).* (EAPL 2002, sub.25, p.2).

7.39 The Council accepts that inefficient transportation tariffs can adversely affect export and import-competing industries that rely on gas as a production input.

7.40 However, the "promotion of competition" test should not be assessed in terms of the effect on particular competitors. Rather, criterion (a) focuses on the impact of coverage on the broad competitive environment in the dependent market (*Sydney Airport decision 2000*, paragraph 106). If the dependent market is already effectively competitive, it would be difficult to argue that regulated access would improve the competitive environment. The Council accepts that Australia's export and import-competing industries tend to be exposed to a competitive international environment. In this sense, while regulated access may improve the competitiveness of particular Australian firms, it is not apparent that coverage would enhance the broader competitive environment in the markets in which those firms operate.

Conclusions on market delineation

7.41 Having regard to the Tribunal's approach in the *AGL Cooper Basin supply arrangements decision* and the *Duke EGP decision*, and the Ordover and Lehr framework, the Council has identified the following relevant markets as being separate from the market in which gas transmission services are provided:

(a) the upstream gas sales market for gas produced in the Cooper Basin;

(b) downstream gas sales markets along the route of the MSP Mainline and the Canberra Lateral ; and

(c) downstream gas sales markets for Sydney and Canberra.

7.42 Criterion (a) requires consideration of whether access (or increased) access to MSP services would promote competition in one or more of these markets.

Promotion of competition

7.43 Criterion (a) requires consideration of whether regulated access under the National Third Party Access Code for Natural Gas Pipeline Systems (**National Gas Code**) would promote competition in a dependent market.

7.44 The notion of competition is central to Australian trade practices law. Competition is a dynamic process, generated by market pressure from alternative sources of supply and demand. In this sense, competition expresses itself as rivalrous market behaviour. The key feature of effective competition is that no one seller (or group of sellers) or buyer (or group of buyers) has sustained and substantial market power.

7.45 The Federal Court, in the QCMA decision, described "competition" as follows:

> *"Competition expresses itself as rivalrous market behaviour … In our view effective competition requires both that prices should be flexible, reflecting the forces of demand and supply, and that there should be independent rivalry in all dimensions of the price-product-service packages offered to consumers and customers.*
>
> *Competition is a process rather than a situation. Nevertheless whether firms compete is very much a matter of the structure of the markets in which they operate.* (Re Queensland Co-operative Milling Association Ltd; Re Defiance Holdings Limited (1976) 25 FLR 169,188).

7.46 Promotion of competition refers to improving the opportunities and environment for competition such that competitive outcomes are more likely to occur. In considering s.44H(4)(a) of the TPA, on which criterion (a) of the National Gas Code is based, the Tribunal in the *Sydney Airport decision* made the following observations on the promotion of competition test:

> *The Tribunal does not consider that the notion of "promoting" competition in s 44H(4)(a) requires it to be satisfied that there would be an advance in competition in the sense that competition would be increased. Rather, the Tribunal considers that the notion of "promoting" competition in s 44H(4)(a) involves the idea of creating the conditions or environment for improving competition from what it would be otherwise. That is to say, the opportunities and environment for competition given declaration, will be better than they would be without declaration.*

> *We have reached this conclusion having had regard, in particular, to the two stage process of the Part IIIA access regime. The purpose of an access declaration is to unlock a bottleneck so that competition can be promoted in a market other than the market for the service. The emphasis is on "access", which leads us to the view that [section] 44H(4)(a) is concerned with the fostering of competition, that is to say it is concerned with the removal of barriers to entry which inhibit the opportunity for competition in the relevant downstream market. It is in this sense that the Tribunal considers that the promotion of competition involves a consideration that if the conditions or environment for improving competition are enhanced, then there is a likelihood of increased competition that is not trivial.* (Sydney Airport decision 2000, paragraphs 106 - 107)

7.47 The Tribunal added:

> *The Tribunal is concerned with furthering competition in a forward looking way, not furthering a particular type or number of competitors. In this matter, therefore, the Tribunal must be reasonably satisfied that declaration would, looking forward, improve on the competitive conditions in the relevant markets that are likely to exist as a result of the [Sydney Airports Corporation Limited] tender process as compared with a situation where there was no declaration.* (Sydney Airport decision 2000, paragraph 108)

7.48 The Tribunal in the *Duke EGP decision* endorsed this approach:

> *The Tribunal* [in the Sydney Airport decision 2000] *concluded that the TPA analogue of criterion (a) is concerned with the removal of barriers to entry which inhibit the opportunity for competition in the relevant downstream market. It is in this sense that the notion of promotion of competition involves a consideration that if the conditions or environment for improving competition are enhanced, then there is a likelihood of increased competition that is not trivial. We agree.* (Duke EGP decision 2001, paragraph 75).

7.49 Consistent with the Tribunal's findings, the Council concludes that "promotion of competition" refers to improving the environment or conditions for competition. This may, for example, involve removing barriers to entry that inhibit opportunities for competition. Similarly, it may involve removing barriers that limit the ability of small players to expand their level of operations within a market.

Temporal considerations

7.50 Criterion (a) assesses whether coverage would promote the environment for competition in at least one dependent market, compared with conditions absent coverage.

7.51 It is not necessary to establish that more competitive outcomes will actually occur, or will occur within a particular period of time. This reflects that there may be a substantial lead time between a change in the competitive environment and the ability of new entrants to undertake investment. As Ordover and Lehr point out, the emergence of new entry may be a gradual process:

> *Because of other market frictions, entry may be slow in coming. Hence, criterion (a) cannot be taken to mean that coverage would rapidly induce entry relative to the no-coverage benchmark. Rather, we take the criterion to mean that coverage is justified if imposition substantially increases the overall competitive conditions in relevant market(s), including the likelihood of entry. Here, it is important to point out that the mere reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers (which includes price, conditions of sale, service, and so on)* (Ordover and Lehr 2001, p.11).

7.52 Notwithstanding that new entry may be slow in coming, criterion (a) requires that more competitive outcomes, looking forward, are likely. This requires consideration of future events and market conditions, including:

(a) likely competitive conditions in dependent markets, looking forward; and

(b) exogenous events that may affect the competitive environment in the future.

7.53 Time horizons may be of particular relevance where access is one of a number of barriers to entry. Criterion (a) would then require consideration of whether other barriers are likely to remain in place, looking forward. To satisfy criterion (a), the Council must be satisfied that coverage improves the competitive environment such that a credible threat of entry arises.

7.54 In the *Duke EGP decision*, the Tribunal had regard to the effects of supply and demand conditions over a ten to fifteen year period (*Duke EGP decision 2001*, paragraph 118):

> *In [the AGL Cooper Basin supply arrangements decision] at 44,210, the Tribunal specified a period of "perhaps ten or fifteen years" as the future market. This period appears to be sufficient in this case given the uncertainties surrounding the operation of a competitive market and forecasts of demand, the existence of spare capacity and significant long term contracts which expire in 2006, and the time to develop new pipelines and new gas fields.* (Duke EGP decision 2001, paragraph 78)

7.55 The Council's consideration of the MSP applications has raised a diversity of views as to the appropriate weight that should be attached to future events. For example, in the *Duke EGP decision*, the Tribunal found that the Moomba to Sydney Pipeline System may become an important supply hub in shipping gas from northern Australia and/or Papua New Guinea to NSW markets, possibly by the middle of this decade (*Duke EGP decision 2001*, paragraph 98). The Tribunal considered this relevant to the promotion of competition test (*Duke EGP decision*, paragraphs 102-103). However, NECG expressly excluded consideration of these proposed developments from its analysis of upstream markets, on the grounds that the plans "remain very uncertain" (NECG 2002, sub. 19, App G, p.6, footnote 13). Ordover and Lehr also considered that the proposals were not sufficiently advanced to be taken into account under criterion (a) (Ordover and Lehr 2001, p.6, footnote 12).

7.56 The Council considers that short term and longer term horizons are relevant in considering the possible effects of speculative events on markets. As a general rule, the relevance of a future event to the promotion of competition test should reflect the probability of the event occurring. A consideration here is the forecast timing of the event, but other contingencies may also be relevant.

7.57 Noting the changes occurring in energy and gas sales markets (paragraph 7.9), the Council considers it appropriate to attach principal weight to the likely competitive environment in the next five to ten years. Beyond that horizon, an assessment of the relevant probabilities becomes highly speculative.

Market power

7.58 In the *Duke EGP decision*, the Tribunal found that the ability to exercise market power in a dependent market is a key factor in determining whether coverage would promote competition:

> *Whether competition will be promoted by coverage is critically dependent on whether EGP has power in the market for gas*

> *transmission which could be used to adversely affect competition in the upstream or downstream markets. There is no simple formula or mechanism for determining whether a market participant will have sufficient power to hinder competition. What is required is consideration of industry and market structure followed by a judgment on their effects on the promotion of competition* (Duke EGP decision 2001, paragraph 116).

7.59 Ordover and Lehr describe the economic definition of market power as follows:

> *In economics, market power is defined as the ability to profitably raise prices above marginal cost. Any firm – other than a firm operating in a perfectly competitive market – can have, in principle, some ability to raise price above marginal cost: all that is required is that the firm faces a downward-slopping demand curve. Indeed, under some cost conditions, pricing at marginal cost would ruin the firm and is thus a precondition for financial viability.*[74] *Regulatory concerns arise only if the firm possesses significant and durable market power leading to prices that substantially deviate from proper economic costs and which generate persistent supracompetitive returns. When a firm possesses substantial and durable market power, it is often said to possess "monopoly power." Additionally, a firm with market power may have both an incentive and ability to engage in market strategies designed to protect its monopoly profits and power to the detriment of competition and consumers.*[75] (Ordover and Lehr 2001, p.7)

7.60 The most pervasive constraint on the ability to translate market power into a dependent market is effective competition in that market:

> *The existence of effective competition precludes the ability profitably to exercise monopoly power, and therefore, a finding that effective competition exists in a market is usually taken to be equivalent to a finding that no firm in that market possesses substantial market power. In the presence of effective competition, prices are driven towards economic costs and resources are allocated efficiently* (Ordover and Lehr 2001, p.7).

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74 “For example, marginal cost pricing will fail to recover total costs if there are substantial fixed costs.”

75 “Of course, firms generally strive to protect or enhance their market positions. Such quest for profits and market share is, indeed, an engine of competition and should not be discouraged. See, for example, Jeffrey Church and Roger Ware, *Industrial Organisation*, Irwin/McGraw Hill, Boston (2000).”

7.61 The concept of effective competition recognises that, in the real world, most firms have some discretion over price. Market power garnered through means such as innovation and superior customer service or operating efficiency is consistent with the process of effective competition. If a firm with market power lacks the ability to use that power to harm the competitive process (ie rivalrous behaviour between firms), then that firm does not have a substantial degree of market power. In such circumstances, the market may be considered effectively competitive.

Competition with and without access

7.62 As has been noted, the Tribunal found in the *Sydney Airports decision* that the "promotion of competition" test requires an assessment of whether regulated access would improve the competitive conditions in relevant markets, compared with the conditions likely to exist absent regulation *(Sydney Airport decision 2000, paragraph 108).*

7.63 The Tribunal endorsed this approach in the Duke EGP decision:

> *... the question posed by criterion (a) is whether the creation of the right of access for which the Code provides would promote competition in another market. The enquiry is as to the future with coverage and without coverage. We agree with the approach adopted by the Tribunal in Sydney International Airport in this respect. The Tribunal must have regard to the position as it now stands, insofar as it provides a reliable guide to the future without coverage. Thus, (assuming the present is a reliable guide to the future without) account is to be taken of the EGP as an open access pipeline, and of any other pipelines supplying the upstream or downstream gas markets, in order to determine whether coverage of the EGP would promote competition in at least one of those markets* (Duke EGP decision 2001, paragraph 74).

7.64 In applying the "with and without" test endorsed by the Tribunal in the *Sydney Airport decision* and the *Duke EGP decision*, it is necessary to identify the "with and without" coverage counterfactuals.

7.65 The "with coverage" scenario is the likely market conditions that would exist if access to the MSP was regulated by the ACCC under the National Gas Code. The Code establishes a framework requiring service providers to offer access to spare capacity in pipelines on efficient terms and conditions and disclose pricing information to third parties. The Code also establishes detailed ring fencing parameters, requires regulatory approval of contracts between affiliates, and provides for independent dispute resolution.

7.66 The Council notes that current conditions pertaining to the MSP are a hybrid: some conditions are the result of coverage, while others reflect unregulated conditions. Some conditions may reflect a blend of regulated and unregulated influences.

7.67 The Moomba to Sydney Pipeline System has been a covered pipeline since the commencement of the National Gas Code.[76] In NSW, the enabling legislation (the *Gas Pipelines Access (NSW) Act 1998)* was proclaimed on 14 August 1998.

7.68 The commencement of the Code immediately activated several provisions, including the requirement that a gas pipeline business be ring fenced from other business activities (s.4 of the Code). The AGL group was restructured in the late 1990s. The new corporate structure was consistent with the ring fencing provisions of the Code.[77]

7.69 The Code's commencement also activated provisions on regulatory approval of associate contracts (ss. 7.1-7.6). The terms of the Gas Transportation Deed (**GTD)** between EAPL and AGLWG were approved under these provisions by the ACCC in 2000. The regulatory approval process would not have been required if the MSP was not a covered pipeline. It appears from the ACCC's Statement of Reasons that the approved terms of the GTD were different from those lodged, which contained what the ACCC considered to be price disincentives to third party access (ACCC 2000a).[78]

7.70 Other aspects of current conditions reflect an unregulated world. In particular, several aspects of coverage (including regulated access tariffs) do not apply until an access arrangement is approved under the Code by the regulator. While the ACCC has released a draft

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76 The Moomba to Sydney Pipeline System is listed at Schedule A of the Code. Pipelines listed at Schedule A are automatically covered from the commencement of the Code.

77 Some provisions had also been activated by an interim version of the Code that commenced in NSW in April 1997.

78 It is questionable, however, that AGLWG and EAPL would currently be regarded as associates under the National Gas Code: see confidential Attachment 1 of this report. The GTD was approved by the ACCC under an earlier corporate structure of the AGL group.

decision on an access arrangement for the Moomba to Sydney Pipeline System, tariffs will remain unregulated until a final approval is given. Indeed, the regulator has indicated that current tariffs would require substantial modifications to satisfy the requirements of the Code (ACCC 2000b).

"With coverage"

7.71 Noting the foregoing discussion, the Council observes the following elements of the "with coverage" scenario.

(a) The current corporate structure of the AGL group, APT, EAPL and related bodies is consistent with the ring fencing provisions of the National Gas Code.

(b) The terms and conditions of the Gas Transportation Deed (other than price) have been approved by the ACCC as an associate contract under the Code.

(c) Third parties have a statutory right to negotiate access to spare capacity in the MSP on terms and conditions (including a reference tariff) set out in an access arrangement approved by the ACCC. While the ACCC is yet to approve an access arrangement for the MSP, the ACCC's draft determination on the MSP access arrangement, released in December 2000, provides guidance on access terms and conditions that the regulator may approve in future under the Code.

7.72 The Council notes that the ACCC determination is only a draft, and may be subject to further refinement. As the AGA points out:

> *The use of estimated data from incomplete regulatory processes, and draft conclusions relating to actual and efficient costs produced by the ACCC, as an input into a key threshold decision on the coverage of an asset by a regulatory regime is highly inappropriate. The estimates relied upon by the Council and its external advisers arise from a specific regulatory process that has not been finalised. As estimates made in the specific context of negotiations on access pricing it is inappropriate for the estimates to be used to draw conclusions on the threshold issue of whether access regulation is appropriate for the pipeline* (AGA 2002, sub.17, p.11)

7.73 The Council considers that while a draft determination is open to further refinement, it nonetheless provides the best available indicator of terms and conditions, including tariffs, that would apply under the "with coverage" scenario.

“Without coverage”

7.74 Consistent with the Council’s approach to the “with coverage” scenario, the “without coverage” scenario encapsulates:

(a) the likely corporate structure of the AGL group, APT, EAPL and related bodies absent coverage;

(b) the provisions of the GTD, including possible amendments, absent coverage; and

(c) the terms and conditions of access absent coverage.

7.75 On the first point, the Council notes that absent coverage, the ring fencing requirements of the National Gas Code would no longer apply to the MSP. To the extent that the ring fencing provisions affect the corporate structure of the AGL group at present, this influence would be removed absent coverage. Absent the Code’s regulatory requirements, it would be possible for the AGL group to adopt a vertically integrated ownership structure, subject to Part IV of the *Trade Practices Act 1974*.

7.76 On the second point, the Council notes that the GTD was approved by the ACCC as an associate contract under the National Gas Code. The original terms of the GTD, as proposed by EAPL, contained what the ACCC considered to be price disincentives to third party access:

> *the practical commercial effect of the initial ‘equal best’ pricing provisions would be to discourage EAPL from discounting and to discourage third parties from entering the markets for acquisition of transmission services and retail supply of gas (ACCC 2000a, p.5)*

7.77 There is some contention as to whether AGLWG and EAPL would currently be regarded as associates under the National Gas Code. This matter is discussed in full at Attachment 1 (confidential).

7.78 It is difficult to consider the operability of the GTD absent coverage, **[confidential information]**. Should EAPL and AGLWG agree to terminate the GTD and enter into a new deed, EAPL considers that any new agreement would not require approval by the ACCC under the Associate provisions of the Code (KPMG 2002).

7.79 The Council considers that the provisions of the GTD may continue to apply absent coverage, **[confidential information]**.

7.80 On the third point, the "without coverage" scenario does not provide a statutory right for third parties to negotiate access to spare capacity in the MSP on terms and conditions set out in an access arrangement approved by the ACCC. Instead, the terms and conditions of access would be determined at the discretion of EAPL, the pipeline owner.

7.81 As the Council has noted, the ACCC is yet to approve an access arrangement for the MSP. As such, current MSP terms and conditions (including tariffs) are not subject to the National Gas Code. The Council therefore considers that current published MSP tariffs are a guide to MSP prices absent coverage.

7.82 The Council observes that there is scope for "without coverage" pricing outcomes to deviate from published tariffs, due to commercial negotiation. However, EAPL's market behaviour suggests that its published tariffs are the actual rates paid by all customers. For example, in a letter to shippers in July 2000, EAPL notified a price reduction on the MSP and stated that:

> *The amended published tariff will apply retrospectively to all classes of service and to existing and new contracts with all customers from 1 July 2000 (EAPL 2000b).*

7.83 While current MSP tariffs are a guide to MSP prices absent coverage, those tariffs may nonetheless be affected by the regulatory environment. In particular, current tariffs may contemplate coverage and the regulatory processes that arise from coverage. This could result in tariffs being either higher or lower than they would be in an unregulated environment.[79]

7.84 The Council notes that the EGP Longford to Sydney tariff rose by about 6% on 1 January 2002. As this is likely to have raised the price of delivered Gippsland Basin gas relative to delivered Cooper Basin gas in Sydney, there may be scope for the MSP to increase tariffs by an equivalent margin without risking a loss of sales. This would suggest that current MSP tariffs may be lower than MSP prices absent coverage.

[79] For example, it is plausible that the MSP tariff reduction in 2000 (paragraph 4.126) may have been timed to coincide with the ACCC regulatory process, rather than being a true reflection of prices in an unregulated environment. It is therefore possible that MSP tariffs without coverage may be higher than current tariffs.

7.85 The Council further notes that EGP tariffs will escalate once again on 1 January 2003, with ongoing annual escalations, in accordance with a formula based on movements in the Consumer Price Index (Duke 2001b, p.5). The Council considers that, absent coverage, the annual escalation in EGP tariffs may provide ongoing scope for the MSP to further increase tariffs without risking a loss of sales.[80]

Comparing the "with" and "without" scenarios

7.86 For criterion (a), the Council must consider whether the removal of coverage would alter the market conditions that apply "with coverage."

7.87 In comparing these scenarios, the Council must assess whether coverage would constrain the MSP's ability to exercise significant market power in upstream or downstream gas sales markets, as compared with conditions without coverage.

7.88 According to Ordover and Lehr:

> *... since the pipeline "connects" two separate markets – the upstream production market and the downstream retail market – it is necessary to evaluate the ability of the incumbent pipeline to exercise significant market power at least in these two distinct markets. For example, it is conceivable that the incumbent may not be able to exercise market power in one of the markets but be able to exercise market power in the second of the two markets...* (Ordover & Lehr 2001, pp. 10-11).

Duke EGP decision

7.89 In the *Duke EGP decision*, the Tribunal assessed the EGP's ability to exercise market power in dependent markets by considering aspects of industry and market structure, and by making judgements on the

[80] The Council notes the possibility that the EGP could raise its tariffs without increasing the price of delivered Gippsland Basin gas in Sydney, if Gippsland Basin well-head gas prices were falling. However, there is no evidence that EGP tariffs are rising for this reason. Annual price rises for EGP services are predetermined in the EGP's firm forward haulage service contract terms sheet (Duke Energy 2001b).

It is likely, therefore, that annual escalations in EGP tariffs are weakening whatever discipline the EGP may previously have applied to MSP tariffs. Absent coverage, this may allow scope for the MSP to increase tariffs by an equivalent margin to the EGP without risking a loss of sales. This would widen the gap between MSP tariffs absent coverage and the regulated tariffs that would apply if the MSP was covered.

implications of these structural features for the promotion of competition (*Duke EGP decision 2001,* paragraph 116).

7.90 The Tribunal identified the following as relevant factors in determining whether the EGP could exercise market power in a dependent market:

(a) the demand for gas and consequently, gas transportation into Sydney;

(b) available pipeline capacity to supply that demand;

(c) likely spare capacity;

(d) the commercial imperatives facing Duke Energy;

(e) the countervailing power of other market participants in dependent markets; and

(f) competition from other pipelines (the MSP and Interconnect).

7.91 The Tribunal found that coverage of the EGP would not promote competition in upstream or downstream markets because the pipeline lacks sufficient market power to impede competition.

7.92 A number of stakeholders argue that if the EGP lacks market power, it follows that an equivalent finding would apply to the MSP (APIA, the Australian Gas Association, Duke Energy, EAPL/NECG; subs 3,6,8,9,11). According to APIA:

> *…proper assessment of the factors that led the Tribunal to conclude that the EGP should not be covered will also lead to the conclusion that there is no basis for being satisfied that coverage of the MSP will promote competition in the markets under consideration. APIA submits that the Council should therefore recommend revocation of coverage of the relevant pipeline and in doing so allow the best, rather than second-best, outcome to prevail.* (APIA 2001, sub. 11, p.4)

7.93 According to Duke Energy:

> *On the basis of the Tribunal findings concerning the transmission market and the emerging competition in the Eastern States Gas Sales Market… the MSP will not have sufficient market power to 'hinder competition' and, in consequence, continuation of Coverage cannot promote*

> *competition in either the upstream or downstream market.* (Duke Energy 2001, sub. 3, p.17)

7.94 Similarly, EAPL argued that:

> *…the Council must conclude, as the Tribunal did in relation to the EGP, that the MSP does not have sufficient market power to hinder competition in upstream or downstream markets. As the Tribunal found in the case of the EGP, this is based on the strong commercial imperatives EAPL faces, the countervailing power of other market participants, the existence of spare pipeline capacity and the competition it faces from the EGP. Accordingly, the Council cannot be satisfied that coverage will promote competition in either the upstream or downstream markets* (EAPL 2001, sub. 6, p.3).

7.95 The Council agrees that each of the factors raised by EAPL are relevant to whether a pipeline can exert substantial market power in relation to a dependent market. But the significance of each factor needs to be assessed in relation to the circumstances of a particular pipeline. An assessment of each factor in relation to the EGP cannot be simply transferred to the MSP to rebut a proposition that the MSP has substantial market power. Each factor needs to be considered in relation to the characteristics of demand for MSP services, and demand and supply conditions in relevant upstream and downstream gas sales markets.

7.96 The view that the Tribunal's finding on market power with respect to the EGP should apply equivalently to the MSP appears to derive from the fact that:

(a) both the MSP and the EGP deliver gas into the downstream gas sales market in Sydney, providing at least the potential for a gas supply alternative to customers; and

(b) the Tribunal cited competition between pipelines as a factor constraining the EGP's market power.

7.97 The Council notes that there are a number of differences between the Tribunal's findings on the EGP and the circumstances of the MSP. The Council analyses these differences at Attachment 4, and draws on a number of relevant points throughout the body of this report. In summary, the principal differences are:

(a) The EGP is or may be constrained by competition in the Gippsland Basin upstream market, as the Gippsland Basin producers have viable alternatives to the EGP for shipping their gas. The Tribunal noted the following alternatives: gas sales to Sydney via the Interconnect; and gas sales to Victoria (*Duke EGP decision 2001, paragraphs 117-118*). The Council notes that the opening of the Tasmanian Gas Pipeline in 2002 (paragraph 4.71) provides a third potential sales alternative for the Gippsland Basin producers. However, the Council considers that the Cooper Basin producers do not have viable alternatives to the MSP for shipping their gas (paragraphs 7.133 to 7.185). This is likely to confer market power on the MSP in relation to the Cooper Basin upstream gas sales market.

(b) Both the Interconnect and EGP provide a service between Longford and Sydney (and between various locations along their respective routes).[81] The Tribunal's finding that there is low-cost developable capacity on the Interconnect means that there is some direct competition in pipeline services between the Interconnect and the EGP. This was a major factor in the Tribunal's finding that the EGP lacks market power. In contrast, the MSP has a monopoly in the provision of transportation services between Moomba and Sydney.

These differences also mean that estimates relied on by the Tribunal on the cross-price elasticity of demand between the EGP and the Interconnect (*Duke EGP decision 2001*, paragraphs 106-108), have no relevance to the MSP. Given that the MSP provides a different service to the other pipelines, the cross-price elasticities are likely to be considerably lower.

(c) While there was no evidence of monopoly pricing in the case of the EGP, the Council considers that there is substantial evidence of monopoly pricing on the MSP (paragraphs 7.315 to 7.405).

(d) The EGP faces commercial incentives to develop new regional markets through competitive pricing (*Duke EGP decision 2001*, paragraphs 125-133). Similar incentives are

81 When the Council refers to the Interconnect as providing a service between Longford and Sydney, it is using shorthand to describe a service provided by a combination of pipelines between Longford and Sydney, incorporating: the Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline.

less apparent in regional markets served by the MSP, as those markets are well-established (paragraphs 7.293 to 7.301).

(e) The Tribunal did not view vertical linkages between Duke Energy, Duke Energy Australia Trading and Marketing Limited (DEATM) and the EGP as a barrier to competition, because DEATM's commercial strategy was to develop a diversified portfolio using gas from multiple sources and shipped via multiple pipelines (*Duke EGP decision 2001*, paragraphs 27-37). However, relationships between AGL, AGLWG and the MSP have traditionally been more exclusive. AGLWG appears to have dealt exclusively with the Cooper Basin producers and EAPL/MSP. In addition, the Council notes that while a significant proportion of MSP capacity is contracted to AGLWG, especially until 2006, the EGP does not have contractual arrangements of this magnitude with DEATM (paragraphs 7.581 to 7.582).

7.98 In addition, the Council notes that the Tribunal reached its finding that the EGP lacks substantial market power against an environment in which the MSP and Interconnect were covered pipelines, making them subject to regulated access, including a price derived from efficient costs. It was against this background, therefore, that the Tribunal found that competition from other pipelines was a factor constraining the EGP's market power.

7.99 The Council concludes that notwithstanding that the EGP lacks market power, it cannot be assumed that this finding would extend to the MSP. The application needs to be considered in the context of the specific circumstances of the MSP.

The Ordover and Lehr framework

7.100 The Tribunal's *Duke EGP decision* focussed on pertinent aspects of industry and market structure of specific relevance to the EGP. The Tribunal did not indicate that the list of factors upon which it based its decision was necessarily an exhaustive one for assessing competitive conditions in dependent markets in all instances.

7.101 Ordover and Lehr propose a generic model for analysing criterion (a), focussing on the ability and incentives open to a pipeline owner to exploit market power in relation to a dependent market. There are two plausible reasons why a pipeline with monopoly power over transport might use this to impact on competition in upstream or downstream markets. First, it may seek to do this to exploit its monopoly position in the market for pipeline services. Second, insofar as the pipeline has vertical interests, it may seek to extend, protect, or exploit whatever market power it may have in either upstream or downstream markets (Ordover and Lehr 2001, p.10).

7.102 This behaviour can inhibit competition in dependent markets in a number of ways. For example:

(a) monopoly pricing of gas transportation is likely to result in higher delivered gas prices (which would weaken demand for gas) and/or lower returns in gas production and/or gas sales. These conditions are likely to reduce gas production and distort entry incentives in upstream and downstream markets, weakening the competitive environment in those markets.

(b) using the terms and conditions of pipeline access to disadvantage some firms and advantage others may distort entry incentives in dependent markets (Ordover and Lehr 2001, p.11).

7.103 Ordover and Lehr draw on this framework to develop the Tribunal's approach in the *Duke EGP decision* into a model for assessing competitive conditions in dependent markets. The model provides a broad analytical framework that encompasses each factor identified by the Tribunal, as well as other relevant factors, and may be applied in a wide range of circumstances.

7.104 The Ordover and Lehr model proposes three lines of inquiry for assessing whether a pipeline owner has the incentive and ability to exploit market power (ie, inhibit competition) in upstream and/or downstream markets. The lines of inquiry are:

(a) the ability of the relevant pipeline owner to charge monopoly prices for transport services;

(b) the ability of the relevant pipeline owner to engage in explicit or implicit price collusion; and

(c) other incentives and opportunities for the relevant pipeline owner to distort competition in adjacent markets.

7.105 The model addresses each of the issues identified by the Tribunal in the *Duke EGP decision*. In particular:

(a) the first line of inquiry takes account of the following factors identified by the Tribunal: countervailing market power of other market participants; market behaviour in upstream and downstream markets; competition “between” pipelines; pipeline capacity, gas reserves and demand issues; the role of long-term contracts; evidence on elasticity of demand, including cross-price elasticities;

(b) the second line of inquiry takes account of the following factors identified by the Tribunal: the depth of competition in gas transportation markets, issues of parallel pricing, long-term contracts, price discrimination, information disclosure and the role of spare capacity in constraining market behaviour; and

(c) the third line of inquiry takes account of the following factors identified by the Tribunal: vertical leveraging issues, market behaviour, commercial imperatives facing the pipeline, long-term contracts.

Given that the Ordover and Lehr model considers each factor identified by the Tribunal, and provides a broad analytical framework that may be applied across a range of circumstances, the Council considers it appropriate to adopt this framework in considering whether the MSP Mainline and Canberra Lateral satisfy criterion (a).

7.106 EAPL argues that the Council’s adoption of the Ordover and Lehr model is an inappropriate transition from the Tribunal’s approach:

> *...the Council approaches the issue on the basis of three “key elements” identified by Ordover and Lehr, effectively substituting these elements for the test established by the Tribunal. The Draft Recommendation does not accurately reflect the Tribunal’s findings and approach and therefore fails to properly apply the law and relevant facts* (EAPL 2002, sub.19, p.7).

7.107 The Council reiterates that the Ordover and Lehr framework is wholly consistent with the Tribunal’s approach, but further develops that approach by providing a robust theoretical framework that may be applied to any coverage matter under the Code.

7.108 The Council now turns to each line of inquiry in the Ordover and Lehr model.

Ordover and Lehr (a): Ability and incentive to charge monopoly prices

7.109 Ordover and Lehr's first line of inquiry for gauging the MSP's ability to exert market power in a dependent market focuses on whether the MSP has the ability and incentive to charge monopoly prices (that is to price substantially above long run economic cost). If so, the pipeline can translate its market power in the supply of transport services into dependent markets.

7.110 If the MSP charges monopoly prices, the delivered cost of gas in downstream markets is likely to rise above efficient levels.[82] This would suppress demand for gas, weakening entry incentives in downstream markets and the upstream gas sales market. According to Ordover and Lehr:

> *... (A)bsent coverage or any other form of price regulation, the MSP may be able to set prices for transport services that substantially exceed its forward-looking, long-run economic costs. This would have the effect of increasing the delivered cost of gas in the NSW/ACT markets, which would, in turn suppress demand for upstream production from the Cooper Basin. As we discuss further below, this appears to be the case under the current MSP tariffs (Ordover and Lehr 2001, p.12).*

7.111 Alternatively, monopoly pipeline prices could be partly absorbed through reduced returns in gas production and/or gas sales. This would also weaken entry incentives in dependent markets. Ordover and Lehr conclude that:

> *The combination of lower upstream and downstream margins from above-competitive transport rates, will tend to reduce incentives to invest in both upstream and downstream markets and therefore could have an adverse effect on competition in both of these markets (Ordover and Lehr 2001, p.13).*

Elasticity of demand

7.112 Whether a pipeline faces incentives to charge monopoly prices depends on demand and supply conditions for the pipeline's services.

7.113 On the demand side, the elasticity of demand for gas (and gas pipeline services) is an important consideration. Elasticity of demand

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82 Delivered gas prices may also be above efficient levels if the gas commodity component is priced at monopoly rates.

refers to the responsiveness of gas demand to price movements. For example, if gas demand is inelastic (not very responsive to price movements), there is greater opportunity and incentive to charge monopoly prices – because monopoly prices would not significantly weaken demand. Relatively inelastic demand for gas is likely to translate into relatively inelastic industry demand for gas pipeline services:

> *If aggregate demand for natural gas at a particular location (say, Sydney) is relatively inelastic at current prices, and because transport costs represent only about 10% of the delivered cost of natural gas, the reduction in demand for pipeline services from a price increase is likely to be small.* (Ordover and Lehr 201, p.12)

7.114 However the firm-specific demand for a particular pipeline's services may be less inelastic if customers have viable alternative gas supplies at a competitive price:

> *The elasticity of demand for a given pipeline's transport services depends not only on the ability of customers to switch to other fuels but, also, on the ability to switch to other suppliers of gas. If the ability of end users to shift demand to other sources of natural gas away from MSP is also small at a "competitive" price, then a price increase above that level would likely be profitable for the MSP. Indeed, as we discuss further below, the ACCC's draft access decision suggests that current rates are substantially above the pertinent economic costs* (Ordover and Lehr 2001, p.12).

7.115 The most recent Australian study available, covering 1973-74 to 1993-94 data, suggests that demand for gas is relatively inelastic, especially among commercial and industrial gas users (paragraphs 4.145 to 4.151). The Council elsewhere notes that it may be misleading to extrapolate from this historical data to current market conditions (paragraphs 7.419 to 7.430). However, on the limited evidence available, there are grounds for assuming that demand for gas is likely to be relatively inelastic. Since pipeline services make up only a portion of the overall delivered cost of gas, it is likely that the overall demand for pipeline services will be even more inelastic (Ordover and Lehr 2001, p.22).

7.116 An indicator of the demand sensitivity of a particular pipeline to price changes is the cross-price elasticity of demand between pipelines or (more accurately) between alternative sources of delivered gas to NSW/ACT markets.[83] Cross-price elasticity of demand measures how a price change for one product affects the demand for another product. For example, a low cross-price elasticity of demand would indicate that customers would not respond to monopoly pricing on one pipeline by switching to another. Ordover and Lehr state that while it is plausible that the cross-price elasticity of demand between sources of delivered gas may be high, there is no empirical evidence on the size of the relevant cross-price elasticities (Ordover and Lehr 2001, p.20). The Council considers that it is therefore difficult to draw conclusions about the MSP's market power from a consideration of the cross-price elasticity of demand between pipelines or (more accurately) delivered gas products.[84]

7.117 Incentives for monopoly pricing of pipeline services are especially potent if there are opportunities to expropriate some of the rents associated with sunk investments in the upstream production market. The Council notes that such opportunities are plausible, given that Cooper Basin gas production is controlled at present by a single joint venture entity (paragraph 4.14).[85] Ordover and Lehr argue that the mere threat of opportunistic behaviour by the pipeline owner could distort entry incentives and competition in upstream markets (Ordover and Lehr 2001, p.21).

7.118 Ordover and Lehr conclude their analysis of the risk of the MSP expropriating upstream rents by stating that:

> *Coverage may reduce the risk of anticompetitive behaviour associated with the threat to expropriation of sunk costs by constraining prices and the scope of feasible contracts for transport* (Ordover and Lehr 2001, p.21).

83 The Council explains at paragraph 7.199 that to the extent that downstream competition exists in Sydney and Canberra gas sales markets, it is between different sources of delivered gas (that is, gas bundled with pipeline services).

84 The Council further considers evidence on the relevant cross-price elasticities at paragraphs 7.245 to 7.257 and paragraphs 7.543 to 7.549. In those sections, the Council explains its view that the relevant cross-price elasticities are likely to be high at current price levels. However, cross-price elasticity estimates at current prices are misleading in the presence of monopoly pricing. The Council concludes, from the evidence, that cross-price elasticities of demand between the MSP and other pipelines are not likely to be substantially above 1.0 at competitive price levels.

85 The feasibility of this behaviour also depends on countervailing market power of the Cooper Basin producers: see paragraphs 7.132 to 7.196.

7.119 The Council considers that demand for gas pipeline services is likely to be relatively inelastic, and that this creates incentives for monopoly pricing on the MSP. These incentives are likely to be more potent given the potential for the MSP to expropriate a share of upstream rents from the Cooper Basin producers. The extent of these incentives would be clarified by data on the cross-price elasticity of demand between the MSP and other pipelines, or between alternative sources of delivered gas to NSW/ACT markets. Reliable empirical evidence on this matter is not available.

Capacity and cost considerations

7.120 EAPL argues that spare capacity on the MSP, combined with the cost characteristics of gas pipelines, result in commercial incentives for EAPL to maximise MSP throughput. This strategy would be consistent with efficient pipeline tariffs. According to EAPL:

> *... because neither EAPL nor APT, its parent company, have any upstream or downstream interests, if they do not sell access they do not have a business. Nothing would be gained, and business opportunities would be potentially lost, through any attempt to restrict output or failure to maximise transportation volumes* (EAPL 2001, sub.6, p.6).

7.121 The issue of vertical interests is addressed from paragraph 7.512 of this report. Below, the Council considers the implications of excess capacity and the cost characteristics of gas pipelines.

Excess capacity

7.122 The Council notes the Tribunal's finding in the *Duke EGP decision* that pipeline capacity constraints will not impede competition in south-east Australian gas markets over the next 10-15 years (*Duke EGP decision 2001*, paragraphs 22, 95, 97).

7.123 The Council accepts that excess pipeline capacity makes competition in downstream gas sales markets more feasible than if the MSP was capacity constrained. However, competition must be examined both in upstream and downstream markets. As Ordover and Lehr note, capacity constraints may attenuate competition in the upstream market, at least in the short to medium term. Although Cooper Basin gas is being sold into retail market outside NSW/ACT, capacity on the most important alternative route to the MSP, the Moomba-

Adelaide pipeline, is constrained in at least the short to medium term.[86] This means that the MSP may have monopsony power (buyer market power) with respect to production from the Cooper Basin field. The Council considers this matter in paragraphs 7.132 to 7.185 and 7.196) of this report.

Cost characteristics of gas pipelines

7.124 The cost characteristics of gas pipelines (high fixed costs, low incremental costs) is another factor which, in itself, creates incentives for high rates of pipeline throughput:

> *Pipeline services are characterised by high fixed costs (associated with the pipeline itself) and rather low marginal (or incremental) cost of transport (at least as long as there is available capacity). This means that, up to capacity, the pipeline would find it incrementally profitable to transport additional gas even at a price that may be below long run average costs. It also means that price competition between the MSP and EGP could be quite aggressive, especially in the short-term. This is because the pipelines will ignore their sunk and fixed costs when setting prices. As a result, prices may fall below the level needed to sustain long-term viability* (Ordover and Lehr 2001, p.23).

7.125 While the characteristics of gas pipelines *may* create incentives for high rates of throughput, there is still a risk of monopoly pricing and associated restrictions in output. According to Ordover and Lehr:

> *Opponents of coverage of the MSP have argued that this cost structure ... reduces the risk that the MSP might abuse any monopsony power it may have to limit access to the pipeline since its profits are likely to be maximised if it maximises throughput. If the MSP has monopsony power in the upstream market but faces effective competition in the downstream market (*i.e., *the MSP takes prices as given in the downstream market), then its incentive to exercise monopsony power (by lowering the effective price it pays upstream producers) is reduced relative to the scenario where it also has downstream market power. However, this does not mean that such incentive is non-existent. And neither does it mean that low decremental costs (i.e., costs that MSP would avoid if it were to cut back on throughput) per force render the exercise of monopsony power unprofitable* (Ordover and Lehr 2001, p.23).

86 See ACCC 2001a, pp 48, 129, 171, 174, 186 and 188.

7.126 Similar reasoning applies to downstream markets. The MSP's low marginal costs and high fixed costs do, in themselves, create incentives for high levels of throughput in the absence of substantial market power. But these characteristics do not remove the risk of monopoly pricing:

> *Just because marginal costs are low, does not mean that the optimal pricing strategy is to fill the pipe to capacity* (Ordover and Lehr 2001, p.23).

7.127 The critical determinant of whether monopoly pricing will be profitable to the MSP is whether there is effective competition in dependent markets.

Competition in dependent markets

7.128 The competitive environment in dependent markets affects the MSP's incentives for monopoly pricing as well as its ability to implement such a pricing strategy. In this sense, effective competition in dependent markets would constrain the MSP's ability to exercise market power in those markets. According to Ordover and Lehr:

> *The existence of effective competition precludes the ability profitably to exercise monopoly power, and therefore, a finding that effective competition exists in a market is usually taken to be equivalent to a finding that no firm in that market possesses substantial market power. In the presence of effective competition, prices are driven towards economic costs and resources are allocated efficiently* (Ordover and Lehr 2001, p.7).

7.129 This would suggest that the MSP's ability to engage in monopoly behaviour is effectively constrained if:

(a) downstream parties are able to shift their demand to alternative sources of natural gas (via pipelines other than the MSP) at a competitive price; and

(b) producers in the upstream market can sell their gas to alternative destinations (via pipelines other than the MSP) at comparable rates of return.

7.130 If upstream and downstream markets are effectively competitive, the case for coverage lapses. According to Ordover and Lehr:

> *Ultimately, if the MSP faces effective competition in both the upstream (*i.e., *Cooper Basin producers can sell their gas to other*

> *retail markets not served by the MSP) and the downstream market (*i.e., *there are substitute sources of gas supply to the NSW/ACT retail markets that do not depend on the MSP), then the MSP will not be able to effectively exploit its presumed monopoly power in the provision of pipeline services between Cooper Basin and NSW/ACT. If this is the case, then coverage which would limit the potential for the MSP to abuse its notional market power would not improve conditions for competition in the upstream or downstream markets* (Ordover and Lehr 2001, p.19).

7.131 In the following sections, the Council considers whether there is effective competition in upstream and downstream markets to constrain monopoly pricing on the MSP.

Upstream competition

7.132 If the MSP has monopsony power in the upstream market for Cooper Basin gas[87], it may be able to dictate transportation tariffs to upstream producers. But the MSP's market power may be constrained if:

(a) upstream producers can market their gas to a range of destinations at equivalent prices to those earned on marginal sales to NSW/ACT markets; or

(b) if the producers themselves have countervailing market power.

Alternate outlets for the sale of Cooper Basin gas

7.133 The ability of the MSP to charge monopoly tariffs would be constrained if gas producers can sell their gas to markets other than markets in NSW/ACT currently served by the MSP. If viable options exist, upstream producers will only sell gas to NSW/ACT markets via the MSP if they can earn a similar return on the marginal unit of gas shipped to NSW/ACT as they earn on shipments to other regions. The MSP would then be unable to lower the price it pays to upstream producers, or equivalently, charge monopoly prices to producers for transporting their gas to downstream markets.

87 The dimensions of the upstream market are noted in paragraph 7.19 of this report.

7.134 The effectiveness of this constraint depends on a number of factors, including demand conditions in downstream markets, and available capacity on the alternative pipelines:

> *The strength of this competition depends on the available capacity on alternative pipelines as well as the retail prices of gas in the destination markets of these pipelines. If the aggregate capacity of these pipelines is small relative to total output of the gas field, the concern that transport to NSW/ACT may be overpriced is not necessarily obviated. For example, the dominant pipeline may "allow" its smaller rivals to bid for all the output that they can profitably take and then charge a supracompetitive rate for transporting the remaining share of gas output* (Ordover and Lehr 2001, p.17).

7.135 EAPL/NECG argue that the Cooper Basin producers have a range of options for selling gas, which enable them to defeat monopoly pricing on the MSP. The options proposed by EAPL/NECG include diverting gas sales into:

(a) South Australian markets (via the Moomba to Adelaide pipeline); or

(b) Queensland markets (via the Ballera to Moomba pipeline).[88]

(a) Moomba to Adelaide pipeline

7.136 EAPL/NECG argue that one option open to the Cooper Basin producers is to divert gas sales from NSW/ACT markets to South Australia via the Moomba to Adelaide Pipeline System (**MAPS**), a covered pipeline under the National Gas Code.

7.137 In its draft recommendation, the Council expressed doubt as to the viability of this option, given that the MAPS is currently operating at full capacity. In particular, the Council referred to information from the ACCC that the MAPS is fully contracted until the end of 2005. The ACCC noted in its September 2001 determination on the MAPS that:

88 NECG also propose that the Cooper Basin producers could defeat monopoly pricing on the MSP by reducing production at Moomba – that is, leave gas in the ground until market conditions improve. In later discussions with the Council, NECG expressed reservations about the viability of this scenario. For this reason, the Council does not further explore the scenario.

> *... the current access dispute under the SA Natural Gas Pipelines Access Act 1995 indicates that there is insufficient capacity on the MAPS to meet current requirements. Moreover, it is apparent that demand for capacity on the MAPS from 2006 is in excess of total capacity. This is the case, even with the expiration of the existing haulage agreements that account for the vast majority of current throughput on the MAPS* (ACCC 2001a, p.48).

7.138 Epic Energy, owner of the MAPS, has confirmed to the Council that the pipeline is operating at its current capacity. As set out in the access arrangement for the MAPS and the ACCC's final decision and further final approval for the pipeline's access arrangement, the maximum potential capacity of the MAPS is in the order of 418 TJ/day. However, the maximum capacity that can be booked on the MAPS for a firm service is 348 TJ/day (defined in the access arrangement as the system primary capacity of the pipeline).

7.139 The existing system primary capacity of the pipeline (ie 348 TJ/day) is currently fully contracted up until the end of 2005. As a result, there is no scope for utilisation of any existing capacity (up until the maximum potential capacity of 418 TJ/day) on the pipeline until the end of 2005.[89]

7.140 Notwithstanding the above there is scope to substantially increase capacity on the pipeline for firm services through compression and progressive looping. Epic estimates that fully looping the pipeline, combined with upgraded compression would substantially increase the pipeline's current capacity.

7.141 Once the pipeline is fully looped, there would then be scope to progressively "triplicate" the pipeline. The economics of this exercise are not substantially different from looping the original pipeline.

7.142 While there are no significant technical constraints to expanding the pipeline's capacity for firm services, the principal issue would be to determine who pays for an expansion, and under what terms and conditions. The Council considers that this may be determined through commercial negotiation, or failing this, under the arbitration provisions of the National Gas Code.

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89 The reference service specified in the access arrangement is a firm service known as the FT Service. The FT Service is a firm service that can only be interrupted in the case of a force majeure event. The total allowable revenue for the MAPS approved by the ACCC is derived on the basis that only FT Services will be utilised on the pipeline and therefore only the system primary capacity will be able to be utilised.

7.143 The Council considers that the possibility of capacity expansions on the MAPS is a relevant consideration in gauging MSP's market power, but observes from the facts provided by Epic Energy that such an expansion would take time as well as the resolution of a number of commercial issues.

7.144 The possibility of new pipeline development is another relevant consideration. EAPL has pointed out that capacity constraints on the MAPS would be eased by the proposed SEA Gas pipeline between Victoria's Otway Basin and Adelaide (paragraph 4.68). The proposed pipeline would connect an additional source of supply with Adelaide gas sales markets and "complete the loop" of transmission pipelines in south-eastern Australia.

7.145 The Council understands from discussions with the Department of Primary Industries and Resources (South Australia) that there is a high probability of the SEA Gas Pipeline being completed by 2004, and that it could attract significant loads from the MAPS, given that major contracts for the MAPS are due to expire between 2003-2006.

7.146 The Council understands that the SEA Gas Pipeline would have an initial capacity of 60-70 PJ/a, with a maximum expandable capacity of 125 PJ/a. If the pipeline is built, total spare capacity on pipelines serving South Australia is likely to be substantial.

7.147 The Council considers that short term and longer term horizons are relevant in considering the possible effects of speculative events on markets.[90] As a general rule, the relevance of a future event to the promotion of competition test should reflect the probability of the event occurring.

7.148 From the above analysis, the Council concludes that redirecting NSW/ACT gas sales into South Australian markets via the MAPS is not viable in the short term as capacity on the pipeline is fully contracted. In the longer term, this capacity constraint could be overcome if commercial impediments to expanding the MAPS are resolved; and/or if pipeline interconnection between South Australia and Victoria frees up capacity on the MAPS.

7.149 The Council notes, however, that resolution of capacity issues would not, in itself, be a sufficient condition to make the South Australian option an effective constraint on the MSP – even in the long term.

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90 For a discussion of this issue, refer to paragraphs 7.50 - 7.57 of this report.

The viability of this option would depend on whether South Australia's demand for gas can grow rapidly enough to absorb the necessary diversions of gas sales from NSW/ACT at prices at least equivalent to marginal returns in those markets. The Council considers this matter in paragraphs 7.174 to 7.185.

(b) Ballera to Moomba pipeline

7.150 According to NECG, the Cooper Basin producers and the South-West Queensland producers in the Eromanga Basin are "in effect a single commercial entity." (NECG 2002, sub. 19, App. G, p.9). The two basins are connected by the Ballera (Queensland) to Moomba (South Australia) raw gas pipeline (see paragraph 4.65).

7.151 NECG argues that these arrangements give the Cooper Basin producers another alternative for diverting sales from NSW/ACT markets to defeat monopoly pricing on the MSP: the producers could divert sales into Queensland markets via the Ballera to Moomba pipeline.

7.152 According to EAPL:

> *... the Cooper Basin producers own a pipeline running from Moomba to Ballera in South East Queensland. That pipeline is currently used for transportation of natural gas from Ballera to Moomba; there is potential for it to be used to transport gas from Moomba if the producers choose to do so* (EAPL 2002, sub.19, p.13).

7.153 The Ballera to Moomba Pipeline conveys semi-processed ("raw") gas from the SWQ Production facility at Ballera (Queensland) to the SACBUP production facilities at Moomba (in South Australia). Santos owns a 60% share in the pipeline, which is not a covered pipeline under the National Gas Code.

7.154 The pipeline serves a dual purpose. First, it provides a means to dispose of liquid by-products from gas production at Ballera. The gas liquids (condensate and liquid petroleum gases) are shipped by pipeline to Port Bonython (South Australia) for processing and sale.

7.155 Second, raw gas shipped along the pipeline is processed into sales gas at the Moomba plant, and sold into South Australian and NSW/ACT markets. The Council understands from discussions with Primary Industries and Resources SA that a significant proportion of

South Australia's gas demand is currently sourced from Queensland via the Ballera to Moomba pipeline.

7.156 Diverting gas sales from NSW/ACT to Queensland via the Ballera to Moomba pipeline would require the following modifications to the current configuration of the pipeline:

(a) the pipeline would need to be converted from a raw gas pipeline into a sales gas pipeline; and

(b) the flow of the pipeline would need to be reversed to allow gas to be shipped from Moomba to Ballera.

7.157 Technical configuration of the Ballera to Moomba pipeline does not allow it to carry fully processed gas. The Council understands that there would be no significant technical constraints to reconfiguring the pipeline to address this issue. Indeed, the pipeline had been envisaged as being essential in an emergency response if Moomba was disabled.

7.158 The principal constraint to converting to a sales gas pipeline relates to the processing facility at Ballera. The Council understands from Queensland officials that, due to capacity constraints at the Ballera facility, it may not be possible to convert current loads on the pipeline into fully processed sales gas. In addition, the Ballera facility would require an alternative means of disposing of liquid by-products. There is currently no means to dispose of these by-products in Queensland, and an alternative would have to be developed if the Ballera to Moomba pipeline was reconfigured as a sales gas pipeline.

7.159 Reversing the flow of the pipeline is technically feasible. However, this would require resolution of the issue of liquids disposal at Ballera. There would also be ramifications for gas supply contracts to South Australia, including deliveries of liquid by-products to the Santos plant at Port Bonython (South Australia). Given that a substantial proportion of South Australian gas deliveries is currently sourced from Queensland via the Ballera to Moomba pipeline, reversing the flow of the pipeline would leave a shortfall in capacity to meet those deliveries. One theoretical option would be to increase production in the Cooper Basin to meet the shortfall. But according to information from Primary Industries and Resources SA (PIRSA), trading off increased production in the Cooper Basin against Eromanga Basin gas may not be a commercial proposition.[91]

7.160 An alternative possible means of pursuing gas sales from the Cooper Basin to Queensland is through swap arrangements. This would require increased production of sales gas at Ballera, and higher rates of gas sales into Queensland markets. This scenario, once again, is likely to be impractical due to capacity constraints at Ballera. The scenario also assumes that the Cooper Basin producers (SACBUP) and Eromanga Basin producers (SWQ producers) operate as a single entity. At the very least, the scenario is likely to require the resolution of contractual and legal issues. It also makes a number of assumptions about the flexibility of production schedules in both the Cooper and Eromanga Basins.

7.161 Another scenario might involve the construction of a sales gas pipeline from Moomba to Ballera (with northbound gas flow) to provide a means of diverting gas sales to Queensland. The Council is aware that Epic Energy was granted a Preliminary License by the South Australian Government in September 2002 to conduct survey activities with a possible view to constructing a pipeline between Ballera and Moomba. No official information is available on the proposed direction of gas flows. Nor is the Council in a position to assess the likelihood of the pipeline being constructed. In the circumstances, the Council is unable to assess any implications for the prospects of diverting gas flows from NSW/ACT to Queensland.

7.162 Apart from the technical, commercial and capacity issues outlined above, there are additional capacity issues that would need to be addressed to allow Cooper Basin gas sales to be diverted into major Queensland markets. A significant issue is that the Roma to Brisbane gas pipeline (part of the network connecting Ballera with south-east Queensland markets) is capacity constrained, and has been fully contracted for many years.

7.163 Nor would resolution of all technical, commercial and capacity issues be sufficient to make the Queensland option an effective constraint on MSP pricing. The viability of the Queensland scenario would

91 At the margin, Queensland gas (Eromanga Basin) can be produced at lower cost than South Australian (Cooper Basin) gas – because the South Australian fields are characterised by lower pressure due to field depletion. In addition, raising production in South Australia is likely to require drilling more wells than would be required by an equivalent production increase in Queensland.

require that Queensland gas demand grow rapidly enough to absorb the necessary diversions of gas sales from NSW/ACT at prices that provide similar marginal returns to those markets. It would also require that any growth in demand be satisfied from gas produced (or swapped) by the Cooper Basin producers, rather than from other sources.

7.164 The Council concludes that the Queensland scenario is highly speculative. In the short term, the scenario appears to be infeasible due to capacity constraints at Ballera and on the Roma to Brisbane pipeline, and due to other technical and commercial issues. While delivery of Cooper Basin gas into Queensland markets cannot be discounted as a possibility in the longer term, the Council has seen no evidence to suggest that the constraints outlined above will be resolved in the foreseeable future.

Critical loss analysis

7.165 In paragraphs 7.133 to 7.164, the Council considered claims that the Cooper Basin producers have gas sales options in Queensland and South Australia that constrain monopoly pricing on the MSP. NECG conducted critical loss analysis to estimate the quantum of gas sales that would need to be diverted into Queensland and South Australian gas sales markets to constrain monopoly pricing on the MSP (NECG 2002 sub.19, App.G, pp.10-13).

7.166 The analysis assumes that sales can be readily diverted into South Australian and Queensland markets via the MAPS and Ballera to Moomba pipeline respectively. The analysis is designed to show that even a small price increase on the MSP could result in a significant loss of volume that would be unprofitable to the pipeline's owners. This reflects the truism that the MSP has very high fixed costs relative to variable costs (as is typical of gas pipelines). Thus, any loss of sales would be closely reflected in a loss of profit.

7.167 The NECG critical loss analysis considered the level of gas sales the Cooper Basin producers would need to divert to other destinations in the event of MSP tariffs rising by:

(a) 5%; and

(b) 10%.

7.168 NECG estimated that the Cooper Basin producers would need to divert only 5.7PJ to other markets to make a 5% price rise unprofitable to the MSP. A 10% tariff increase on the MSP would require a 10.8 PJ diversion.

7.169 From this analysis, NECG concludes that the Cooper Basin producers have significant countervailing market power when dealing with the MSP.

7.170 The Council makes the following observations. First, the NECG analysis considers the level of sales diversions that would be needed to defeat an MSP price rise of 5% and 10%. The Council provides evidence elsewhere in this report that the MSP may be pricing about 30% above efficient costs (see paragraphs 7.315 to 7.405). Clearly, the level of sales diversions needed to defeat this degree of overpricing would be greater than the diversions needed to defeat overpricing by 5% or 10%.

7.171 Second, critical loss analysis does not prove that substitution *will* occur, but merely shows the extent of substitution that would deter a price rise. In practice, a range of factors may limit scope for substitution. For example, the Council has noted the capacity constraints on the MAPS (in the short to medium term, at least) and the complex array of technical and commercial issues that would need to be addressed for the Cooper Basin producers to divert gas sales into Queensland markets. The Council has also noted that the feasibility of substitution depends on whether gas demand in South Australia and Queensland is strong enough to absorb the required diversions of gas sales from NSW/ACT markets to constrain monopoly pricing on the MSP.

7.172 The Council has found that there is no scope to ship Cooper Basin gas to Queensland at present, and that there is no evidence to suggest that this will change in the foreseeable future (paragraphs 7.150 to 7.164). The Council has also found that while the Moomba to Adelaide Pipeline currently lacks the capacity to increase gas sales from the Cooper Basin to Adelaide, capacity may become available if the SEA Gas Pipeline is completed by around 2004 (paragraphs 7.136 to 7.149).

7.173 Hence, while there is no foreseeable prospect for the Queensland scenario to become feasible, there is a reasonable probability that the South Australian scenario may be technically feasible in the long run. The Council therefore focuses its assessment of NECG's critical loss analysis on the South Australian scenario, given the probability that physical capacity may exist in the longer term to implement this scenario.

South Australian demand for gas

7.174 Demand for gas in South Australia is closely tied to demand for electricity and infrastructure investment in electricity generation. The Council understands from discussions with Primary Industries and Resources SA that South Australia's gas sales market has become increasingly volatile since energy deregulation, making demand difficult to forecast. A number of proposed infrastructure projects, if completed, would significantly impact on demand. These projects include the South Australian Magnesium Project (SAMAG), various mineral sands projects, and further expansion of the WMC Olympic dam facility. Electricity Supply Industry Planning Council forecasts, published in June 2002, indicate that the State's total demand for gas will grow, on average, by 2.5% to 4.5% per year over the period 2001-02 to 2011-12.[92] Both the high and low range forecasts take account of a proposed expansion of the Pelican Point electricity generation facility (2004-2005), and stage 1 of an expansion of the ATCO gas-fired power station at Osbrone (2003-2004). The higher (4.5%) rate is an optimistic forecast, factoring in such projects as SAMAG and an additional expansion of the WMC Olympic dam facility (ESIPC pp.37-38).

7.175 The Council notes that these forecasts are consistent with other studies. An ABARE study, published in August 2002, projected that gas demand in South Australia would rise by about 2.9% per year over the period to 2019-2020 (Fainstein et. al, 2002, p.29). In addition, National Institute of Economic and Industry Research forecasts on South Australian gas demand, cited by NECG, project that gas consumption in South Australia will rise on average by 2.5% annually to 2014-15 (NECG 2002, sub.19, App.G, footnote 21).

7.176 NECG's critical loss analysis suggests that the Cooper Basin producers would need to divert 5.7PJ to other markets to defeat a 5% price rise on the MSP. The Council observes that South Australia's demand for gas in 1999-2000 was about 87 PJ (AGA 2001, p.61). A diversion of 5.7PJ is therefore equivalent to about 6.6% of current gas sales to South Australia. This would suggest that South Australian gas demand would need to rise by about 6.6% to absorb the necessary diversion of gas sales from the Cooper Basin to constrain MSP pricing. Given that this significantly exceeds the

92 Average annual growth rates over the period 2001-02 to 2011-12. Derived from ESIPC 2002, p.37-38 Tables 6C and 6D.

optimistic ESIPC scenario for annual growth in South Australian gas demand, it is not clear how the Cooper Basin producers could generate the required sales to constrain the MSP in any given year.

7.177 If MSP tariffs rise by 10%, the South Australian scenario becomes an even less plausible constraint. NECG's critical loss analysis suggests that to defeat a 10% price rise on the MSP, the Cooper Basin producers would need to divert 10.8 PJ to other markets. This is equivalent to about 12.4% of current gas sales to South Australia. Thus, South Australian gas demand would need to rise by about 12.4% to absorb the necessary diversion of gas sales from the Cooper Basin. This compares with ESIPC's most optimistic forecast of South Australian gas demand of (on average), about 4.5% per year to 2011-12.

7.178 The Council provides evidence elsewhere in this report that the MSP may be pricing about 30% above efficient costs (see paragraphs 7.315 to 7.405). NECG has not provided critical loss estimates for this scenario. The Council notes that the level of sales diversions needed to defeat a 30% price rise would be greater than the diversions needed to defeat overpricing by 5% or 10%.

7.179 The Council reiterates that even if South Australian gas demand grew at the required rate to absorb diversions of gas sales from NSW/ACT, there is currently no spare capacity on the Moomba to Adelaide pipeline to supply downstream markets. While the Victoria to Adelaide pipeline is expected to free up capacity on the Moomba to Adelaide pipeline, the pipeline would also introduce a second source of gas supply to Adelaide. While it may become physically possible for the Cooper Basin producers to satisfy downstream market growth, it is likely that a significant share of that growth would be met by Victorian gas shipped on the new pipeline. According to the Electricity Supply Industry Planning Council:

> *the ... SEA Gas project will have a significant impact upon the fuel supply for power generation in Adelaide. Commencing in early 2004, it is anticipated International Power and Origin Energy will source the majority of their gas fuel requirements from this system. This will initially free up capacity in the MAP, and could lead to a temporary reduction in purchases from the Moomba Gas Fields* (ESIPC 2002, p.41).

7.180 The Council notes that the new pipeline is expected to have ten year foundation contracts to supply Victorian gas to a number of major gas users, including International Power and Origin Energy (ESPIC 2002, p.40). Given the nature of these contracts, foundation customers may be not be open to sourcing gas supply from the Cooper Basin/MAPS.

7.181 To generate the required demand for Cooper Basin gas, the producers may need to lower the price of gas. This would require an even greater volume of new gas sales to offset the lost revenue from NSW/ACT markets. Given historical research that gas demand is relatively inelastic (see paragraphs 4.145 to 4.151), prices may need to fall significantly. It is unlikely that the producers would sacrifice gas sales to NSW/ACT on these terms.[93] The Council concludes from this analysis that the Cooper Basin producers do not have sufficient alternative markets to defeat a price rise on the MSP by diverting gas sales to South Australia.

7.182 As an additional observation, the Council notes NECG's claim that if the current MSP tariff was $0.43c per GJ (rather than the current price of $0.66 per GJ), the MSP would be equally constrained from profitably raising prices:

> *The analysis is not sensitive to the price used. If a figure of $0.43 G/J is used the gas required to make the price rise unprofitable under the 5% scenario only increases by 0.03 P/J* (NECG 2002, sub.19, App G, footnote 24).

7.183 The Council observes that if EAPL would be effectively constrained from profitably raising prices significantly above $0.43/GJ, it is difficult to explain why the current price is $0.66/GJ. In the Council's view, this raises considerable doubt as to the value of critical loss analysis in this instance. While the analysis finds that EAPL has no ability and incentive to raise tariffs above $0.43/GJ, current MSP tariffs are about 53% above that rate. In other words, the analysis is not credible in the light of current MSP pricing.

7.184 In discussions with the Council, NECG has agreed that there is a high level of uncertainty associated with the contribution that critical loss analysis can provide in this case.

7.185 The Council concludes that critical loss analysis does not provide evidence that the Cooper Basin producers can defeat monopoly pricing on the MSP by diverting gas sales into markets outside

93 Ordover and Lehr point out that gas producers will refuse to sell their gas to a particular market unless they earn the same return on the marginal unit of gas shipped to that market as they can earn on shipments to other locales (Ordover and Lehr 2001, p.13).

NSW/ACT. In particular, the Council considers that technical and commercial issues are likely to render the Queensland scenario implausible in the foreseeable future. While the South Australian scenario may become physically possible from about 2004, there is convincing evidence that the Cooper Basin producers could not divert sufficient gas sales into South Australian markets to constrain monopoly pricing on the MSP.

Ability of Cooper Basin producers to bargain jointly with MSP

7.186 The ability of the MSP to monopoly price transportation services may be constrained absent coverage – at least to some extent – by countervailing power among the South Australian Cooper Basin Unit Producers.

7.187 The MSP has no alternative use for its pipeline but to ship gas to NSW/ACT[94], and the Cooper Basin producers have no alternatives to the MSP for delivering gas to NSW/ACT. Ordover and Lehr describe this setting as one in which there is:

> *potentially bilateral market power (ie market power both on the sell and buy sides of the market)* (Ordover and Lehr 2001, p.16).

7.188 Potentially, this scenario creates incentives for joint bargaining between the MSP and the Cooper Basin producers.

7.189 The Council notes that current Cooper Basin production is under the control of a single consortium. Ordover and Lehr consider that:

> *Since this is the only gas that can use the MSP pipeline, it seems reasonable to presume that the consortium may have substantial bargaining power when negotiating with the MSP for pipeline services* (Ordover and Lehr 2001, p.17).

7.190 If an outcome of this market dynamic was collusion between the parties, it could manifest as significant barriers to entry in the upstream market.

7.191 NECG argue that collusion between the Cooper Basin producers and the MSP is theoretically possible but implausible in practice, because:

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94 Apart from gas shipped to Victoria via the Interconnect.

(a) collusion is in breach of ss.45, 47 and perhaps s.46 of the *Trade Practices Act*, which provides effective remedies.

(b) collusion would run the risk of reactivating the coverage process. To minimise the risk, collusion would need to be opaque – but this would make effective collusion difficult.

(c) collusion to restrict output would not serve the MSP's interests. Given that the MSP has excess capacity and low variable costs, there are commercial incentives to maximise throughput. In this sense, the MSP's interests are best served if upstream competition is promoted; higher volumes of gas and lower well-head gas prices would stimulate demand for pipeline services. Therefore upstream rents would need to be substantial to make collusion profitable.

7.192 The Council notes that collusion could manifest in a variety of rent sharing arrangements of benefit to both the MSP and the incumbent Cooper Basin producers. Collusion could be reflected in long-term contracts that inhibit upstream entry, either through above-cost pricing of transport services, or through other means of effectively foreclosing access to the MSP.[95] This would impose a barrier to potential new entrants in the Cooper Basin, weakening the competitive environment in the upstream gas sales market.

7.193 Ordover and Lehr considered that coverage could play a role in mitigating the risk of collusion:

> *To the extent that there is a danger of collusion among the incumbent gas producers and the MSP, coverage may lower entry barriers upstream by reducing the ability of the upstream incumbent gas producers to collusively foreclose access to the MSP... However, absent coverage, the consortium might be able to foreclose entry of new producers by signing a favorable long term contracts with the MSP* (Ordover and Lehr 2001, p.17, 18).

7.194 The Council considers that, absent coverage, there may be scope for collusive behaviour between the Cooper Basin producers and the MSP, which could adversely impact on competition in the upstream gas sales market. The Council observes that coverage could mitigate the risk of collusion by providing a right for third parties to access

95 It may be possible for parties to reach an agreement that effectively forecloses access without breaching the provisions of Part IV of the TPA.

spare capacity on the MSP at an efficient price set by an independent regulator.

7.195 While accepting the theoretical possibility of collusion, the Council has found no evidence of collusion between the MSP and the Cooper Basin producers. For this reason, the Council does not rely on the possibility of collusion in assessing the case for coverage of the MSP under criterion (a).

Conclusion: does upstream competition constrain MSP pricing?

7.196 In the upstream market, the MSP's ability to exert market power turns on whether the Cooper Basin producers have viable options to divert gas sales into other markets in the event of anti-competitive MSP pricing. The only viable alternative at present – the Moomba to Adelaide pipeline – is capacity constrained. While this may change from about 2004, it appears that South Australia's gas demand is not growing fast enough to absorb the sales diversions needed to constrain MSP pricing. Nor is there likely to be scope to divert gas sales into Queensland markets in the foreseeable future. Absent coverage, the MSP is therefore likely to have sufficient market power to charge monopoly tariffs for shipping Cooper Basin gas.

Downstream competition

7.197 The Tribunal has found that the EGP, in transporting Gippsland Basin gas to some NSW/ACT markets, has contributed to greater competition between sources of supply in downstream markets:

> *... it is not disputed that the construction and commissioning of the EGP has resulted in a not insignificant level of competition at the wholesale and retail levels for the sale of gas in NSW. Nor is it disputed that the construction of the EGP produced at least the environment for basin on basin competition. In and of itself, the construction and commissioning of the EGP has been pro-competitive.*
>
> *The competition between the pipelines serving the Sydney market has had flow-on effects into the market for gas in Sydney. This flow-on occurs because it is the delivered price of gas, comprising the wellhead price and the transmission charge, which determines the price of gas. The competition was evident in two ways. First, there was a reduction in the price of gas transmission services on the MSP in response to the (then) proposed opening of the EGP. There was also a price decrease on the AGLGN pipeline which connects to the MSP at Wilton,*

although there was disagreement about whether this resulted mainly from the proposed entry of EGP or the actions of the NSW regulator. Second, there were changes in the supply of gas between the Cooper and Gippsland Basins, with the latter now supplying a significant amount of gas into NSW which previously came from the Cooper Basin. The indirect effect of the fall in demand for Cooper Basin gas in NSW is that gas from that basin is now being sold into Victoria and being transported along the Interconnect. The pipeline and basin competition has also been associated with a reduction in the price of using the Interconnect through discounting of the reference tariff (Duke EGP decision 2001, paragraphs 81-82).

7.198 While competition had improved since the opening of the EGP, the Tribunal noted that criterion (a) turns on whether the opportunities and environment for competition in upstream/downstream markets would be enhanced if the EGP was covered under the National Gas Code *(Duke EGP decision 2001*, paragraph 83). In other words, it is not sufficient to demonstrate that the environment is now more competitive than it was in the past. The essential question is whether coverage would improve the competitive environment compared to conditions absent coverage. To the extent that existing market conditions are already effectively competitive, then the scope for an improved competitive position would be slight. However, where there is limited competition, it may be that there is scope for improvements to the competitive environment comparing conditions with and without coverage.

The nature of downstream competition

7.199 MSP transportation services acquire value to downstream customers by being bundled with gas (and in some cases, distribution and retail services). It is the price of this bundle that buyers compare when making choices between products (Ordover and Lehr 2001, p.9; *Duke EGP decision 2001*, paragraph 82). Thus, to the extent that downstream competition exists in the Sydney and Canberra markets, it is between Gippsland Basin gas (bundled with EGP haulage, distribution and retail services) and Cooper Basin gas (bundled with MSP haulage, distribution and retail services).

7.200 The Council notes that the MSP and EGP offer quite different services, which may limit scope for substitution. For example, if a party in Sydney has contracted to buy gas from the Cooper Basin producers, the MSP is the only means of shipping that gas. The EGP does not provide a substitute service for the shipment of gas between the Cooper Basin and Sydney. As the Energy Markets Reform Forum (representing Tomago Aluminium, OneSteel, Incitec, Amcor, BHP Billiton and Visy Paper, among others) points out:

> *Cooper Basin gas producers cannot use the EGP to transport gas to NSW* (EMRF 2001, sub.12, p.2).

7.201 In this sense, competition between the MSP and other pipelines (the EGP and Interconnect) is *derived* from competition between bundled products of delivered gas. While there are commercial imperatives for the bundles to compete with one another, it cannot be assumed that prices for each element of the respective bundles will be competed down to efficient cost. For example, if there are efficiency differences in gas production between basins, there may be scope for a pipeline shipping gas from a lower-cost basin to charge monopoly tariffs. In this scenario, downstream consumers do not receive the benefits of lower costs from the more efficient basin, and competition cannot be said to be effective.

7.202 In a submission to the Council on coverage of the EGP, Woodside pointed out that while construction of the EGP may have improved competition between gas basins, it should not be assumed that this competitive discipline will translate effectively to the pipelines transporting the gas:

> *It is insufficient to assert that the existence of alternative gas pipeline routes to Sydney, for example, will of itself provide an adequate degree of competition. The Eastern Gas Pipeline and Moomba to Sydney Pipeline do not compete in point to point transmission services, they merely have a common termination point, and run in parallel for a minor percentage of their respective lengths* (Woodside 2000, p.2).

7.203 Gas Advice (representing ACI, Amcor, Austral Bricks, CSR and others) argues that the notion of the EGP and MSP competing with one another is conceptually misleading:

> *The EGP cannot directly take business away from the Moomba to Sydney Pipeline. It is not simply a question of two pipelines competing in the same market. To increase its market share, the EGP must rely on Gippsland Basin producers increasing their production capacity and winning an increased share of the NSW gas market beyond the requirements of the foundation contracts of the EGP* (Gas Advice 2001, sub.5, p.9)

7.204 The notion that the MSP and EGP do not compete with one another in a direct sense is evident from a comparison of tariffs and tariff movements. Each pipeline has had one tariff movement since 2000:

(a) In June 2000, EAPL *reduced* the MSP tariff for shipping[96] gas from Moomba to Sydney, from 71¢/GJ to 66¢/GJ[97]. In January 2002, Duke Energy *raised* the EGP tariff for shipping gas from Longford to Sydney from its original rate of 86¢/GJ to 91¢/GJ.

(b) In June 2000, EAPL *reduced* the MSP tariff for shipping[98] gas from Moomba to Canberra, from 65¢/GJ to 60¢/GJ. In January 2002, Duke Energy *raised* the tariff for shipping gas from Longford to the offtake point of the EGP to Canberra pipeline, from 65¢/GJ to 69¢/GJ.

7.205 The Council notes that:

(a) the EGP tariff to Sydney is about 38% higher than the MSP tariff to Sydney;

(b) MSP and EGP tariffs have become more divergent since 2000; and

(c) the price differential could widen as EGP tariffs will escalate once again on 1 January 2003, with ongoing annual escalations, in accordance with a formula based on movements in the Consumer Price Index (Duke 2001b, p.5).[99]

These are not patterns one would expect to find between vigorously competing services.

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96 Firm transport at 100% load factor. All references to tariffs in ¢/GJ or $/GJ in this report are based on the same assumption. Firm transport means transport with the guarantee that the gas will be delivered on the day and at the time specified in the contract. 100% load factor means that the user uses all of the capacity booked by it for any given day or time

97 The prices quoted in this section are GST-exclusive, unless otherwise stated.

98 See footnote 96.

99 Unless MSP tariffs also rise. See paragraph 7.85 and footnote 80 .

How effective is downstream competition?

7.206 The MSP's ability to charge monopoly tariffs would be constrained if downstream competition is effective. The effectiveness of downstream competition depends on how feasible it is for NSW/ACT customers to switch to alternative sources of gas supply at a competitive price in the event of monopoly pricing on the MSP. This depends on a range of factors, including:

(a) the availability of natural gas in NSW/ACT markets from sources other than the Cooper Basin. This, in turn, depends on the volume of gas output from those sources, and available pipeline capacity to ship the gas.

(b) structural conditions in NSW/ACT markets, affecting opportunities for customers to switch from one source of gas supply to another.

Gas reserves and pipeline capacity

7.207 For downstream competition to be effective, there must at least be sufficient availability of natural gas from sources other than the Cooper Basin, and sufficient capacity on alternative pipelines to satisfy the requirements of consumers if monopoly tariffs are charged on the MSP.

7.208 The combination of adequate gas reserves and spare pipeline capacity would provide evidence that competition between the EGP and MSP may provide an effective constraint on the MSP's ability to exercise monopoly power in downstream markets:

> *If the competition for gas customers in NSW is intense because there is significant pipeline capacity that can be deployed to deliver gas to NSW, then MSP will not be able to overprice transport without risking a significant diminution in demand for Cooper Basin gas and thus for its own transportation services* (Ordover and Lehr 2001, p.18).

7.209 However, Ordover and Lehr also point out that peak capacity constraints need to be considered. Gas Advice argues that, while there is unused capacity on the MSP during non-winter months, there is little spare capacity during the winter months. Gas Advice argues that this limits scope for gas users to switch between suppliers (Gas Advice 2001, sub.5, p.13).

7.210 The Tribunal found in the *Duke EGP decision* that pipeline capacity constraints would not impede competition in NSW/ACT gas markets over the next 10-15 years. The Tribunal found that:

(a) while the Interconnect pipeline is currently capacity constrained, there will be sufficient MSP capacity to meet peak day demands at no cost until about 2006, and at a relatively low incremental cost after that date (*Duke EGP decision 2001*, paragraphs 22, 95).

(b) the existing capacity of the MSP, EGP and Interconnect in combination will not be exceeded until after 2014 (*Duke EGP decision 2001*, paragraphs 95).

(c) the MSP and the Interconnect between them could supply the whole of expected NSW/ACT demand until about 2008, subject to relatively low cost capacity expansions (*Duke EGP decision 2001*, paragraph 97).

7.211 The Tribunal also found that existing gas reserves, combined with likely future discoveries will be sufficient to meet projected gas demand in south-east Australia in the next 10 to 15 years:

> *... supplies of gas through Moomba are likely to be sufficient over the next 10 to 15 years as gas from the Cooper/Eromanga Basin will be supplemented by gas from basins to the north of Australia. There are reasonable grounds to expect that there will be sufficient gas supplies from and through Moomba to enable MSP to compete fully with EGP for gas sales to the NSW/ACT market over the next 10 to 15 years* (Duke EGP decision 2001, paragraph 103).

7.212 Ordover and Lehr formed a similar view:

> *There is evidence that every pipeline that competes for delivery of gas to the NSW/ACT markets is expected to have excess capacity during the next 10 to 15 years... (T)here appears to be substantial excess capacity and reserves available to deliver natural gas from the Cooper and Gippsland Basins into the retail markets in NSW and the ACT. Taken together, this evidence suggests that competition between the EGP and MSP pipelines may offer an effective constraint on the MSP's ability to exercise monopoly power* (Ordover and Lehr 2001, p.22).

7.213 The Council considers that gas reserves and pipeline capacity do not appear to create impediments to competition in downstream gas sales markets in NSW/ACT.

7.214 The Council observes, however, that the existence of gas reserves and pipeline capacity do not necessarily mean that customers are able to purchase their gas requirements, or that they can acquire access to spare pipeline capacity. For example, some parties have reported difficulties buying gas from the Cooper Basin producers. According to Gas Advice (representing ACI, Amcor, CSR and Austral Bricks, among others):

> *In the absence of coverage, production capacity constraints, particularly in the shorter term, may prevent competitive forces from applying a better discipline than would result from coverage... Examples of supply constraints include the recent lack of additional supply capacity being made available from Moomba by the Cooper Basin producers.* (Gas Advice 2001, sub.5, p.8)

7.215 Claims have also been made that pipeline access is difficult to acquire (see paragraphs 7.235 to 7.242).

7.216 The Council notes that if customers are unable to buy gas and/or pipeline access, any potential for downstream competition would be frustrated.

7.217 While the availability of gas and pipeline access are necessary pre-conditions to downstream competition, they are not sufficient in themselves to ensure that downstream competition will be *effective*. Structural conditions of supply and demand in downstream markets need to be examined to assess the extent to which competition is (or is likely to become) effective. The Council now turns to this matter.

7.218 The Council begins by focusing on the Sydney and Canberra markets. This is followed by separate consideration (paragraphs 7.293 to 7.301) of regional markets.

Regulatory and technical barriers to entry

7.219 The opening of the EGP created new gas supply options in some regions of NSW from 2000 (and in the ACT from July 2002). In addition, the introduction of full retail contestability in January 2002 in NSW and the ACT has removed regulatory and technical barriers that previously restricted the ability of small customers to change their gas supplier. There are no longer regulatory barriers to gas users contracting directly for gas supply with a gas producer and negotiating access to gas pipelines to ship the gas. The NSW Government has informed the Council that outstanding technical issues that had delayed the practical implementation of full retail contestability have now been addressed.

7.220 Against this background, there are no regulatory or technical barriers that would prevent a gas user in NSW/ACT from switching from one source of gas supply to another. In this sense, effective competition in downstream gas sales markets is now more feasible than it was prior to 2002.

7.221 However, many gas users regard the market as highly immature. Based on its experience in seeking alternate gas supplies as one of the largest gas users in NSW, Incitec considered that:

> *…EAPL has, and will continue to have, substantial market power in gas transportation to the Sydney market. The Sydney/NSW market is very concentrated. Downstream parties related to EAPL have a substantial proportion of the market... (A)ssociate contracts between related parties are very substantial and some are for durations of up to 10 years. The ability to offer prices which are lower than competitors vertically across related businesses can confer pricing advantage and can present high barriers to entry and expansion* (Incitec 2001, sub.10, p.12)

7.222 Transmission pipeliners argue that downstream competition needs to be viewed as an evolving process. According to EAPL:

> *The downstream market for gas in NSW and ACT became fully contestable in January 2002. The full impact of this will only become evident over time but it is likely to enhance the pro-competitive effects already noted by the Tribunal based on evidence from 1999.* (EAPL 2002, sub.19, p.17)

7.223 Duke agrees that while the market is shifting towards greater competition, it is not yet effectively competitive:

> *Australia has made significant progress in the development of a competitive market, but with the real developments having only taken place since 1998, clearly, it is still early days. Competition in the Australian-dependent market for gas sales cannot, nor could anyone sensibly expect it to, instantly move from a position of emerging deregulation to a level of maturity reflecting pricing at 'efficient-cost pricing outcomes' (based on a Code analogue) as if the market was enormously mature. Such a market would be characterised by many participants engaging in commercial behaviour reflecting the availability of a wide variety of financial instruments and the presence of a large volume of diverse transactions.* (Duke 2002, sub.21, p.3)

Commercial arrangements, including long-term contracts

7.224 Gas Advice argues that, despite regulatory reform and the construction of the EGP, the ability of gas users to switch suppliers remains constrained by commercial arrangements in the downstream market:

> *... the realities of commercial arrangements – often long term – between parties do not allow for substantial proportions of the market to move from one supplier to the other. A whole range of issues may prevent or limit such switching:*
>
> - *available upstream production capacity;*
> - *available pipeline transmission capacity;*
> - *timeframe for availability of such capacities;*
> - *supply reliability / interruptibility; and*
> - *capacity priority arrangements.*
>
> *The issues in each of the above bullet points are critical and relevant issues* ***today*** *in the supply of gas into the NSW market* (Gas Advice 2001, sub.5, p.6)

7.225 One of the constraints raised by Gas Advice is the prevalence of long-term contracts. The use of long term contracts in upstream and downstream gas sales markets is often cited as a factor that may limit competition between alternative sources of supply.

7.226 Incitec cites its own position as an example of the inflexibilities imposed by contractual arrangements.

> *Incitec agrees with the argument that gas users' ability to switch between suppliers of both gas and gas transportation services are limited by contractual arrangements. For example, Incitec's gas supply is contracted until 1 January 2006* (Incitec 2001, sub.10, p.9).

7.227 Santos also argues that long-term contracts pose a genuine barrier to effective competition:

> *Santos believes that whilst long term contracts for gas purchasing exist from particular producers the degree of flexibility that is available on which pipeline to use for those purchases is limited. Inter Basin competition between sources of gas exists and will increasingly influence the market. But for at least the next ten years, if coverage on this gas pipeline were*

revoked, it would provide the Australian Pipeline Trust with the ability to extract monopoly rents from usage of the line (Santos 2001, sub.4, p.3).

7.228 EAPL argues that long-term contracts do not pose a significant barrier to competition:

...any party which entered into a supply contract over the last year or more did so with knowledge of their ability and opportunity to contract supply from alternate producers, pipelines and retailers. The fact that a particular end-customer's ability to switch between suppliers is constrained because that end-customer has voluntarily entered into a long term contract fundamentally misconstrues the competitive benefits that customers have, and will, receive. The proper measure of these benefits does not depend on the ability of customers to switch at any point in time, but on their potential ability to switch at the time they negotiate their contract (EAPL 2001, sub.13, p.4-5).

7.229 EAPL has also argued that the ability of an individual to change supplier is not the critical indicator of effective competition:

.. it is the market dynamics, not the freedom of specific individuals to switch at any point in time, that is important. The more relevant question is whether there are enough potential switchers over the long run to discipline pipeline behaviour. If there are, then contracts will reflect that competition and provide competitive benefits over the contract life to users (EAPL 2001, sub.6, p.13).

7.230 Ordover and Lehr consider that concerns that long-term contracts impede competition may be overstated because:

(a) a typical contract is relatively short compared to the horizon of entry decisions into upstream production or downstream retail markets;

(b) *ex ante* anticipation of future pricing behaviour ought to be reflected in current long term contracts. Thus, dynamic competition among pipelines in the market for long-term contracts should constrain current pricing;

(c) the ability of entrants to pre-contract for demand prior to investing lessens risk, which may lessen impediments to new entry (Ordover and Lehr 2001, pp.20-21).

7.231 Nor was the Tribunal convinced that long-term contracts are a significant barrier to competition:

> *... these contracts restrict the responses that purchasers of gas can make in response to price competition by pipelines. However, even when they are very long term (15 to 30 years), the contracts are not completely inflexible, eg the contracts can include price review clauses which are triggered by the price of other sources of gas. Long term contracts are not the only type of supply contract, and some evidence was given that contract periods with gas producers are becoming shorter (10 years) and there are short term contracts (5 years and less) in secondary and retail/wholesale markets. The contract between the Cooper Basin producers and AGL, the main user of the MSP, concludes in 2006 and negotiations have already commenced with producers. In response to the December 2000 ACCC Draft Decision on MSP tariffs (which suggested a reduction in the order of 40 per cent), Duke also indicated that it had commenced negotiations with the Gippsland producers for a reduction in the wellhead price of gas to enable gas from that basin to remain competitive with the gas from the Cooper Basin. When the Kipper field in Bass Strait comes on stream, expected in 2005, more competition will occur in the upstream market* (Duke EGP decision 2001, paragraph 104).

7.232 One of the factors cited by the Tribunal is that contracts can include price review clauses that are triggered by price movements for other sources of gas. Gas Advice argues that this fails to take account of the complexities of activating such a price review clause:

> *... no investigation has been made of the current production capacities and the ability of producers to respond in due time to a request for a price to a customer who wants to test the availability of terms and conditions of supply from alternative sources and of the possible differentiation as to interruptibility and other terms which would attract a customer form one source to another* (Gas Advice 2001, sub.5, p.8).

7.233 While long-term contracts are a matter of concern among many parties, the Council notes that the availability of short-term contracts may also be an issue. For example, EAPL has pointed out that the MSP requires a minimum term of one year for its standard firm capacity service (EAPL 2001, sub.13, p.4). The Council notes that a refusal to deal in short-term arrangements (of less than a year) may be a potential barrier to competition. This may become a critical issue as spot markets continue to develop (as has occurred in Victoria). The Council observes however, that a minimum term of one year is not unusual among regulated transmission pipelines (ACCC 2001b, p.13).

7.234 The Council agrees with the findings of the Tribunal, and the views of Ordover and Lehr, that long-term contracts are not a significant barrier to downstream competition. Noting the views of market participants, the Council observes, however, that the contractual framework for gas purchase, transmission, distribution and sale to end users in NSW/ACT markets is complex; with medium to long-term contracts common and significant take or pay components a feature. For example, a downstream gas seller wishing to switch from the MSP to the EGP would also face the necessity of switching sources of gas supply between the Cooper Basin and Gippsland Basin – and the need to address gas availability and contractual issues. These issues may make it difficult for gas customers to move actively between sources of gas supply in response to price changes.

Is access available?

7.235 While the environment for downstream competition appears to have improved since 2000, the ability of third parties to gain access to gas pipeline services remains critical to effective competition. A number of parties assert that it remains difficult for third parties to acquire access to the MSP, despite the fact that the pipeline operates below full capacity. Such assertions raise questions about the feasibility of effective downstream competition.

7.236 The Energy Users Association of Australia (**EUAA**, representing dozens of parties, including ACI, Alcoa, Comalco and ExxonMobil)) claims that major customers in the Sydney market have experienced 'considerable difficulty' in seeking to secure alternative gas supplies. They consider that this is due to the paucity of suppliers being able to gain access to capacity on the MSP Mainline. As a consequence, competition in the supply of gas has been less than effective (EUAA 2001, sub. 7, p. 3).

7.237 Incitec states that access to the MSP is more difficult to acquire than access to the EGP:

> *... the EAPL pipeline has no history of practical third party access arrangements. AGLWG has the priority access via the Gas Transportation Deed which contracts the main bulk of EAPL's available capacity to AGLWG. This contracted arrangement applies until 31 December 2016. On the other hand, EGP has an open access regime with no discriminatory pricing* (Incitec 2001, sub.10, p.7).

7.238 EAPL disputes these assertions, stating that it "has no records of any person having being unable to acquire access to capacity on the MSP." (sub.19, p.5) EAPL also states that it:

> *is not aware of and can find no record of having received a request for access from a number of the parties who have suggested they have been unable to obtain access* (EAPL 2001, sub.13, p.3).

7.239 EAPL has informed the Council that the MSP currently has contracts with three parties other than AGL (EAPL 2001, sub. 13, p.3). The parties are: Origin Energy, Duke Energy and Energex (EAPL 2001b, p.2). **[confidential information]**of expected deliveries on the MSP in 2002 is expected to be shipped for AGLWG (EAPL 2002, p.4).

7.240 The Council notes that the provisions of the Gas Transportation Deed appear to limit scope for third party access to the MSP. Under the Deed, **[confidential information]**of the MSP's current installed capacity (172 PJ/a) is reserved for AGLWG in 2002, a wholly owned subsidiary of AGL. The reservation rate **[confidential information]** by 2006, and is set at about 34% from 2007 to 2016 (see paragraphs 7.599 to 7.600 of this report).

7.241 **[confidential information]**. [100]

7.242 The extent of reserved capacity for AGLWG may also pose a barrier to new entry in the downstream gas sales market. The magnitude of this barrier depends in part on whether downstream customers are able to purchase gas from the Gippsland Basin producers at a competitive price and gain access to the EGP.[101]

Indicators of effective downstream competition

7.243 The Council has noted agreement among most parties that the development of downstream competition in NSW/ACT gas sales markets is an evolving process, with a considerable way to go. Below, the Council examines indicators of the competitive environment in

100 **[confidential information]**. NSW/ACT gas demand is forecast at about 159.1 PJ in 2006 (ACCC 2000b, p.91).

101 The Council further considers the Gas Transportation Deed in the context of vertical leveraging issues (paragraphs 7.593 – 7.616 of this report).

those markets, focussing on demand characteristics and observed market behaviour. The Council considers evidence on:

(a) cross-price elasticity of demand between sources of supply;

(b) rivalrous behaviour between suppliers, including evidence of price movements and innovative marketing;

(c) changes in supply and transport arrangements, including direct contracting between gas producers and major customers; and third party pipeline access; and

(d) trends in aggregation and retailing of natural gas.

7.244 Another indicator of the competitive environment in downstream markets is the extent to which pricing outcomes for gas pipeline services reflect long-run economic cost. If pipeline tariffs deviate materially from long-run cost, it demonstrates that the owner/operator is able to exert market power in at least one dependent market. The Council gives separate consideration to this matter in s 7.315 to 7.405 of this report.

(a) Cross-price elasticity of demand

7.245 Empirically, the ability of alternative sources of supply to offer effective competition would be supported by a finding that there is a high cross-price elasticity of demand between services of the MSP and other pipelines, or (more accurately) between gas delivered by the MSP from the Cooper Basin and alternative sources of gas supply in NSW/ACT markets.[102] According to Ordover and Lehr:

> *If the ability of end users to shift demand to other sources of natural gas away from MSP is... small at a "competitive" price,[103] then a price increase above that level would likely be profitable for the MSP* (Ordover and Lehr 2001, p.20).

7.246 An estimate of a high cross-price elasticity of demand between pipelines serving NSW/ACT markets was cited in the *Duke EGP*

102 The Council explains at paragraph 7.199 that to the extent that downstream competition exists in Sydney and Canberra gas sales markets, it is between different sources of delivered gas (that is, gas bundled with pipeline services).

103 "Here, by a competitive price, we mean a price that earns MSP a normal rate of return (corrected for risk) and no more. We are not implying that this is the proper price benchmark against which prices in other industries must be gauged."

decision as evidence that the EGP lacks market power (*Duke EGP decision 2001*, paragraphs 106-108). A number of parties now argue that this evidence can be extrapolated to reach a finding that the MSP also lacks market power.

7.247 According to the AGA:

> *In the* EGP decision *the Tribunal noted that these cross-price elasticities were an important factor in determining the scope for possible anti-competitive conduct. The Tribunal noted quantitative evidence that the cross-price elasticity of supply between the EGP and the Interconnect was approximately two, that is, that a 10 per cent increase in prices in one pipeline could lead to an increase in the demand for services of the alternative of 20 per cent. A similar cross-price elasticity is likely to exist between the EGP and MSP, implying that strong competition between the pipelines exists.* (AGA 2001, sub. 8, pp.4-5)

7.248 The *Duke EGP decision* referred to a cross-price elasticity of demand between the EGP and Interconnect of '2'. This would suggest that a price change would result in a high rate of substitution between pipelines. The Tribunal said:

> *The quantitative analysis of price increases by EGP undertaken by Mr Ergas ("SSNIP") implied a cross price elasticity of two between the EGP and the Interconnect; this was supported by evidence about the actual price sensitivity of gas purchasers in the marketplace. The "SSNIP" analysis tests substitutability by asking whether a firm would gain or lose by attempting to impose a small but significant, non-transitory increase in price on its own product or service.*
>
> *A cross price elasticity of two is a high figure. It means that a 10 per cent increase in price will result in an increase in the demand for the alternative service(s) of 20 per cent* (Duke EGP decision 2001, paragraphs 106-107).

7.249 The Council understands from discussions with Mr Henry Ergas (of NECG) that the figure cited was not the result of econometric modelling, due to the difficulty of obtaining data on normal, unfettered market behaviour. Instead, the estimate was derived from a "SSNIP" analysis conducted by NECG in relation to the EGP and Interconnect pipelines (*Duke EGP decision 2001*, paragraph 106). Mr Ergas has agreed that the analysis could not be relied on to derive a precise calculation of relevant elasticities.

7.250 Ordover and Lehr said:

> *We have seen the comments made in the Tribunal's decision in relation to the EGP on cross-price elasticities and the evidence of Mr. Ergas from which it appears that comment is derived. In our opinion, the material does not provide a sufficiently reliable empirical basis upon which to determine quantitative magnitudes of the pertinent cross-price elasticities* (Ordover and Lehr 2001, p.20 footnote 39).

7.251 The SSNIP analysis that a relatively small price rise by the EGP could be defeated by the Interconnect also raises questions as to why the EGP found it profitable to increase tariffs in 2002; ie EGP and Interconnect tariffs are diverging. Further, it appears that the EGP did not regard the MSP as a constraint on its ability to raise prices at current MSP prices.[104] The Council notes the possibility that the EGP could raise its tariffs without raising the price of delivered Gippsland Basin gas in Sydney, if Gippsland Basin gas prices were falling. However, there is no evidence that EGP tariffs are rising for this reason. Annual price rises for EGP services are predetermined in the EGP's firm forward haulage service contract terms sheet (Duke Energy 2001b). It is likely, therefore, that annual escalations in EGP tariffs are weakening whatever discipline the EGP may previously have applied to MSP tariffs.

7.252 The Council reiterates that the estimate cited by the Tribunal referred to the cross-price elasticity of demand between the EGP and the Interconnect. Even if the estimate was accurate with regard to substitution between the EGP and Interconnect, there is no basis for assuming that the same estimate would apply to the cross-price elasticity of demand between the MSP and the EGP, given that the MSP and EGP provide different services.

7.253 There are similarities between the services of the EGP and the Interconnect that do not extend to the MSP. Both the Interconnect and EGP provide a service between Longford and Sydney (and between various locations along their respective routes).[105] Thus, a customer may be able to switch between the EGP and Interconnect without also having to switch between gas producers. Given that the

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104 The *Duke EGP decision* was made in the context of the MSP being a covered pipeline.

105 When the Council refers to the Interconnect as providing a service between Longford and Sydney, it is using shorthand to describe a service provided by a combination of pipelines between Longford and Sydney, incorporating: the Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline.

MSP provides a different service to the EGP, the cross-price elasticity between the MSP and the EGP is likely to be lower than between the EGP and Interconnect.

7.254 Regarding the cross-price elasticity of demand between the MSP and other pipelines, Ordover and Lehr observed that:

> *While it seems plausible that the cross-elasticities are high, we are unaware of any empirical studies that provide a firm basis for gauging the size of the relevant cross-price elasticities...* (Ordover and Lehr 2001, p.20).

7.255 The Council considers it likely that construction of the EGP has improved substitution possibilities between gas basins.[106] The Council accepts Ordover and Lehr's view that, despite a lack of empirical evidence on this matter, cross-price elasticities between sources of gas supply to NSW/ACT are plausibly high at current price levels.

7.256 However, as the Council explains at paragraphs 7.542 to 7.549, cross-price elasticity estimates at current prices are misleading in the presence of monopoly pricing. In particular, if cross-price elasticity estimates are measured at monopoly prices, it cannot be assumed that a high cross-price elasticity is evidence of effective competition. This is because the elasticity of demand for a monopolist rises as its pricing increases above economic cost. Thus, a monopolist pricing at the profit-maximising point will have an elasticity of demand that appears quite 'competitive' – and is likely to exceed one. The Council provides evidence at paragraphs 7.315 to 7.405 that current MSP tariffs are likely to reflect monopoly pricing.

7.257 The Council concludes that it is difficult to assess the relevant cross-price elasticities, due to the lack of empirical evidence, and because any available data would be difficult to interpret in the presence of monopoly pricing. As explained at paragraphs 7.542 to 7.549, while the cross-price elasticities of demand between the MSP and other pipelines may be high at current price levels, they are not likely to be substantially above 1.0 at competitive price levels.

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106 This does not indicate that downstream competition is effective; that is, it does not suggest that monopoly rents have been competed away.

(b) *Rivalrous behaviour between suppliers*

Tariff movements

7.258 EAPL cites recent MSP tariff movements as evidence of competition for the supply of gas to downstream markets. In particular, EAPL point out that the MSP Moomba to Sydney tariff fell from $0.71/GJ to $0.66/GJ (excluding GST) in July 2000.

7.259 This was the first MSP tariff movement since 1995 (EAPL 2001, sub.6, p.4), and no further price movements have occurred since July 2000. It is unclear whether the July 2000 reduction was a response to competitive discipline from the EGP, or a strategic move to coincide with regulatory processes on the MSP conducted by the ACCC.

7.260 The MSP interconnects with the AGLGN distribution network at Horsley Park via the AGLGN transmission pipeline that connects to the MSP at Wilton. The AGLGN tariff for shipping gas from Wilton to Horsley Park (which is also the endpoint of the EGP) fell from 23.5¢/GJ to a regulated tariff of 3.71¢/GJ under an IPART decision in July 2000. In light of the material which the Council has seen, it considers that the price change reflects a blend of regulatory activity and a response by the service provider to bypass.[107]

7.261 The notion of vigorous downstream competition is not supported by recent EGP tariff movements. While MSP tariffs fell in 2000, EGP increased its tariffs in 2002. For example, the MSP tariff to Sydney was reduced from 71¢/GJ to 66¢/GJ, while the EGP tariff for shipping gas to Sydney was raised from 86¢/GJ to 91¢/GJ. Similar trends are apparent for pipeline services to Canberra. EGP tariffs will again rise in January 2003, which is likely to further weaken whatever discipline the EGP may previously have applied to MSP tariffs (see footnote 80).

7.262 The opening of an interconnector between the EGP and the ACT in July 2002 introduced a second source of gas supply to the ACT. The Independent Competition and Regulatory Commission (ICRC), the ACT gas access regulator, has informed the Council that there is no evidence at present of enhanced price competition between sources of

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107 The Wilton to Horsley park section of the AGLGN pipeline was bypassed when the EGP was extended to Horsley Park.

gas supply. The Council notes that the EGP tariff from Longford to the offtake point of the Canberra interconnector was increased on 1 January 2002 from $0.65/GJ to $0.69/GJ (excluding GST). The Council understands from ICRC that the principal benefit of the EGP interconnector is enhanced security of gas supply for the ACT. This may also reduce the potential for seasonal price spikes.

Innovative marketing

7.263 The Council notes the temporary offer of a new service by the EGP in 2002. EAPL argues that this is further evidence of greater depth emerging in competition to supply downstream markets in NSW. The service, called FRC Forward Haulage service (**FRC service**), was for transport from Longford to Port Kembla and/or Horsely Park, at a published starting tariff of $0.62/GJ, escalating at 100% of CPI effective 1 January each year. This compares with the standard tariff of $0.91/GJ.

7.264 The FRC service was required to commence no later than 1 July 2002 and terminate on 31 December 2004. The offer ceased to be available after 1 July 2002. The Council understands that the FRC service had a lower priority rating than EGP Firm Forward haulage; for example, there is less tolerance on overruns and imbalances.

7.265 EAPL informed the Council that it would compete fiercely should a party consider the EGP offer. The Council requested that EAPL inform it of any action the company may take in response to the EGP offer. EAPL informed the Council in August 2002 that it had not received an inquiry to match the EGP offer.

7.266 Duke Energy International (**Duke**) informs the Council that the FRC service was made available to the market generally, via posting to Duke's web site as well as an email broadcast to users and prospective users. Duke has informed the Council that the number of customers that have taken up the new service is not available for disclosure (Duke 2002b).

7.267 The Council notes that the FRC Forward Haulage service was available for only a limited time, and is not available at the time of this recommendation. The temporary nature of the offer, and the lack of available information on take-up, makes it difficult to draw conclusions on the competitive environment in downstream markets.

(c) Changes in supply arrangements

7.268 A competitive downstream gas sales market is likely to exhibit some movements in supply and transport arrangements, including trends towards direct contracting between gas producers and major customers; and third party shipper contracts on gas pipelines serving downstream markets.

7.269 The Council notes that there has been some market churn since the opening of the EGP. The Tribunal cited evidence of market churn in the *Duke EGP decision*, noting that the EGP now supplies “a significant amount of gas into NSW which previously came from the Cooper Basin,” and that some displaced gas sales from the Cooper Basin are now being sold into Victoria via the Interconnect. This was also associated with discounts to the Interconnect reference tariff.

7.270 According to EAPL:

> *To date, the EGP has won approximately 20 PJ/a from the MSP. This volume of gas is significant in relation to the MSP's overall demand level prior to that event, being approximately 120 PJ/a. The loss of this volume has significantly added to the existing spare capacity on the MSP* (EAPL 2001, sub.6, p.15).

7.271 The ACCC has provided further details of these developments:

> *Duke Energy has reportedly signed two long term gas contracts which together commit it to supply approximately 20 PJ per annum – one with BHP Steel for all of its NSW sites and the other with Sithe Energies at Smithfield. In addition, the Victorian-based energy retailer CitiPower is reported to have contracted with Duke Energy for on-sale of gas for three years in Sydney. Two NSW government-owned power companies, Energy Australia and Integral Energy are also reported to have contracted with Duke Energy* (ACCC 2000b, p.98).

7.272 The Council notes that Esso/BHP Petroleum signed a gas transportation agreement with Duke Energy in 1998 coincident with the contract for the sale of the EGP project by BHP Petroleum and Westcoast to Duke Energy. Under the gas transportation agreement, Esso and BHP Petroleum contracted for 80 TJ/d capacity on the EGP (about 29 PJ/a at 100% load factor, or 23 PJ/a at 80% load factor). EAPL cites these trends in gas supply arrangements to downstream markets as an indicator of competition:

The fact that the EGP was able to take away about 20% of sales within a short period is irrefutable evidence of its ability to compete and of its doing so (EAPL 2002, sub.19, p.7).

7.273 Gas Advice (representing ACI, Amcor, Austral Bricks, CSR and others) take a contrary view:

Rather than taking the view that there has been a significant switch from Cooper Basin gas to Gippsland Basin gas into NSW since the commissioning of the EGP around September 2000, it could be argued that there has been limited market penetration by EGP and the Gippsland Basin producers in the NSW market. Whilst the EGP is currently estimated to be supplying around 25 PJ per annum out of a total demand of around 110 PJ per annum, there have been very limited numbers of gas users which have switched from Cooper Basin to Gippsland Basin supply sources. Putting aside the contracted loads for BHP and One Steel at Port Kembla and the Sithe cogeneration plant at Smithfield (approximately 20 PJ per annum and which were foundation customers used to underwrite the development), only an estimated 5 PJ of additional load has since transferred to be supplied through the EGP rather than the Moomba to Sydney Pipeline (Gas Advice 2001, sub.5, p.7).

7.274 In other words, EAPL makes an assumption that all loads carried on the EGP would otherwise have been carried on the MSP. Gas Advice argues that apart from foundation customers buying gas under long-term contracts for new development projects, few users have actually *switched* to gas supplied by the EGP.

7.275 Nonetheless, the Council accepts that there is evidence of some degree of churn. In this sense, it is apparent that the EGP has provided potential for some Sydney customers to switch their supply arrangements between the Cooper Basin producers and the Gippsland Basin producers.

7.276 The ACT's Independent Competition and Regulatory Commission informed the Council in July 2002 that as yet, there are no indications of customer switching between sources of gas supply in the ACT. ICRC informed the Council that there had been no overt promotion activity regarding the opening of an interconnector pipeline with the EGP, and that there had been no inquiries about new entrants to the market.

Unbundling

7.277 It is understood that at present few large users have unbundled their gas and delivery requirements or negotiated delivered gas supply contracts with unbundled price components. While this may reflect that gas users have a preference for bundling, it may also reflect limited opportunities to unbundle.

7.278 Incitec, the largest gas user in NSW, has negotiated a contract for delivery of gas to Wilton, and a separate contract with AGL for delivery of that gas from Wilton to its plant in Newcastle north of Sydney. Another major user has negotiated two contracts for delivery of gas to its site: a bundled gas and delivery contract for the supply of gas to Wilton; and a distribution contract with AGLGN (or an associated party) for delivery of the gas from Wilton to its plant. Four other major users are understood to have unbundled gas and delivery contracts. Other major users continue to hold bundled gas and delivery contracts for delivery of gas to their factory door.

7.279 In other words, to date there is only limited movement in NSW/ACT markets towards gas customers contracting directly with gas producers and (separately) with gas pipeline owners to ship gas to downstream markets. This finding appears to be borne out by facts noted elsewhere that only three parties independent of AGL (the traditional wholesale supplier) currently ship gas on the MSP. In total, the independent parties are expected to ship about **[confidential information]**of gas delivered by the MSP in 2002 (EAPL 2002, p.4).

(d) Competition in the gas retail sector

7.280 An assessment of competition in the downstream gas sales market must consider the emergence of competition between gas retailers to supply customers.

7.281 Duke argue that competition between gas retailers is rapidly deepening:

> *The development of this competitive market is relatively recent and dates, realistically, from 1998 at the earliest. Nevertheless, full retail contestability has now emerged. Retailers are seeking to offer what is anecdotally called the 'dual fuel' option. There is substitution between gas and electricity at some levels and retailers/traders in electricity and gas both seek to be in a*

> *position to offer a gas or electricity fuel option* (Duke 2002, sub.21, p.6).

7.282 There are few retailers in NSW or the ACT that are independent of the distributors in those places. The independent retailers hold only a small share of retail gas sales to both large and small users (IPART 2001b, p.9, ICRC 2001, p.5).

7.283 Prior to full retail contestability, AGL Retail Energy Limited (**AGLRE)** supplied 96% of NSW customers using less than 10 TJ/a. In particular, it supplied all tariff users other than those in Wagga Wagga (supplied by Country Energy with gas supplied by the MSP), Cooma (supplied by Country Energy with gas supplied by the EGP), and Albury (supplied by Envestra with gas supplied by the Victorian transmission network) (AGA 2001, pp.36-37).

7.284 The introduction of full retail contestability in January 2002 has enhanced the potential for competition in gas retailing. In April 2002, the rate of customer transfer was about 1.96% on an annualised basis (Gas Market Company 2002). This low rate is likely to increase as customer awareness of contestability deepens, but suggests that the market remains in a transitional state at present.

7.285 Some parties consider that perceptions of enhanced competition are illusory at this stage. For example, BHP Billiton and Incitec point out that, despite the issuing of new licenses:

> *(t)here are only a few active gas retailers in the NSW market, with a large incumbent retailer* (BHP Billiton and Incitec 2002, sub.23, p.20).

7.286 As of July 2002, 14 parties were licensed to sell gas in NSW (IPART 2002). IPART informs the Council that, many of these parties are not active in the NSW market. A number of others supply only their own large sites, or are active only in parts of regional NSW.

7.287 IPART indicated to the Council that, in July 2002, Energy Australia was the only active gas retailer in Sydney independent of AGL (the other retailers were AGL Energy Sales and Marketing Ltd and AGL Retail Energy Limited). In addition, some very large users (such as Incitec) make their own supply arrangements. While there are no figures on the share of sales to contract customers held by each of the active retailers, IPART considers that AGLES&M retains the majority of sales to contract customers (IPART 2001b, p.9).

7.288 In the ACT, there are currently two licensed retailers: ActewAGL and Energex. A third retail licensee, Energy Australia, let its retail licence in the ACT lapse in 2000. The ACT's Independent Competition and Regulatory Commission informed the Council in July 2002 that at present ActewAGL is the only retailer active in the ACT, holding 100% of retail sales of natural gas to both large and small customers (ICRC 2001, p.5). ActewAGL is a 50-50 joint venture of Actew (publicly owned) and AGL.

7.289 IPART reported in 2001 that downstream competition in NSW was in a fledgling state and was likely to remain so for some time:

> *...the Tribunal considers that effective competition is likely to take some time to develop due to AGLRE's market dominance. The extent of competition, the likely impact on prices and services, and the likely delivery time of the benefits from competition cannot be predicted with any degree of certainty (IPART 2001a, p.7).*

7.290 Elsewhere, IPART cited a number of factors that may be hampering the development of effective competition, once again noting that the timeframe for improvement is unclear:

> *The Tribunal is of the view that competition in the tariff market is likely to develop over time. Current structural impediments, such as limited alternative gas supply sources, the lack of business rules and systems to support contestability, economies of scale and contestability costs, are expected to diminish over the medium term. Even so, the extent of competition, the likely impact on prices and services, and the likely delivery time of the benefits from competition can not be predicted with any degree of certainty.*
>
> *The experience in the UK gas industry suggests that effective competition can be achieved once markets become contestable and that the benefits of competition are considerable. While this provides some encouragement, the Tribunal accepts that the UK and NSW markets are substantially different and that the positive UK experience may not be replicated fully in NSW* (IPART 2000a, p.34).

7.291 In December 2000, the NSW Government reported that the risk of monopoly pricing in retail markets would remain potent for some time:

> *It will take time for retail competition in gas to take full effect. In the meantime, retailers could exercise undue market power in a way that could lead to monopoly pricing behaviour (NSW Ministry of Energy and Utilities 2000b, p.16).*

7.292 The Council notes the cautionary views of IPART and the NSW Government on the emergence of effective retail competition. In particular, the Council notes concerns over market power enjoyed by the traditional incumbents. The Council concludes that while some competition is emerging, there is no basis for accepting that the market is moving rapidly towards effective competition.

Downstream markets along the route of the MSP

7.293 The EAPL revocation application relates to the MSP Mainline from Moomba to Sydney, and the Canberra Lateral. While Sydney and Canberra are served by both the MSP and EGP, destinations along the route of the MSP Mainline and Canberra Lateral are serviced only by the MSP. For these regional markets, there are no alternative gas supply options and the MSP is a monopoly provider of pipeline services.

7.294 According to Incitec:

> *there are some regional markets in NSW (e.g. Bathurst and Orange) which are not served or likely to be served by EGP or any other competing pipeline for the foreseeable future. Whilst EAPL has not sought revocation of coverage for the laterals serving these markets, it is likely that EAPL's ability to exercise market power in these regional markets through the MSP Mainline will continue* (Incitec 2001, sub.10, p.7).

7.295 In addition, while laterals other than the Canberra Lateral are not subject to the EAPL application, customers wishing to ship gas from Moomba to points along the laterals would require access to both the lateral in question, as well as the MSP Mainline. For regional markets served by these laterals, the MSP is the sole provider of pipeline services.

7.296 EAPL agrees that it owns the only pipelines serving intermediate regional markets such as Bathurst and Orange, but argues that monopoly pricing is not a risk because:

> *1. while the portion of the Mainline from Moomba to each lateral offtake will be unregulated if coverage of the MSP is revoked, EAPL's intention to continue its current policy of distance based pricing, linked to the price for transport from Moomba to Sydney means that price reductions driven by Sydney market dynamics will be translated into price reductions for customers at intermediate locations;*

> *2. revocation of coverage is not sought for the lateral pipelines serving these regional markets; and*
>
> *3. if at a later time it is believed that EAPL is not honouring this commitment, then an application can be made for coverage* (EAPL 2001, sub.6, p.11).

7.297 The Council notes EAPL's stated intention to pursue pricing that does not discriminate against regional customers. However, the Council cannot rely on a stated intention as conclusive evidence that this position will be maintained if coverage of the MSP is revoked. It is therefore appropriate for the Council to have regard to the incentives facing the pipeline owner.

7.298 In the *Duke EGP decision*, the Tribunal was not convinced that access was necessary to promote competition in regional markets south of Canberra, despite the fact that the EGP was the only provider of pipeline services to those areas. The Tribunal found that monopoly behaviour was unlikely due to the publication of non-discriminatory tariffs, and commercial incentives for the EGP to develop new markets by attracting customers away from other energy sources (*Duke EGP decision 2001*, paragraph 132).

7.299 The Council notes that the circumstances for regional markets along the route of the MSP differ from those served by the EGP. In particular, regional markets served by the EGP were not previously served by *any* pipeline. The Tribunal said, with reference to arguments put by Mr Ergas (of NECG):

> *... as gas has not previously been available, the ability to monopoly price would be restricted because potential users have bargaining power, the costs of conversion to enable the use of gas are significant, and EGP has committed assets which it has incentives to use. In other words, the prices of existing forms of energy will be a countervailing force on the price of gas and pipeline services...* (Duke EGP decision 2001, paragraph 129).

7.300 In contrast, regional markets along the route of the MSP are established markets that have been served by the pipeline for over 20 years. Hence, the MSP may not necessarily face the same commercial imperatives to develop new markets through efficient tariffs as may be faced by the EGP.

7.301 Ordover and Lehr consider the case for coverage to be especially strong with respect to regional downstream markets:

> *... some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from coverage if it leads to lower transport prices and assured access to the pipeline* (Ordover and Lehr 2001, p.18).

Conclusion: does downstream competition constrain MSP pricing?

7.302 The Council has noted that gas reserves and pipeline capacity do not appear to create impediments to competition in downstream gas sales markets in NSW/ACT. There is evidence of emerging competition between sources of gas supply to Sydney and Canberra markets since the commissioning of the EGP. The introduction of full retail contestability in 2002 offers further scope for competition to be improve over time.

7.303 Nonetheless, the development of downstream competition is an evolving process, with a considerable way to go. There is considerable evidence that downstream markets are not sufficiently competitive to constrain the MSP’s ability to charge monopoly tariffs.

7.304 Upstream and downstream participants have emphasised the complexity of commercial arrangements that impede the ability of gas customers to switch between gas suppliers. In particular, parties have drawn attention to the difficulties of activating price review clauses. Concerns have also been raised that it is sometimes difficult for third parties to gain access to the MSP, despite the existence of spare capacity. To some extent, this may be reflected in the limited number of third party shippers using the pipeline and the modest size of third party shipments.

7.305 Empirical evidence on downstream competition is clouded. There is no empirical data on the cross-price elasticity of demand between the MSP and other pipelines. Apart from one price reduction in July 2000, MSP prices have remained fixed since 1995. The only price adjustment for firm forward haulage on the EGP were tariff increases, effective 1 January 2002. A further rise in EGP tariffs will occur in January 2003, which is likely to further weaken whatever discipline the EGP may previously have applied to the MSP.[108] There

[108] See footnote 80.

has been some innovative marketing by the EGP, but it is too early to judge whether these developments are sustainable.

7.306 While construction of the EGP may have resulted in some loads switching from the Cooper Basin/MSP to Gippsland Basin/EGP, the Council understands that a substantial proportion of EGP volumes are carried for foundation shippers. Evidence was provided to the Council in August 2001 that apart from foundation shipments, about 5 PJ of demand had switched from Cooper Basin to Gippsland Basin gas since 2000 (Gas Advice 2001, sub.5, p.7). This represents about 5% of MSP loads in 2001.[109]

7.307 There has been only limited movement in NSW/ACT markets towards gas customers contracting directly with gas producers and (separately) with gas pipeline owners to ship gas to downstream markets, with only three parties other than AGL currently shipping gas on the MSP. In total, these parties shipped **[confidential information].** (EAPL 2002).

7.308 The introduction of full retail contestability offers greater potential for competition in the gas retail sector. But while 14 retailers are licensed to sell gas in NSW, only one party independent of AGL is currently active in Sydney. There is no active competition in the gas retail sector in Canberra. IPART has cautioned that the emergence of retail competition may be gradual, and the NSW Government considers that incumbent retailers could exercise undue market power for some time.

7.309 The Council has also noted the specific issues for regional markets. Destinations along the route of the MSP Mainline and Canberra Lateral have only one source of gas supply (the Cooper Basin) and the Moomba to Sydney Pipeline System remains a monopoly provider of pipeline services.

7.310 In addition, while laterals other than the Canberra Lateral are not subject to the current revocation application, customers wishing to ship gas from Moomba to points along the laterals would require access to both the lateral in question, as well as the MSP Mainline. For regional markets served by the MSP laterals, the MSP will remain a monopoly provider of pipeline services.

109 Based on published forecast MSP volumes for 2001 of 99.4 PJ (ACCC 2000b, p.91).

7.311 While EAPL has stated a commitment to non-discriminatory pricing, the Council notes that regions along the route of the MSP are established markets that have been served by the pipeline for over 20 years. Hence, the MSP may not face the same commercial imperatives to develop a new market through efficient tariffs as may be faced, for example, by the EGP.

7.312 Ordover and Lehr conclude that there is currently a lack of clear evidence to support a finding of effective downstream competition at present. In particular, there is a lack of empirical evidence on cross-price elasticities and consumer behaviour in response to price changes to reach such a finding:

> *In light of the limited evidence available (*e.g., *a lack of good empirical evidence of the cross-price elasticity of demand for services from different pipelines or evidence that the consumers are actively moving demand among sources of gas supply in response to fluctuations in prices), however, it is premature to conclude whether these structural features are, on balance, consistent with a finding of effective competition* (Ordover and Lehr 2001, p.24).

7.313 Based on its analysis of the structure of the downstream gas sales market, including demand characteristics and observed market behaviour, the Council considers that relevant downstream gas sales markets are not effectively competitive at present, and are unlikely to become so in the short to medium term. While the markets appear to be more competitive than in the past, it is apparent that they are not sufficiently competitive to constrain MSP tariffs.

7.314 The Council's assessment of structural conditions in downstream markets suggests that the MSP is likely to have sufficient market power to charge monopoly tariffs to downstream pipeline users. This may lead to higher delivered prices for gas, and weaker demand for gas. Alternatively, if monopoly pipeline tariffs are absorbed by gas sellers, it would result in lower returns in the downstream market. Either outcome would distort entry incentives in downstream gas sales markets, resulting in a less competitive environment in those markets.

Pricing outcomes and market power

7.315 In paragraphs 7.132 to 7.314 of this report, the Council has examined structural conditions in upstream and downstream markets to assess whether the MSP has the ability and incentive to charge monopoly tariffs.

7.316 Ordover and Lehr propose that an alternative way of assessing whether there is effective competition in dependent markets is to consider pricing *outcomes* as evidence of the exercise of market power. If the MSP is effectively constrained by upstream and downstream competition, monopoly pricing is likely to be unprofitable. But if pricing outcomes reveal evidence of monopoly rents (that is, prices exceed long run economic cost), it can be inferred that market conditions in at least one dependent market are *not* effectively competitive.

7.317 While pricing above long-run economic cost would provide evidence on the state of competition in dependent markets (and hence, the MSP's ability to charge monopoly prices), it would also provide direct evidence that the MSP is, as a matter of fact, exercising market power in at least one dependent market.

7.318 One of the best indicators of whether the MSP is able to exploit market power in dependent markets is:

> *whether current prices are substantially above long-run economic costs, which is the level that they should attain in the presence of effective competition* (Ordover and Lehr 2001, p.19).

7.319 At the time of the Council's Draft Recommendation, the best evidence available on whether the MSP can charge monopoly tariffs was the ACCC's draft determination on the EAPL access arrangement for the Moomba to Sydney Pipeline System under the National Gas Code.

7.320 The ACCC draft determination, adjusted for revisions in the regulatory treatment of deferred tax liabilities, indicates that current MSP tariffs are about 32% higher than tariffs allowable under the National Gas Code.[110]

7.321 Section 8.1 of the National Gas Code requires that reference tariffs under the Code should be designed with a view to achieving the following objectives:

(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of

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110 Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005, adjusted to reflect recent changes in the ACCC's approach to deferred tax liabilities ($0.50/GJ). See Table 4 following paragraph 4.129. See also footnote 41.

delivering the Reference Service over the expected life of the assets used in delivering that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

7.322 The Tribunal found in the *DEI Queensland Pipeline decision* [111] that

> *Sections 3.4 and 3.5 of the Code have been drafted on the basis that an Access Arrangement, as well as the Reference Tariff and Reference Tariff Policy included in that Arrangement, must comply with the Reference Tariff Principles described in s 8 of the Code.*
>
> *.. Section 8.1 of the Code lists a number of objectives.... (F)or example, the objective listed in s 8.1(b) of the Code is "replicating the outcome of a competitive market". The outcomes of a competitive market involve not only prices that reflect efficient costs, but a range of non-price attributes (such as conditions of delivery and innovation) tailored to what customers want.*
>
> *The s 8.1 objectives are those which characterise the outcomes of a market that works optimally. Market performance is a function of price and non-price conduct. Non-price conduct can affect the achievement of the objectives of s 8.1.*
>
> *... The Code requires the ACCC to seek to achieve the objectives set out in s.8.1 not only in setting a Reference Tariff but also in approving any Access Arrangement (DEI Queensland Pipeline decision 2002, paragraphs 46-51).*

7.323 The Council considers that the Tribunal's interpretation of s.8.1(b) of the National Gas Code affirms that this involves prices that reflect

111 *DEI Queensland Pipeline Pty Ltd v Australian Competition & Consumer Commission (2002) ACompT 2.*

efficient costs as well as non-price attributes tailored to what customers want. The ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code.

7.324 Ordover and Lehr note that an appropriate estimate of economic costs is a matter of some contention, but point to the substantial gap between the ACCC tariffs and current pricing:

> *If one assumes that the ACCC's estimates are accurate to within plus or minus 10 percent of the true level of economic costs, then this suggests that competition in the source and destination markets has not been -- and is not currently -- sufficiently potent to keep prices at levels that one would expect in effectively competitive markets.* (Ordover and Lehr 2001, p.19).

7.325 The Council considers that the ACCC tariffs, considered in conjunction with the Tribunal's findings in the *DEI Queensland Pipeline decision*, indicate that absent coverage, the MSP has enough market power to set prices substantially above efficient costs. This also indicates that competition in upstream and downstream markets is not sufficiently effective to constrain monopoly pricing.

Criticisms of this approach

7.326 A number of stakeholders raised concerns that it may be inappropriate to rely on the ACCC's indicative MSP tariffs for the purposes of criterion (a). The principal arguments raised were:

(a) A tariff held durably above a competitive market price may not be evidence of monopoly rents.

(b) The Tribunal has cast doubt on efficient cost as an appropriate benchmark for criterion (a).

(c) The ACCC estimates are regulated prices, rather than competitive market prices.

(d) The ACCC estimates adopt a pricing methodology set out in the National Gas Code, which does not apply efficient costs principles.

Above-competitive pricing may not be monopoly pricing

7.327 In discussions with the Council, EAPL has argued that tariffs held durably above competitive market prices should not be construed as evidence of monopoly rents, unless it can be established that the rents were derived by restricting supply. EAPL argues that there is no evidence of supply being restricted with respect to the MSP.

7.328 According to KPMG, acting for EAPL:

> *.. the paper by Ordover and Lehr seems to be erroneous in assuming that a tariff held durably above a competitive market price is evidence of monopoly rents. Assuming it were established that a tariff is above a competitive market price, this would be evidence of rents but would not support a finding of monopoly rents unless it was also established that the rents were derived from the exercise of monopoly power, that is by restricting supply. There is no evidence of supply being restricted in this case and so there is no basis for a conclusion that there are monopoly rents. The paper's conclusions regarding coverage would only follow if the rents derived from monopoly power. There is no evidence to support the existence of monopoly rents* (KPMG 2002, p.3).

7.329 The Council observes that a restriction in supply is a direct consequence of monopoly pricing. This is because pricing a service above long-run efficient costs will constrain demand below competitive market levels.[112] At the margin, some customers who are willing to pay an efficient price may be unwilling to pay an above-competitive price. In this sense, a producer may restrict supply through the impact of monopoly pricing on demand. This means that evidence of monopoly pricing translates directly into evidence of restricted supply.

7.330 Recent section 46 cases establish that market power exists when a firm can behave persistently in a manner different from the behaviour that a competitive market would enforce on a firm facing otherwise similar cost and demand conditions *(Queensland Wire Industries Pty Ltd* v *The Broken Hill Proprietary Ltd and Another* 167 CLR 177 *(1989)* p.200; *Melway Publishing Pty Limited v Robert Hicks Pty Limited (2001)* 205 CLR 1, 21; 178 ALR 253, 264). An example of such behaviour is the ability to raise prices by restricting output. According to Miller:

> *Market power is, in essence, the power to behave in a market in a manner not constrained by competitors in that market for a sustained period of time. This is often expressed as the ability to raise prices by restricting output, but market power may be manifested by other types of behaviour such as engaging in*

112 Unless demand is perfectly inelastic.

> *predatory pricing persistently or for a sustained period.* (Miller 2002, p.276)

7.331 For example, in *Queensland Wire Industries Pty Ltd v The Broken Hill Pty Ltd 1989* (***Queensland Wire***), the High Court related the exercise of market power to the ability of a firm to raise prices above the supply cost:

> *Market power can be defined as the ability of a firm to raise prices above the supply cost without rivals taking away customers in due time, supply cost being the minimum cost an efficient firm would incur in producing the product... (ATPR 40-925).*

7.332 The Council concludes that evidence of monopoly pricing provides direct evidence of the exercise of market power.[113]

Is efficient cost an appropriate benchmark?

7.333 Some parties have argued that in the *Duke EGP decision*, the Tribunal rejected an approach that infers the exercise of market power from tariffs being set above efficient levels (see, for example, Duke Energy 2002, sub 21, p.4).

7.334 The Tribunal said that:

> *... criterion (a) requires a consideration of whether competition would be promoted – not whether it is efficient....* (Duke EGP decision 2001, paragraph 109)

7.335 The Council considers that the point being made by the Tribunal is that the focus of criterion (a) is not whether or not prices should reflect efficient outcomes, but rather, whether coverage is likely to lead to a more competitive environment than would exist without coverage. Criterion (a), as noted by the Tribunal, requires consideration of the conditions with and without coverage. If the "with coverage" environment suggests that prices are likely to be lower than prices absent coverage, and, there will be a movement of

113 NECG has argued that MSP aggregate revenues would exceed long run costs if the pipeline has the ability to capture a share of Ricardian rents associated with gas supply at Moomba. NECG argues that, in these circumstances, a surplus of aggregate revenues above long run costs would therefore not be an indicator of monopoly pricing. The Council considers this argument at paragraphs 7.389 - 7.393.

those prices towards efficient cost, then it is likely that coverage would create conditions for more competitive outcomes.

7.336 The AGA points out that in competitive markets, prices may deviate from efficient long run costs, and quotes Ordover in this regard:

> *…Even the model of perfect competition allows prices in the short-run to deviate from the long-run equilibrium of minimum long run average cost. In the short-run, when firms possess asymmetric information, heterogeneous vintages of capital, and are offering differentiated services…This leads to a natural dispersion in competitive strategies and observed outcomes in pricing and investment behaviour…The mere fact of these differences is insufficient to demonstrate that the market is not effectively competitive or that a particular firm possesses a substantial degree of market power* (Ordover 2000, p.24).

7.337 The Council notes that in a competitive market, pricing outcomes may deviate from efficient levels in the short term, due to the normal iterations that occur in response to fluctuations in supply and demand conditions. In this sense, it is true that efficient prices may not be a reliable guide to competitive market outcomes in the short term: at times, competitive prices may be above efficient levels; while at other times the reverse may occur. In the longer term, however, prices in a competitive market will tend to track around efficient costs as market disciplines are imposed.

7.338 Competitive prices are difficult to estimate, especially in network industries characterised by significant fixed costs and low variable costs. Ordover and Lehr explain that, for the MSP:

> *... since a substantial share of the costs ... are sunk or fixed, if competition were robust, it is possible that prices might fall below long-run average costs in the short-run. In the long-run, firms must be able to recover their costs to remain viable. Consequently, over a sufficiently long planning horizon, prices must average out at levels that ensure recovery of full costs, including the cost of capital* (Ordover and Lehr 2001, p.19).

7.339 The Council accepts the general principle raised by the AGA that short term price fluctuations around efficient levels are a normal part of the operation of a competitive market. The Council observes, however, that in this instance, MSP tariffs have shifted only once since 1995. In this sense, market volatility appears to have settled, and the market price appears to have reached a stable point. As such, the Council considers that, in the absence of market power, the market price should tend closely towards efficient long run costs.

Regulated prices or efficient prices?

7.340 EAPL argues that the ACCC estimates are not an appropriate benchmark for efficient costs. According to EAPL:

> *It is assumed by the Council, without discussion or analysis, that the ACCC's draft decision under the Gas Code is measuring "long run economic costs", which is not the case. The ACCC's draft decision attempts to determine a regulated price derived by reference to the Gas Code, not the competitive market price for services provided by the MSP* (EAPL 2002, sub.19, p.13).

7.341 In the *Duke EGP decision*, the Tribunal noted that equating regulated outcomes with efficient outcomes fails to take account of the fact that regulation is a second-best option:

> *... regulation is a second best option to competition. The complex nature of the tariff-setting process, the number of assumptions it relies on, and the fact that the reference tariff is a publicly available price which may be varied by negotiation between the pipeline owner and user depending on the user's requirements and conditions in the marketplace, all point to the fact that the reference price is not necessarily the price which would result from competition. Indeed, ACCC in its Draft Decision on MSP tariffs pointed out that if the EGP did not exist the reference tariff for the MSP would be lower as it would be transporting more gas. This is not what one would expect in a competitive market* (Duke EGP decision 2001, paragraph 110).

7.342 NECG makes a similar point:

> *As a threshold matter it is invalid to compare a single price at one point in time with a level of prices which is designed to recover economic costs of pipeline ownership over its entire life. In effect that is what the NCC has done by using the ACCC price to claim that current MSP prices significantly exceed a contestable market price. In fact MSP tariffs are moving. They have moved significantly between the lodgement of the Access Arrangement and the present—as have a range of influential parameters, such as the corporate tax rate* (NECG 2002, sub.19, App. A, p.3).

7.343 The Council notes that criterion (a) requires an assessment of competitive conditions in dependent markets with and without coverage. The Council considers that the best available guide to MSP prices with coverage is provided by the revised draft indicative tariffs proposed by the ACCC (see paragraph 7.315 to 7.356), developed in accordance with the National Gas Code. The Tribunal noted in the *DEI Queensland Pipeline decision* that the objectives listed at s.8.1 of the Code include “replicating the outcome of a competitive market,” and affirmed that this involves prices that reflect efficient costs as well as non-price attributes tailored to what customers want (see paragraph 7.322).

7.344 The Council observes that the ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code. The Council therefore considers that regulated tariffs under the Code are consistent with efficient cost principles.

Are the ACCC estimates a reliable guide to efficient cost?

7.345 The MSP indicative tariffs proposed by the ACCC are based on the pricing principles in the National Gas Code. NECG is critical of these tariffs (NECG 2002, sub.19). Their principal claims are that:

(a) the ACCC did not correctly apply the provisions of the National Gas Code in its tariff calculations; and

(b) even if the ACCC had applied the National Gas Code correctly, the Code does not provide a reliable guide to efficient cost-based pricing. NECG argues that an appropriate pricing benchmark is contestable market pricing, as applied by the hypothetical new entrant test. NECG argues that the Code does not apply this test.

7.346 The hypothetical new entrant test (**HNET**) is an attempt to derive a hypothetical ‘competitive’ market price for an industry that is not competitive. NECG describes the test as follows:

> *This test asks what tariff level (or permitted revenue level) would just be sufficient to encourage an efficient hypothetical new firm to enter the market, assuming it could completely displace the incumbent service provider. This test sits behind the traditional regulatory preference for efficient costs over actual costs of the incumbent, and the use of the DORC asset valuation method.*
>
> *The hypothetical new entrant is assumed to operate efficiently, and to invest optimally. However, this hypothetical new entrant thought experiment must be implemented in a thorough manner if it is to arrive at the contestable market price. A hypothetical new entrant is not likely to inherit the baggage of an incumbent, whether that baggage is unfavourable (such as obsolete equipment, gold plated assets or outmoded work practices) or favourable (such as peculiarities in the tax position of an incumbent or below-budget construction outcomes on some assets). Selectively adopting the best elements from each scenario*

> *(hypothetical versus actual) will not yield the contestable market price. If the hypothetical new entrant test is to be used effectively, it must be used in its entirety* (NECG 2002, sub.19, App. A, p.11).

7.347 NECG argues that a proper application of the hypothetical new entrant test results in a revenue requirement equivalent to that proposed by EAPL in its access arrangement for the MSP. In other words, the gap between the ACCC estimates and the cost estimates proposed by EAPL can be entirely explained by a failure to apply an appropriate methodology for measuring efficient costs.

7.348 As a separate exercise, NECG also compares the methodology applied by the ACCC to the MSP, with the principles outlined in the ACCC's *Draft Statement of Principles for the Regulation of Transmission Revenues* (**DRP**). NECG cites the ACCC as stating that the DRP aims to approximate pricing that would occur in the presence of competitive forces.

7.349 NECG applies the DRP to estimate a revenue requirement for the MSP. NECG argues that the outcomes of this exercise are similar to those proposed by EAPL for the MSP – but are at least 37% higher than the ACCC draft decision revenue requirement for the MSP.

7.350 According to NECG:

> *We have relied only upon a methodology published by the ACCC itself. We have used the values for ORC and WACC which were used by the ACCC itself in its Draft Decision. We have also adopted the O&M cost estimate used by the ACCC in its Draft Decision. The remaining parameters "p" and "L" were estimated on the basis of the best available evidence, and the sensitivity of the result to those estimates was tested.*
>
> *This example calculation must cast profound doubt over the NCC's use of the ACCC Draft Decision as evidence of monopoly pricing by the MSP. A benchmark espoused by the ACCC which, unlike Gas Code benchmarks, is intended to approximate pricing that would occur in the presence of competitive forces, turns out to be within 10% of EAPL's proposed revenue requirement, and between 37% and 60% higher than the ACCC Draft Decision revenue requirement* (NECG 2002, sub.19, App. B, p.5).

7.351 The Council sought advice from the ACCC on the criticisms raised by NECG. The ACCC provided advice to the Council on specific criticisms made by NECG regarding the proper application of the

National Gas Code (ACCC 2002b).[114] In addition, the ACCC engaged National Economic Research Associates (**NERA**) to report on the application of the HNET to MSP pricing. (NERA 2002a)[115]. Below, the Council draws on the ACCC advice and the NERA report to consider the criticisms raised by NECG.

Proper application of the National Gas Code

7.352 NECG highlights a number of areas where it considers that the ACCC applied the National Gas Code incorrectly or inconsistently in its Draft Decision. The key criticisms are that the ACCC incorrectly:

(a) uses a different asset life (50 years) to calculate the depreciated optimised replacement cost (DORC) from that used to calculate forward depreciation (80 years).

(b) uses an asset life of 80 years for the MSP Mainline, which is inconsistent with the pipeline's remaining economic life.

(c) deducts accumulated deferred tax liabilities from the asset base.

(d) removes a contingency factor of $84 million from the value of the optimised replacement costs (ORC).

(e) adopts a weighted average cost of capital that is too low; first, because the ACCC underestimates risk; second, because the ACCC uses an effective tax rate rather than the statutory tax rate.

(f) excludes the cost of working capital from its calculation of the MSP's revenue requirement.

7.353 The ACCC has provided advice to the Council, explaining its approach to each of the above matters. The ACCC maintains that the approach it adopted in most instances is appropriate under the National Gas Code (ACCC 2002b, pp.4-11).[116] However, the ACCC

114 Provided at Attachments 6 and 7 of this report.

115 Provided at Attachment 8 of this report.

116 The ACCC points out that it will further consider the issues raised by NECG in the context of its final decision on EAPL's proposed access arrangement for the MSP (ACCC 2002b, p.12).

notes that regulatory approaches to the treatment of deferred tax has evolved since its 2000 draft decision on the MSP access arrangement, and that it may be appropriate to add back deferred tax liabilities for the purpose of tariff determination. The ACCC estimates that this would add about $0.03/GJ to MSP reference tariffs (ACCC 2002b, p.5).

7.354 This amendment would adjust the ACCC indicative tariffs for MSP services as follows:

(a) the average 2001-2005 Moomba to Sydney tariff would rise from $0.47/GJ to $0.50/GJ.

(b) the average 2001-2005 Moomba to Canberra tariff would rise from $0.43/GJ to $0.46/GJ.[117]

7.355 A comparison of the current Moomba to Sydney tariff ($0.66/GJ) against the adjusted ACCC indicative average tariff ($0.50/GJ) suggests that current MSP tariffs are about 32% higher than tariffs allowable under the National Gas Code.

7.356 The Tribunal noted in the *DEI Queensland Pipeline decision* that the objectives listed at s.8.1 of the Code include "replicating the outcome of a competitive market," and affirmed that this involves prices that reflect efficient costs as well as non-price attributes tailored to what customers want. The Council notes that the ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code (see paragraph 7.321 to 7.323).

Application of the Hypothetical New Entrant Test

7.357 NECG argues that even if the ACCC had applied the National Gas Code correctly, the Code is not an appropriate guide to efficient cost-based pricing. NECG argues that an appropriate pricing benchmark for determining contestable prices and whether a firm is exercising market power is the hypothetical new entrant test (**HNET**). NECG argues that the Code does not apply this test.

7.358 The ACCC notes that while the National Gas Code does not apply the HNET to determine reference tariffs, the test nonetheless has some relevance in tariff setting under the Code. In particular, the test is one mechanism for deriving a competitive (hypothetical)

117 Tariffs exclude GST.

market price for an industry not subject to competition. The outcome of a competitive market is one of the principles that the regulator must take into account in determining reference tariffs under the Code (ACCC 2002b, p.1).[118]

7.359 The ACCC engaged NERA to provide advice on the HNET (NERA 2002a).

7.360 NERA expressed reservations as to whether it was appropriate to apply the HNET to natural monopolies:

> *Whether it is an appropriate regulatory goal to ensure prices are no higher than these hypothetically competitive levels is a separate question. Attempting to set prices of natural monopolies in the same way as prices of competitive industries may or may not be an appropriate objective. The price volatility associated with cost recovery in competitive markets may not be appropriate for markets with very long lived, dedicated and immobile assets. In addition, there may be a significant information burden placed on those carrying out the hypothetical new entrant test. However, such issues are beyond the scope of this report (NERA 2002a, p.7)*

7.361 NERA is also critical of the way NECG applies the HNE test. In particular, it is critical of NECG's use of firm-specific volumes (volumes flowing through the MSP) rather than downstream market volumes (MSP volumes plus EGP volumes).

7.362 In its submission, NECG concluded that the revenue requirement of a hypothetical new entrant is about $89m, in contrast to the ACCC's proposed revenue requirement of $59m in its Draft Decision (NECG 2002, sub.19, App. A, p.15). NECG argues that the current MSP tariff of $0.66/GJ (Moomba to Sydney) is consistent with the HNET revenue stream.

7.363 Underlying NECG's conclusion is the assumption that the HNET tariffs should be based on current volumes for the MSP. The Council notes that MSP volumes are currently at a low point (see Table 7, section 4 of this report).

[118] The ACCC adds, however, that a tariff determined in accordance with the HNET is not necessarily the appropriate reference tariff under the Code. Replication of a competitive market is only one of many factors that the Commission must consider in determining reference tariffs (ACCC 2002b, p.2).

7.364 NERA points out that if the HNET is applied in the way NECG proposes, entry of the EGP would result in tariffs rising (because the required revenue is spread over a reduced volume). This highlights an anomaly in the NECG analysis: entry of the EGP results in the contestable market price increasing. NERA points out that it is counter-intuitive and contrary to economic theory for competition to cause prices to rise.

NERA's approach to the HNET

7.365 NERA argues that a proper application of the HNET would ask the following question:

> *What is the maximum price an incumbent could charge if there was a credible threat of entry? In other words what is the maximum price consumers would be willing to pay an existing infrastructure owner if they had the hypothetical option to overcome transaction costs and negotiate as a coalition with a new entrant to provide substitute services? (NERA 2002a, p.2)*

7.366 NERA argues that the relevant set of consumers are all those customers of delivered gas in the relevant market or markets that the hypothetical new entrant would target. In the context of the MSP, this includes all customers of delivered gas in NSW/ACT (NERA 2002a, p.14). In the market for delivered gas in NSW/ACT, customers are currently served by two major pipelines: the MSP and the EGP. It is likely that customers would regard delivered gas from Gippsland Basin and from the Cooper Basin as near perfect substitutes (NERA 2002a, pp.13-14).

7.367 The hypothetical new entrant test therefore inquires: what is the most efficient pipeline network for delivering gas to final customers in NSW/ACT, starting from a position of no existing pipeline infrastructure, and assuming that all gas consumers can collectively negotiate for gas supply? NERA argues that the least cost method for supplying existing gas transport from the Cooper Basin to customers in the NSW/ACT is likely to use a single pipeline to serve those markets – as this would maximise capture of economies of scale.[119] If so, the new entrant price must reflect the cost of servicing the entire downstream gas sales markets from a single, efficiently built pipeline. This price will depend on total downstream market volumes

119 This is an upper bound since it is possible that a pipeline from an alternative gas basin would lower costs.

– not the volume serviced by any single pipeline. NERA argues that this is appropriate, since the purpose of the new entrant test is to abstract from issues of existing capacity to consider what prices would be with efficient capacity. In other words, the hypothetical new entrant test states that if having two pipelines is less efficient than having one pipeline the total cost of transportation paid by final customers should not increase simply because investment in two pipelines has taken place (NERA 2002a, pp.17-18).

7.368 Hence, the correct methodology for applying the HNET would be to determine the costs of constructing an optimal pipeline to supply downstream markets as a whole, and use total downstream market volumes (not firm-specific volumes) to determine tariffs.[120]

7.369 Applied in this way, NERA argues that the upper bound estimate for the hypothetical new entrant price would be given by dividing:

(a) the annual cost of a new pipeline from Moomba to Sydney given today's cost parameters; by

(b) current ACT/NSW gas transportation quantities.

7.370 The Council notes that the NERA methodology removes the conceptual anomaly in the NECG analysis that competition causes prices to rise.

7.371 NERA calculates that the hypothetical new entrant price to ship gas from Moomba to Sydney is about \$0.51/GJ. That is, \$0.51/GJ is the

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120 NERA points out that this methodology is not inconsistent with the concept of a point to point service, as articulated by the Tribunal in the *Duke EGP decision*, and adopted by the Council. NERA states that:

There is no inconsistency with the adoption of a 'point to point' service definition 19 for existing pipelines and the fact that the hypothetical new entrant test allows for the possibility of re-optimisation of existing pipeline systems such that all existing 'points' need not be served by the hypothetical new entrant. It is clear that an existing gas pipeline carries gas from one point to another point (or set of points). It is therefore sensible when considering the market power of an existing pipeline to recognise that it may have market power at any of these 'points' – eg, in the market for delivery of gas from point A and in the market for delivery of gas to point B (or at any intermediate points).

The hypothetical new entrant test simply allows for the (theoretical) possibility that the manner in which all 'points' are currently served is not the most efficient/least cost. It does not mean that one can ignore the manner in which 'points' are actually connected when performing actual (as opposed to hypothetical) market analysis. (NERA 2002a, p.16).

maximum price that would be expected in a competitive market. The current tariff charged by EAPL ($0.66/GJ for Moomba to Sydney) is about 30% higher than the HNET tariff.[121]

7.372 NERA concludes that:

> *The foregoing analysis and the results... suggest that in each of the last two years the MSP has been charging tariffs around 30 percent above an upper bound estimate of the hypothetical new entrant tariffs. This is evidence of the exercise of market power by the MSP* (NERA 2002a, p.37). *The reason MSP prices exceed new entrant prices by more than revenues is that the entry of the EGP in financial year 2001 has resulted in a loss of market share to the MSP and reduced MSP revenues towards new entrant levels but not prices received by consumers (NERA 2002a, p.37).*

7.373 To test the implications of using different volume assumptions, NERA applies the hypothetical new entrant test to the MSP *prior* to the entry of the EGP. This effectively excludes the impact of different volume assumptions between the NERA and NECG models – because prior to the entry of the EGP, market volumes and MSP volumes were virtually identical.

7.374 NERA calculates a hypothetical new entrant price of around $0.50/GJ prior to the entry of the EGP (NERA 2002a, p.37). This compares with an actual MSP tariff prior to EGP entry of about $0.71/GJ for the Moomba–Wilton service. Thus, MSP tariffs were about 42 percent above the hypothetical new entrant price.

7.375 Since then MSP prices have fallen by around 7 percent to $0.66/GJ (on the Moomba – Wilton service) but remain over 30 percent above the hypothetical new entrant price of $0.50/GJ. This suggests that either:

(a) entry of the EGP somehow caused competitive prices to rise by around one third (from $0.50/GJ to $0.66/GJ); or

(b) MSP prices remain substantially above competitive levels (ie, the MSP is exercising market power).

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121 The ACCC points out that the HNET tariff of $0.51 is based on the operating costs originally proposed by EAPL in 1999 (around $12m per annum). In its revised access arrangement EAPL has proposed operating costs of around $23m per annum. The ACCC has requested EAPL to provide evidence to support the higher level of costs. The ACCC states that even if the HNET tariff is based on the higher level of operating costs, NERA's conclusion that EAPL is exercising market power would still stand (ACCC 2002b, p.12).

7.376 NERA argues that there is no convincing explanation as to why the entry of a new firm would cause competitive benchmarks to rise. As such, the second alternative is more credible. NERA concludes that MSP prices remain substantially above competitive levels and that this reinforces their finding that the MSP is currently exercising market power.[122]

Further debate on HNE prices

7.377 The Council released the NERA report and ACCC advice to interested parties for comment in September 2002. The Council received submissions on these documents from EAPL/NECG and AGL.

7.378 The NECG submission (NECG 2002, sub.27) raised a number of criticisms of the NERA approach to HNE pricing. The principal criticisms are:

(a) the NERA approach to depreciation charges is excessively conservative and does not take account of the risk of asset stranding.

(b) the NERA analysis considers market power from the ability to monopoly price rather than the ability to earn monopoly returns. NECG argues that this approach lacks sound

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[122] NERA proposes that an alternative benchmark to the HNET for assessing MSP tariffs is an approach based on the notion of a regulatory contract (NERA 2002a, pp.4, 38-41). This approach considers the ability of a firm to recover reasonable costs over the life of an asset. NERA argues that "it appears reasonable to believe that the regulatory frameworks governing the past pricing of the MSP have had significant regard to providing owners of the MSP with certainty over the recovery of the sunk costs in exchange for a commitment that customers would not pay significantly more than the actual costs of the pipeline over its life." NERA argues that if it is accepted that a regulatory contract exists for the MSP, then the National Gas Code would be the best guide to appropriate prices. In this context, appropriate MSP tariffs would be those determined by the ACCC under the regulatory processes of the Code.

The Council notes that some aspects of the National Gas Code are similar to the regime set out in the *Moomba-Sydney Pipeline System Sale Act 1994*. For example, s.80(7) requires that the arbitrator of a dispute (over pricing or other matters) take account of a list of specified factors. The list is similar (but not identical) to the factors that must be considered by the regulator and arbitrator under the National Gas Code. The Council considers that the argument that a regulatory contract exists may have some merit. However the Council has not formed a definitive view on this matter for the purposes of the MSP applications.

economic underpinnings, and is a departure from the approach used by the ACCC in other contexts.

(c) NERA's "one pipeline" approach ignores the economic benefits of diversity of supply. It is also inconsistent with ACCC and NERA positions in other contexts. The approach could result in asset stranding, and create disincentives for efficient new entry.

(d) even if the MSP's aggregate revenue did exceed long run costs, this may not indicate monopoly pricing. Rather, it may reflect that EAPL is obtaining a share of Ricardian rents associated with gas supply at Moomba.

7.379 The Council sought further comment from NERA on these criticisms. NERA's report (NERA 2002b) is provided in full at Attachment 9 of this report.

7.380 The Council notes that many of NECG's criticisms (for example, the treatment of depreciation and the approach to determining efficient volumes) relate to discrepancies between NERA's application of the hypothetical new entrant test (HNET) and actual regulatory practice. This confuses the purpose of the HNET: it is a device (proposed by NECG) for estimating contestable market prices for the purposes of coverage decisions on natural monopoly infrastructure. It is not widely used in regulatory decision making, and nor is it claimed to be (NERA 2002b, p.4).

7.381 For example, the ACCC draft decision on the MSP access arrangement (ACCC 2000b) proposed to regulate MSP tariffs on the basis of MSP-specific volumes. Thus, regulatory practice under the National Gas Code would compensate the MSP's owners for any loss of volumes since the entry of the EGP.

7.382 NERA argues that it has addressed the issue of asset stranding by assuming the MSP is the most efficient pipeline for the delivery of gas to NSW/ACT. Therefore it has treated the MSP's capital base as efficient – that is, there has been no "write down" for the purposes of setting the optimised value.

7.383 While there may nonetheless be a risk of inefficient entry, this could only occur if investors in bypass infrastructure perceive that monopoly pricing by the incumbent would make inefficient bypass profitable. In other words, compensating for the risk of inefficient bypass appears to amount to an assumption that the MSP is engaging in monopoly pricing.

7.384 The Council notes NECG's claim that market power does not relate to the ability to monopoly price. Nonetheless, NECG states elsewhere in its submission that:

> *Rents from market power involve price-setting behaviour* ...(NECG 2002, sub.27, p.14)

7.385 There are several ways to determine and describe the exercise of monopoly power. While the ability to price above cost is not necessary for such a finding, it is clear that the ability to monopoly price will be evidence of the exercise of monopoly power. In the Queensland Wire decision, Mason CJ and Wilson J found that:

> *Market power can be defined as the ability of a firm to raise prices above the supply cost without rivals taking away customers in due time, supply cost being the minimum cost an efficient firm would incur in producing the product* ...(Queensland Wire decision 1989 167 CLR at 189).

7.386 The Council has noted the claim that NERA's "one pipeline" approach ignores the economic benefits of diversity of supply. In particular, NECG argues that diversity of supply (and multiple pipelines) may reduce delivered gas prices by raising aggregate supply and by creating scope for competition between gas basins. Diversity also improves security of supply.

7.387 The benefits of interbasin competition would need to be substantial to offset the impact of multiple pipelines on transport costs. It is more likely that consumers would negotiate directly with gas fields, using the threat of bypass, to deliver the benefits of interbasin competition (NERA 2002b, p.11).

7.388 The Council also notes that the security of supply benefits of multiple pipelines are likely to be already addressed by the Interconnect.

7.389 Finally, the Council notes the argument that even if the MSP's aggregate revenue did exceed long run costs, this may not indicate monopoly pricing. Rather, it may reflect that EAPL is obtaining a share of Ricardian rents associated with gas supply at Moomba

7.390 NECG define the difference between monopoly rents and Ricardian rents as follows:

> *Rents from market power involve price-setting behaviour; Ricardian rents accrue to inframarginal low-cost sources of supply independently of any power over price.* (NECG 2002, sub.27, p.14)

7.391 The Council observes that Ricardian rents are generally viewed as premiums attaching to a highly productive and/or conveniently located natural resource. Importantly, Ricardian rents attach to the factor that drives cost savings and/or the higher value to consumers, such as the productive land. This is important from an efficiency perspective, because it ensures that such advantages are fully exploited. The earning of Ricardian rents are associated with lower supply costs into competitive markets, and therefore do not affect prices or volumes.

7.392 In this sense, it is generally not appropriate that Ricardian rents be captured by natural monopoly infrastructure. Indeed, if the MSP is capable of expropriating upstream rents, it would suggest that the MSP is able to exercise market power in the upstream market. If the MSP gathers those rents by pricing above cost, then those rents accrue from price-setting behaviour rather than from "inframarginal low cost sources of supply." As such, NECG's own definition suggests that any rents to the MSP are due to exercise of monopoly power (NERA 2002b, p.10).

7.393 The Council notes that the MSP's ability to expropriate upstream rents would reduce upstream returns. Lower returns in Cooper Basin gas production would weaken incentives for upstream investment. The Council considers that this is likely to inhibit the competitive environment in the upstream gas sales market (see paragraphs 7.453 to 7.494).

Concluding comments on HNE pricing

7.394 The debate on HNE pricing is evidence of the complexity of deriving contestable market prices for natural monopoly infrastructure. The NECG and NERA approaches result in different HNE prices due to differences in underlying assumptions.

7.395 The gap between the NECG and NERA applications of the HNET is principally accounted for by the difference in underlying volume assumptions. The NECG estimates are based on MSP-specific volumes, while the NERA estimates are based on downstream market volumes.

7.396 The Council notes that an implication of the NECG approach is that entry of the EGP results in an increase in contestable market prices: that is, an increase in competition increases competitive benchmark prices. The NERA approach removes this paradox. For this reason, the Council is inclined to view the NERA approach as the more plausible of the proposed alternatives to HNE pricing.

Other approaches to pricing

7.397 Modelling of MSP costs with regard to the investment actually made by the infrastructure owner – and allowing appropriate returns on that actual investment – provides an alternative to deriving costs from estimates of efficient replacement costs. The Council notes that the recent Supreme Court (WA) *Epic Energy decision*[123] highlighted the relevance of the infrastructure owner's investment in the determination of access prices.

7.398 In its draft decision, the ACCC estimated that valuing the MSP on the basis of EAPL's investment (the 1994 purchase price, adjusted for subsequent investment) generates an initial capital base (**ICB**) ranging from $459m (applying depreciation applied to date by EAPL to derive a book value) to $567.6m[124] (applying depreciation based on an 80 year asset life). These estimates appear broadly in line with an ICB derived from the DORC methodology of $539.5m, as proposed in the ACCC draft decision (ACCC 2000b, p.40-41).

7.399 The ACCC has provided estimates to the Council that current MSP tariffs are about 28 to 50% higher than tariffs derived from an ICB based on the 1994 purchase price. These estimates are based on the $459m to $567.6m range noted above.

Implications of pricing outcomes for criterion (a)

7.400 The Council accepts that there are a number of alternative methods for deriving efficient pipeline tariffs, and that "competitive" prices are notoriously difficult to estimate in network industries characterised by significant fixed costs and low variable costs.

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123 *Re Ken Michael AM: Ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 (23 August 2002).*

124 Inflation indexed since 1994.

7.401 The Council notes that:

(a) The ACCC draft decision on the MSP access arrangement indicates that current MSP tariffs are about 32% above the tariffs allowable under the National Gas Code.[125] The Tribunal noted in the *DEI Queensland Pipeline decision* that the objectives listed at s.8.1 of the Code include "replicating the outcome of a competitive market," and affirmed that this involves prices that reflect efficient costs as well as non-price attributes tailored to what customers want. The Council notes that the ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code.

(b) Modelling of MSP costs with regard to the investment actually made by the infrastructure owner (the 1994 purchase price, adjusted for subsequent investment) would result in current MSP tariffs being about 28 to 50% higher than tariffs derived from an ICB based on the 1994 purchase price.[126]

(c) An estimate by NERA of MSP tariffs that would apply under hypothetical new entrant pricing, found that current MSP tariffs are about 29% above contestable market prices.[127]

7.402 The Council notes that current MSP prices exceed cost based prices and contestable market pricing by significantly more than what would ordinarily be considered as an error margin.

7.403 The Council considers that the combined evidence on cost estimates indicates that current MSP tariffs (that is, tariffs absent coverage) are likely to be significantly above long-run economic cost – the level they should attain in the presence of effective competition. This reinforces the likelihood that the MSP is able to exploit market

[125] Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005, adjusted to reflect recent changes in the ACCC's approach to deferred tax liabilities ($0.50/GJ).

[126] Based on valuation estimates in the ACCC draft decision on the MSP access arrangement: ACCC 2000b, p.41. The range reflects alternative assumptions about depreciation .

[127] Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against NERA estimate of hypothetical new entrant pricing of $0.51/GJ.

power in dependent markets. It also provides evidence that the MSP may be currently exercising that power through monopoly pricing.

7.404 The Council notes that the EGP Longford to Sydney tariff rose by about 6% on 1 January 2002, raising the price of delivered Gippsland Basin gas relative to delivered Cooper Basin gas. Absent coverage, this may allow scope for the MSP to increase tariffs by an equivalent margin to the EGP without risking a loss of sales. This would cause an even wider gap between MSP tariffs absent coverage and the prices likely to apply in the presence of effective competition, as noted above.

7.405 Over time, this gap may widen further, given that EGP tariffs will escalate once again on 1 January 2003, with ongoing annual escalations, in accordance with a formula based on movements in the Consumer Price Index (Duke Energy 2001b).[128]

Would coverage promote competition?

Downstream competition

7.406 In downstream markets, the MSP's ability to monopoly price turns on whether customers are able to switch to alternative sources of gas supply at a competitive price, in the event of monopoly pricing on the MSP. The Council has reported signs of emerging competition in downstream gas sales markets in Sydney and Canberra since the opening of the EGP and Interconnect. However, there is no evidence that downstream markets are effectively competitive at present. All parties, including Duke and EAPL, have agreed that downstream competition is an evolving process. This view is supported by evidence that current MSP tariffs are substantially above long-run economic costs (see paragraphs 7.315 to 7.405).

7.407 Collectively, this evidence suggests that downstream gas sales markets are not sufficiently competitive to constrain MSP pricing. The MSP is therefore likely to have sufficient market power to charge monopoly tariffs to downstream pipeline users.

7.408 If monopoly tariffs are passed on to customers as higher delivered gas prices, the demand for gas is likely to fall. This would weaken entry incentives in downstream gas sales markets, resulting in a less competitive environment in those markets.

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128 See footnote 80.

7.409 Alternatively, if downstream gas sellers absorb a share of monopoly tariffs, the impact on delivered gas prices would be constrained. However, lower returns would reduce incentives to invest in downstream markets, with adverse consequences for the competitive environment.

7.410 An effect of coverage would be to remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide downstream gas sellers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The ACCC draft indicative tariffs (adjusted) indicate that this price is likely to be significantly lower than prices absent coverage.

7.411 If lower transport tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand create incentives for new entrants to invest in downstream gas sales markets to satisfy that demand, thus promoting a more competitive environment in those markets. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).

7.412 Alternatively, if downstream gas sellers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns in gas sales markets will encourage new entry. The threat or event of new entry, in turn, would promote rivalrous behaviour in those markets. Indeed, the mere reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a). Over time, rivalrous behaviour between new entrants and incumbents is likely to compete away downstream rents, such that delivered gas prices will fall.

7.413 The Council concludes that coverage is likely to promote downstream competition regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by downstream gas sellers.

Materiality issues

7.414 NECG argues that, even if coverage results in a significant fall in gas transmission charges, this would not have a material impact on downstream competition (NECG 2002, sub.19, App.E, F). NECG presents its arguments in terms of the likely effects of coverage on:

(a) downstream gas sales;

(b) retailer margins; and

(c) fringe firms.

Effects of coverage on downstream gas sales

7.415 NECG argues that coverage would not have a material impact on downstream gas sales because:

(a) gas transmission charges represent a relatively small proportion of delivered gas prices; and

(b) demand for gas is not very responsive to price changes (that is, the elasticity of demand for gas is low).

7.416 NECG argues that, due to these factors, even a substantial price shift would have only a minor effect on delivered gas prices, and any stimulus to demand would be minor.

7.417 In particular, NECG claims that even if coverage resulted in MSP tariffs being reduced to those proposed by the ACCC (which, according to NECG, constitutes the maximum possible price impact of coverage), this would cause only a 4% reduction in gas retailer costs. NECG estimates that even if this 4% reduction was fully passed on to consumers, final demand would rise by only 2%. NECG concludes that any promotion of competition would therefore be trivial:

> *Therefore, concern about any pipeline monopoly pricing harming competition among gas retailers appears completely overstated. In fact the removal of even the worst-case estimate of monopoly rent would have virtually no quantitative effect whatsoever on the viability of gas retail businesses, nor would it improve the economics of gas retailing to the extent that further entry or investment in retailing would be at all likely to occur as a result of this tariff change.* (NECG 2002, sub.19, App. F, p.1)

7.418 The Council considers that a number of aspects of the NECG analysis may understate the impact of coverage on prices and demand:

(a) the analysis may understate the elasticity of demand for gas;

(b) the stated price impact of "4%" is understated for the contract market; and

(c) the analysis understates the significance of transmission charges.

Elasticity of demand for gas: how reliable is the data?

7.419 The NECG analysis relies on demand elasticity estimates published by AGA/ABARE (AGA 1996). The estimates cover the period 1973-74 to 1993-94 (see paragraphs 4.146 to 4.151). The Council observes that market characteristics may since have changed. The AGA/ABARE report cautioned that, over time, gas demand may become more price responsive than indicated by the estimates, due to factors such as technological change (AGA 1996, p.28).

7.420 In particular, the AGA/ABARE estimates expressly exclude consideration of gas used for "conversion" (AGA 1996, pp.13, 29). ABARE has informed the Council that "conversion" covers such activities as the use of gas for electricity generation.

7.421 In discussions with the Council, NECG agreed that the elasticity of demand for gas sold into intermediate markets (such as for electricity generation) may be higher than the AGA/ABARE estimates (NECG offices, 14 May 2002). It was also agreed that a small price change in gas could make a proposed generator vulnerable to displacement. In such circumstances, demand for gas could be highly responsive to price movements. Thus, a 4% price shift could have a substantial impact on demand.

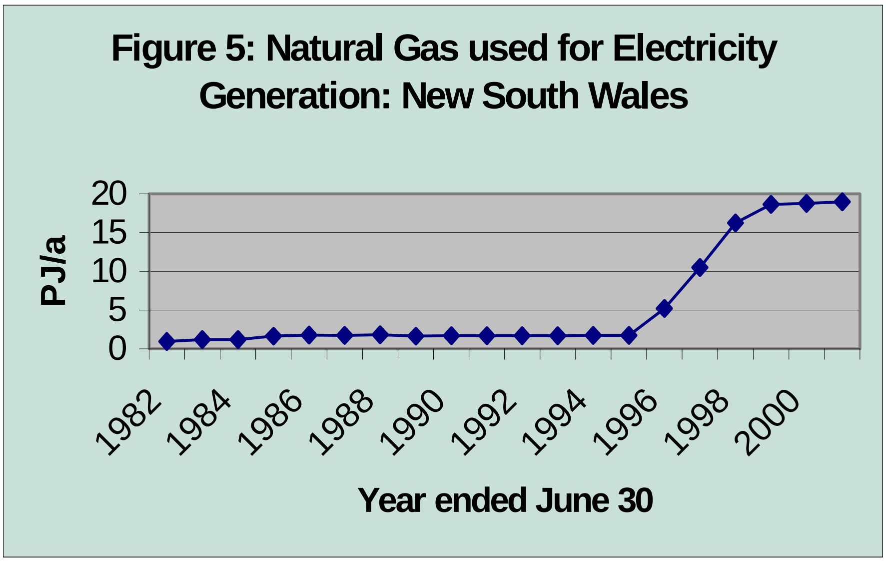
7.422 This view is supported by BHP Billiton, which argues that even a relatively small reduction in delivered gas prices would have a significant effect on margins and market outcomes in gas fired electricity generation.

> *A closer examination of the NECG analysis reveals a totally different picture about the potential effects on downstream industries. For example, the difference between the EAPL access arrangement application ($52.97 million p.a. for the contract market – NECG data) and the ACCC's draft decision on EAPL ($32.08 million p.a.) equates to $0.28/GJ. For a combined cycle gas fired power generator, this is a difference of $2.25/MWh of output. With estimated new entrant pricing of $35.40/MWh, this*

is a significant difference. Thus, monopoly rents in gas have a flow-on effect into electricity (and downstream industries using electricity as an energy source).... (BHP Billiton 2002, sub.24).

7.423 This information suggests that the price elasticity of demand for gas for electricity generation and cogeneration may be considerably higher than is implied by the NECG data.

7.424 The significance of this point is magnified by the fact that electricity generation occupies a much greater share of NSW gas demand than at the time of the AGA/ABARE study. During the data period for that study (1973-74 to 1993-94), the use of natural gas in electricity generation was less than 2 PJ/a. However, NSW demand for gas for electricity generation has since expanded considerably, rising to an estimated 19 PJ/a in 2001 (see Figure 5). This represents about 17% of total NSW demand for gas.[129] The Council concludes that given the sharp rise in gas demand for electricity generation and cogeneration, the sensitivity of gas demand to price changes is likely to have risen since the ABA/ABARE data period, and will continue to rise.



Source: ABARE data provided to the Council by the NSW Ministry of Energy and Utilities. 1999 to 2001 are estimates.

7.425 While some planned new developments in NSW gas-fired power generation and cogeneration have been scaled down or delayed,

[129] Sources: NSW demand for natural gas for electricity generation: unpublished ABARE data provided to the Council by the NSW Ministry of Energy and Utilities in July 2002; NSW demand for gas: 109.4 PJ; reported in ACCC 2000b, p.91.

further growth in demand for gas for these purposes is forecast from around 2005 (ACCC 2000, pp.99-100). EAPL has stated that future growth in demand for gas in NSW is "largely a function of the installation of major gas-fired power generation and cogeneration capacity" (ACCC 2000b, p.93).

7.426 The Council has also been informed that gas demand is very price sensitive in the fertiliser industry. Incitec, a major manufacturer and distributor of nitrogenous products (annual revenues over $120 million) is one of the largest gas users in NSW, consuming some 10.5 PJ/a (around 9% of total NSW gas demand in 2001). Gas is used as a feedstock and for raising process steam for ammonia manufacture, as the first step in the manufacture of nitrogenous fertilizers for the rural sector; and for the production of ammonium nitrate to produce explosives for the mining sector. According to Incitec, both markets are growing strongly, but are heavily import sensitive.

7.427 Gas represents 45% of Incitec's total manufacturing cost and 80% of variable cost for the company's Newcastle plant. Further, Incitec informs the Council that transmission pipeline charges represent about 15% of delivered gas costs.

7.428 Incitec states that:

> *It is critical that gas be delivered to this plant on terms which allow Incitec to match import competition on a delivered Australia basis* (Incitec 2001, sub.10, p.5).

7.429 The Council notes that given the nature of import competition, and the magnitude of gas costs for the company, Incitec's operations are very sensitive to movements in the price of gas. According to information provided by Incitec, a price movement of the magnitude proposed by the ACCC regulatory process would have a material impact on costs.

> *For a fertilizer producer (using gas as a feed-stock, as well as an energy source), this difference equates to $5.50 in a product that wholesales around $280/te* (BHP Billiton 2002, sub. 24)[130]

7.430 This information from major gas users in the electricity generation and fertiliser industries suggests that removing monopoly rents in gas transmission (as identified by the ACCC) would result in a material increase in demand for delivered gas by major consumers –

130 Sub. 24 is a BHP Billiton submission that included information provided by Incitec.

and hence, for commodity gas, gas haulage and gas retail services. In particular, a price change of this magnitude could impact on whether a major customer enters or exits the market. This would stimulate competition between gas producers to supply the load, and hence, would enhance entry incentives in upstream and downstream markets.[131]

Price impact understated for contract market

7.431 NECG estimated that coverage would result in a maximum 4% change in delivered gas prices (NECG 2002, sub.19, App. F, p.3). This estimate is an average for the contract and tariff market.

7.432 However, it is in the contract market that the potential for promotion of competition is more likely[132]. The projected price change in the contract market, according to NECG estimates, is up to 5.4%. The price sensitivity of some large gas users (such as gas-fired electricity generators) is likely to be significantly higher (see paragraphs 7.419 to 7.430).

Relative importance of transmission costs understated

7.433 The NECG calculations are expressly based on 1998-1999 data, and include an estimate for distribution costs in the contract market of $105 million.

7.434 The Council notes that distribution charges in the contract market have fallen considerably since 1998-1999. The IPART revenue path for AGLGN distribution charges in the contract market falls from $105 million in 1998-1999 to about $45 million in 1999-2000, and is expected to remain around that level until at least 2003-2004 (IPART 2000, p.26).[133] If current distribution charges are used, transmission costs account for a relatively higher share of delivered gas prices

131 A significant rise in demand for gas may also stimulate new entry in upstream production markets in the Cooper Basin and Bass Strait.

132 75% of NSW gas is consumed in the contract market (IPART 2001a, p.3). Contract customers consume more than 10 TJ of gas per annum. As such, their decisions have more potential to impact on market conditions than decisions of smaller (“tariff”) customers.

133 Distribution revenues have fallen because of regulatory decisions by IPART. The lower revenues are not related to the introduction of the EGP or other market conditions.

than NECG claims. In the contract market, the price impact of applying the ACCC tariffs rises to about 6.4% of delivered gas prices.

7.435 The Council concludes that a number of aspects of the NECG analysis are likely to understate the effects of coverage on delivered gas prices. In particular, the effect of removing transmission rents identified by the ACCC (as would occur if the MSP remained covered) would reduce delivered gas prices in the contract market by around 6.4% rather than 4%. The Council regards this price impact as non-trivial. Further, gas demand is likely to be more responsive to a price change of this magnitude – especially among major users such as electricity generators and industrial producers – than the NECG estimates suggest.

Effects of coverage on retailer margins

7.436 NECG considers an alternative scenario (to higher delivered gas prices) that could result from revocation of coverage. If revocation led to higher transmission charges, downstream retailers could absorb these costs (rather than passing higher costs on to customers), to cushion the impact on demand. NECG notes that, in theory, this could result in firms exiting the market, making the downstream market less competitive.

7.437 NECG argues that this scenario is unlikely because downstream retailers tend to have low sunk costs and low entry costs, making the market highly contestable. As the elasticity of supply is likely to be higher than elasticity of demand, gas sellers should be able to pass on any price increases to customers.

7.438 If one accepts NECG's analysis (and its underlying assumptions), the implication is that higher transmission costs would be passed on to customers. The analysis therefore reverts to the proposition that the resulting price shift will have only a minor effect on delivered gas prices and demand. As the Council has explained, this analysis appears to understate the price effect of coverage, as well as the relevant demand elasticities.

7.439 NECG argues that if the downstream market is not highly contestable (for example, if the market is an oligopoly), suppliers would be in an even better position to pass on cost rises to customers. As a result, it is unlikely that retailers would need to leave the market (sub.19, App. E, p.7-8). The Council observes that, to the extent that there are barriers to entry in gas retailing, the reduction in gas transmission prices flowing from coverage may be partly captured – at least in the short run – by retailers. The Council notes elsewhere in this report that barriers to entry in gas retailing have been reduced through regulatory reform. Thus, the prospect of increased returns in gas retailing is likely to stimulate new entry over time. This is a pro-competitive outcome flowing from coverage.

Effects of coverage on fringe firms

7.440 NECG argues that, even if monopoly pricing did result in some firms exiting downstream gas markets, this would not necessarily be detrimental to competition:

> *First, any instance of exit by a fringe firm that is not an important source of competitive constraint in a market would, by definition, not result in a reduction of competition in that market. Second, competition in a market is not measured by the number of firms in that market, but by the behaviour of firms in that market. For example, mergers and acquisitions occur in many markets, thereby reducing, in many instances, the number of competitors in a market. However, competition regulators often do not object because competition is not harmed merely because the number of competitors is reduced* (NECG 2002, sub,19, App. E. p.5).

7.441 The Council acknowledges that exit by a firm that is not an important source of competitive constraint in a market would not, by definition, weaken the competitive environment. The Council considers, however, that NECG's views appear to be at odds with the Tribunal's approach to "toe-in-the-water" entry by fringe firms. In particular, low-cost small-scale entry by fringe operators can be an important source of dynamic competition.

7.442 In the *Sydney Airport decision*, the Tribunal referred to "competitive entry by lower cost operators offering a markedly novel or different mix of service and price" (*Sydney Airports decision 2000*, paragraph 124). The Tribunal went on to say that:

> *from an economic perspective new entrants can be a source of innovation and therefore competitive pressure. This is not a matter of the number of entrants but the variety of the competitive behaviour that wider entry would generate. The importance of this factor will, of course, vary between industry sectors depending on a range of factors, such as entry costs and the maturity of the sector. From the evidence available to the Tribunal, however, it would seem that the airline industry is currently undergoing significant structural change, with very*

> *heavy economic regulation giving way to a more light handed and market driven approach*. (Sydney Airports decision 2000, paragraph 125)

7.443 The Council observes that the type of conditions referred to by the Tribunal – significant structural change, with very heavy economic regulation giving way to a more light handed and market driven approach – bears strong similarities with trends in downstream gas sales markets, including the gas retailing sector.

7.444 The Tribunal again emphasised the significance of entry by niche operators elsewhere in its decision:

> *Notwithstanding the difficulties that may be involved in a new entrant building up a sufficient critical mass of business to enable its business to be viable, the Tribunal does not consider that such a barrier to entry will inevitably have the result that either there will be no new entrants into the market or that any new entrant will not be able to survive in the long-term due to an inability to build up a sufficient critical mass of business. It is apparent that international air operators have been dissatisfied with the level of service and competition in the past and that there are a range of airline needs which may be satisfied by what have been called the "niche operators"* (Sydney Airports decision 2000, paragraph 185)

7.445 The Council rejects the notion that the loss of "fringe firms" from downstream markets would not affect competition. The Council agrees with the Tribunal's findings that small players can bring important dynamic benefits to the competitive environment. Thus, if monopoly pricing on the MSP deters "toe-in-the water" entry, it forecloses on a type of entry that is likely to be pro-competitive. Coverage would address this issue by constraining MSP tariffs to efficient levels for all incumbents and prospective new entrants.

Logical extension of NECG arguments

7.446 In the preceding analysis, the Council has found that NECG is likely to understate the effects of coverage on downstream markets. In addition, the Council observes that a logical extension of the NECG analysis is at odds with policy decisions by Australian Governments.

7.447 NECG's conclusions derive from the premise that transmission charges on the MSP account for a relatively small proportion of delivered gas prices, and that gas demand is inelastic. The Council notes that for all Australian pipelines, the transmission price represents a significantly smaller share of delivered gas prices than the well-head gas price (see Table 6, following paragraph 4.136 of this report). This suggests that a logical extension of NECG's argument is that coverage of most – if not all – of Australia's transmission pipelines should be revoked under the National Gas Code.[134]

7.448 This conclusion is at odds with policy initiatives by Australian Governments to implement a National Gas Code to regulate gas transmission pipelines. The Commonwealth, State and Territory Governments gave careful consideration to the list of pipelines to be covered from the outset by the Code (see Schedule A of the Code). In 1997, Governments agreed that coverage of most Australian transmission pipelines was necessary to promote competition in dependent markets. While coverage of a number of transmission pipelines has since been revoked, most of Australia's major transmission pipelines remain regulated, as envisioned by Governments in 1997. The Council would consider it remarkable if the fundamental rationale for access regulation of transmission pipelines had become redundant in the space of five years.

Promotion of downstream competition: concluding comments

7.449 The Council considers that coverage would remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide downstream gas sellers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The ACCC draft indicative tariffs (adjusted) indicate that this price would be significantly lower than prices absent coverage.[135] The Council considers that competition would be promoted regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by downstream retailers.

7.450 The Council has examined NECG's argument that any promotion of competition would be negligible because of inelastic demand and the

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[134] In each case, the extent to which this follows depends on the magnitude of the well-head gas price in relation to the transmission price.

[135] The price differential may be greater than the gap between current MSP tariffs and the adjusted draft indicative tariffs proposed by the ACCC. There is potential scope for MSP tariffs absent coverage to rise above current levels, due to a recent rise in EGP tariffs. EGP tariffs will rise again in January 2003. See footnote 80.

small proportion of delivered gas prices accounted for by transmission tariffs.

7.451 The Council is not convinced by these arguments. In particular, the Council considers that the elasticity estimates cited by NECG may understate current market conditions. In particular, the Council has noted that the demand for gas in the electricity generation sector is likely to be less inelastic than the NECG analysis assumes. Second, the Council has found that the NECG analysis may understate the proportion of delivered gas prices accounted for by transmission tariffs.

7.452 The Council therefore remains satisfied that coverage of the MSP would promote competition in downstream gas sales markets.

Upstream competition

7.453 In the upstream market, the MSP's ability to exert market power turns on whether the Cooper Basin producers have viable options to divert gas sales into other markets in the event of anti-competitive MSP pricing. The only viable alternative at present – the Moomba to Adelaide pipeline – is capacity constrained. While this may change from about 2004, it appears that South Australia's gas demand is not growing fast enough to absorb the sales diversions needed to constrain MSP pricing. Nor is there likely to be scope to divert gas sales into Queensland markets in the foreseeable future. Absent coverage, the MSP is therefore likely to have the ability and incentive to charge monopoly tariffs for shipping Cooper Basin gas. This view is supported by evidence that current MSP tariffs are substantially above long-run economic costs (see paragraphs 7.315 to 7.405).

7.454 Monopoly pricing for MSP services is likely to result in higher delivered prices for gas (which would weaken demand for gas) and/or lower returns in gas production. These conditions are likely to reduce gas production and distort entry incentives in the upstream market, weakening the competitive environment in that market

7.455 An effect of coverage would be to remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide upstream producers and gas buyers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The ACCC draft indicative tariffs (adjusted) indicate that this price would be significantly lower than prices absent coverage.

7.456 If lower tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand would stimulate higher rates of production, creating incentives for new entry in the upstream market to satisfy that demand. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).

7.457 If upstream producers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns will encourage new entry in the upstream market. The threat or event of new entry, in turn, would promote rivalrous behaviour in that market. Indeed, the mere reduction in impediments to entry could stimulate more competitive behaviour among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a).

7.458 The Council concludes that coverage is likely to promote upstream competition regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by upstream producers.

7.459 NECG argues that coverage would not promote competition in the way set out above. NECG claims that, even if coverage did cause a significant fall in delivered gas prices, it would not have a material impact on upstream competition (NECG 2002, sub.19, App.E, F).

7.460 The supporting arguments adopt two main themes:

(a) any stimulus to upstream competition arising from lower MSP tariffs would be negligible due to inelastic demand and the small proportion of delivered gas prices accounted for by transmission tariffs.

(b) there are extant barriers to competition in the Cooper Basin that would impede any promotion of competition.

Materiality issues

7.461 NECG argues that coverage would not have a material impact on demand for gas. In particular, NECG argues that even if coverage resulted in MSP tariffs being reduced to those proposed by the ACCC (the maximum likely price change if the MSP was covered), this would have “no impact” on upstream competition (NECG 2002, sub.19, App G, p.14). NECG argue that because the sensitivity of final demand to transport costs is small, any possible stimulus to upstream competition would be minimal.[136]

7.462 NECG states that lower transport tariffs could result in one of three scenarios (or a combination of all three):

(a) retail prices fall;

(b) retail margins rise;

(c) producer margins rise.

7.463 NECG argues that even if retail prices fall, inelastic demand for pipeline services will severely limit any stimulus to the demand for gas. In addition, as transmission tariffs make only a small part of delivered gas prices, the price impact itself will be small. NECG estimates that the removal of all monopoly rents identified by the ACCC would reduce delivered gas prices by about 4% and boost downstream demand by only 2%. Part of this stimulus may be filled by Gippsland Basin gas, further limiting any stimulus to upstream competition. NECG argues that, given the additional problem of significant barriers to upstream competition:

> *It seems implausible to suggest that very minor changes in final demand, even if they were to occur, would or could materially alter the height of entry barriers and thereby affect entry. To suggest that a once-off 2 per cent demand increase would induce material entry, or in any other way intensify competitive pressures, requires making assumptions about market structure that are extreme and completely unsubstantiated...* (NECG 2002, sub.19, App. G, p.14).

7.464 NECG argues that the second scenario – higher retail margins – is unsustainable, as margins would soon be competed away by new entry in the retail sector. Thus, scenario two would eventually revert to scenario one.

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136 NECG also raise other arguments on this matter, covered elsewhere in this report. The arguments relate to; scope for the Cooper Basin producers to defeat price rises on the MSP by diverting sales to markets outside NSW/ACT or by reducing production at Moomba; the existence of extant barriers to competition in the upstream market; and the risk of collusion between the MSP and the Cooper Basin producers (which NECG argues is implausible). See paragraphs 7.132 to 7.196 and 7.473 to 7.489.

7.465 The Council observes that new entry in gas retailing is a pro-competitive outcome, and in itself, suggests that coverage would promote competition.

7.466 More generally, the Council notes that NECG's analysis relies on similar logic to the claim that removal of monopoly rents would not have a material effect on downstream markets. In both the upstream and the downstream case, NECG's claim is largely based on quantitative analysis that removal of monopoly rents would have no discernible impact on the final demand for gas.

7.467 The Council noted a number of concerns regarding NECG's methodology in its assessment of the downstream case. The Council considers that NECG understates the reduction in delivered gas prices that would flow from coverage; and also understates the likely elasticity of gas demand among major gas users (see paragraphs 7.419 to 7.430). The Council's concerns also apply to NECG's assessment of the upstream case.

7.468 In addition, the Council observes that NECG extrapolates its analysis of downstream market conditions into the upstream market, without taking into account important differences in market dimensions. In particular, NECG adopts an industry-wide estimate of demand elasticity to analyse the impact of a price change on upstream markets.

7.469 The Council considers that while it is industry-wide demand for gas that affects entry incentives in the downstream market, scope for substitution can intensify the impact of a price movement on demand for gas from a particular basin. In this sense, the impact of a price shift may be more significant upstream than in the downstream market.

7.470 The NECG elasticity data derives from statistics covering the years 1973-74 to 1993-94. During those years, a price reduction on the MSP would have left gas buyers in NSW/ACT without viable substitution possibilities because no other transmission pipeline served that market.

7.471 However, it is likely that construction of the EGP has improved substitution possibilities between gas basins.[137] For this reason,

[137] This does not indicate that downstream competition is effective; that is, it does not suggest that monopoly rents have been competed away.

lower prices for MSP services are likely to result in both an increase in downstream market demand for gas (which NECG acknowledges) as well as some substitution from Gippsland Basin gas to Cooper Basin gas (which NECG does not appear to take into account). That is, removing rents from pipeline tariffs would induce a sharper rise in demand for Cooper Basin gas than NECG claims. In this sense, NECG understates the promotion of upstream competition.[138]

7.472 Given the flaws in NECG's analysis, the Council does not accept the NECG claim that coverage would have no effect on upstream competition.

Extant barriers to competition in the Cooper Basin

7.473 NECG argues that extant entry barriers in the Cooper Basin, would defeat any potential impact of coverage on upstream competition – in the sense that those extant barriers would remain even if the MSP was a covered pipeline.

7.474 NECG and EAPL note that the Upstream Issues Working Group (**UIWG**) reported a number of upstream barriers to competition, including acreage management policies, access to upstream facilities and joint marketing arrangements. They argue, however, that UIWG did not identify access to pipelines (or high pipeline tariffs) as a barrier to upstream competition.

7.475 The Council is cognisant of the barriers to competition identified in the UIWG report. The Council notes that the report was written on the assumption that the National Gas Code would apply to major gas pipelines. The report therefore focuses on issues other than pipeline access (UIWG 1998, pp.7).

7.476 The Council further notes recent progress towards addressing the barriers identified by UIWG. In particular, regulatory reform in South Australia has led to acreage management reforms in the Cooper Basin since 1999. Prior to 1999, exploration acreage had not been allocated to any party other than Santos and its joint venture

[138] While a price reduction for MSP services may promote competition and new entry in the Cooper Basin, it may also weaken entry incentives in the Bass Strait production market (because some demand would shift to a competing supplier). Ordover and Lehr recognise the possibility of differential impacts on different markets. They state: "Interestingly, it is conceivable that criterion (a) might be satisfied if it were found to lower entry barriers in at least one market, while increasing entry barriers in another" (Ordover and Lehr 2001, p.11).

partners. Since 1999, several blocks have been reallocated to new entrants in the Cooper Basin (see paragraph 4.24).

7.477 According to the Commonwealth Department of Industry Tourism and Resources:

> *Reforms in South Australia have already resulted in greater diversification of exploration tenement holders in the Cooper Basin, with 27 new petroleum exploration licences having been awarded to companies in the Basin since the expiry of pre-existing licences in February 1999. These licences were awarded to a total of 14 different companies and consortiums, most of them new players in the Cooper Basin* (Industry Tourism and Resources 2002).

7.478 The Department reports that the reforms are expected to achieve greater competition in gas production in the longer term. Indeed, considerable new exploration is now underway in the Cooper Basin to exploit additional reserves. In 1999-2000, the South Australian Government tendered exploration rights to 27 blocks, with six more blocks tendered in September 2001. The South Australian Minister for Minerals and Energy announced in October 2000 that more than $240 million had been pledged to explore for new gas reserves in the Cooper Basin over the next five years (SA Minister for Minerals and Energy 2000). Much of this expenditure is being committed by exploration companies not previously operating in the basin, including Stuart Petroleum, Beach Petroleum, Magellan Exploration, and Australian Crude Oil (which have collectively been awarded 12 of the first round of 27 new blocks). These new entrants are independent of the existing producers in the Cooper Basin, the SACBUP and SWQ Producers (Primary Industries and Resources SA 2001b).

7.479 In 2002, new entrants in the Cooper Basin made oil discoveries at Acrasia-1, Acrasia-2 and Sellecks-1, with production from some wells expected to follow soon. The new discoveries are located within an 85 km radius of the Moomba production facility. Further exploration work is continuing elsewhere in the Basin (Beach Petroleum 2002b, 2002c, 2002d).

7.480 The Council understands from discussions with Primary Industries and Resources SA that the new entrants have focussed their exploration work to date on petroleum, but that gas discoveries are likely as a by-product of this exploration work. Primary Industries and Resources SA has indicated to the Council that gas discoveries could take 3-5 years, but could be much sooner.

7.481 NECG argues that the South Australian reforms have limited value:

> *Given these (1999) blocks were based on relinquished blocks, it would be expected that previous exploration would have identified the largest fields and thus subsequent discoveries would likely be relatively small* (NECG 2002, sub.19, App. G, p.6).

7.482 The "promotion of competition" test assesses whether coverage would make the dependent market more conducive to competitive behaviour and new entry. The Council considers, as a general principle, that the removal of one barrier to competition is a positive step towards promoting competition, even if some other issues may remain. A progressive removal of barriers may be sufficient to encourage market entry or exercise discipline on incumbent producers.

7.483 The Council accepts that the upstream gas sales market in the Cooper Basin is not effectively competitive at present. However the progressive removal of barriers to entry in the Cooper Basin has been sufficient to encourage substantial steps towards market entry and may exercise increasing discipline on incumbent producers over time. In this sense, the Council does not accept the proposition that the upstream market has such insurmountable barriers to entry that coverage would fail to promote competition. On the contrary, the Council considers regulated access to the MSP at efficient tariffs as one factor – complementing regulatory reform – that is likely to encourage ongoing new entry in the upstream market.

7.484 The Council reiterates, in this regard, that criterion (a) focuses on the environment for competition, rather than the achievement of immediate outcomes. As Ordover and Lehr point out, achieving greater depth in the upstream competition may be a gradual process:

> *A reduction in entry barriers in either an upstream or downstream market need not automatically induce new entry. Because of other market frictions, entry may be slow in coming. Hence, criterion (a) cannot be taken to mean that coverage would rapidly induce entry relative to the no-coverage benchmark. Rather, we take the criterion to mean that coverage is justified if imposition substantially increases the overall competitive conditions in relevant market(s), including the likelihood of entry. Here, it is important to point out that the mere reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers...* (Ordover and Lehr 2001, p.11).

7.485 A threshold issue is whether access under the Code would be a significant issue for the new entrants. Should new entrants make significant gas discoveries (as is plausible), there is likely to be an interest among new entrants in marketing gas directly. Pipeline access would then be a critical issue because regulated access may determine whether gas can be shipped to customers on reasonable terms and conditions. In turn, this may affect the ability of new entrants to compete against incumbent producers in the upstream gas sales market. Access on reasonable terms and conditions may therefore have a significant bearing on entry incentives in the upstream market.

7.486 If new discoveries were relatively small, a possible scenario is for new entrants to sell the gas to incumbent producers, especially if potential customers are locked into pre-existing contracts. This would also obviate the need for new entrants to invest in production facilities and marketing services. However even in these circumstances, the availability of pipeline access would be significant. Coverage guarantees a right to access spare pipeline capacity on regulated terms and conditions, including a cost-based price. Having this option as a “back up” would assist small producers in negotiating reasonable terms with incumbent producers. In the absence of coverage, new entrants may have no choice but to enter potentially costly negotiations with incumbent producers, with a genuine risk of a satisfactory outcome not being reached.

7.487 The Council notes that Beach Petroleum, a new entrant in gas exploration in the Cooper Basin, has indicated that access to transmission pipelines may be a significant factor in the commercial viability of new exploration and development programs. According to Reg Nelson, CEO of Beach Petroleum:

> *Any new discoveries would be advantaged commercially by access to the region's existing and well developed transmission and processing infrastructure* (Beach Petroleum, 2002a).

7.488 The Council accepts that coverage of the MSP would improve commercial prospects for new entrants by providing them with a degree of countervailing power in negotiations with incumbent producers. Coverage therefore improves the commercial viability of new entry in the upstream market. This, in turn, promotes upstream competition by encouraging new entry in gas exploration. The Council observes that even if gas discoveries are ultimately sold to incumbent producers, the promotion of new exploration activity and increased gas production is a pro-competitive outcome, reflecting an improved competitive environment.

7.489 The Council concludes that coverage of the MSP would promote upstream competition by removing barriers to entry in the upstream market. In particular, coverage would provide better opportunities for new entrants to market their gas, either to gas customers or to incumbent producers. This environment is likely to encourage new exploration activity, competition between new entrants and incumbent producers and higher rates of gas production. These would be pro-competitive outcomes. Conversely, should access be foreclosed, the introduction of greater depth and competition in the upstream market would be inhibited.

Promotion of upstream competition: concluding comments

7.490 The Council considers that coverage would remove a barrier to entry imposed by monopoly pricing on the MSP. In particular, coverage would provide upstream producers and gas buyers with a right to access spare capacity on the MSP at an efficient price set by an independent regulator. The ACCC draft indicative tariffs (adjusted) indicate that this price would be significantly lower than prices absent coverage.[139] The Council considers that competition would be promoted regardless of whether lower transport tariffs are passed on to customers, or are expropriated in the short run by producers.

7.491 The Council has examined claims that the promotion of competition arising from coverage would be negligible because of inelastic demand and the small proportion of delivered gas prices accounted for by transmission tariffs. The Council considers that these claims are likely to rely on understated estimates of relevant demand elasticities and the relative cost of transmission services.

7.492 The Council has also examined claims that any promotion of competition in the upstream market would be defeated by barriers to competition related to acreage management. The Council has found that acreage management policies have been progressively reformed since 1999, and has noted the entry of several producers independent of the incumbents. Over time, these parties may exercise increasing

[139] The price differential may be greater than the gap between current MSP tariffs and the adjusted draft indicative tariffs proposed by the ACCC. There is potential scope for MSP tariffs absent coverage to rise above current levels, due to a recent rise in EGP tariffs. EGP tariffs will rise again in January 2003. See footnote 80.

discipline on the upstream market, stimulating increased gas production from the Cooper Basin and, possibly, more producers in the long run.

7.493 Coverage of the MSP is likely to encourage ongoing new entry in the Cooper Basin by improving commercial prospects for selling gas. In the event of large discoveries, coverage would provide a means for gas to be shipped to customers on competitive terms. If discoveries are small, new entrants may prefer to sell gas to incumbent producers. Once again, coverage would improve commercial prospects for new entrants by providing them with a degree of countervailing power in negotiations with incumbent producers. For these reasons, coverage is likely to encourage new exploration activity, competition between new entrants and incumbent producers and higher rates of gas production. These would be pro-competitive outcomes.

7.494 The Council therefore remains satisfied that coverage of the MSP would promote competition in the Cooper Basin gas sales market.

Ordover and Lehr (b): Ability to engage in price coordination

7.495 Ordover and Lehr's second line of inquiry for gauging the MSP's ability to exert market power in a dependent market focuses on whether the MSP can jointly implement monopoly pricing through implicit or explicit collusion with other pipelines serving downstream markets. The "other" pipeline in this context is the EGP.

7.496 The Council reiterates that competition between the MSP and the EGP is derived from competition between bundled products of delivered gas in downstream gas sales markets (see paragraphs 7.199 to 7.205). The potential for parallel pricing behaviour between the pipelines should also be viewed in this context. For example, parallel behaviour would not require MSP tariffs to directly match EGP tariffs if there are differences in well-head gas prices between the Cooper Basin and Gippsland Basin fields. Instead, parallel behaviour might involve pricing strategies that result in parity in delivered gas prices, while allowing the MSP and EGP to earn above-competitive returns.

7.497 A number of parties have raised concerns about parallel pricing behaviour between the MSP and EGP. For example, the Energy Markets Reform Forum argued that coverage of the MSP would intensify competitive disciplines on the EGP by lowering (regulated) delivered gas prices in Sydney. According to the EMRF, revocation would ease this pressure and make collusion more likely:

> *…from Duke's point of view, having sunk its money, it must now make a profit and the best means to do so seems to operate in tacit collusion with the original incumbent monopolist… In short Duke does not want to be forced by regulation to compete with a low cost incumbent producer: it naturally wants high haulage prices for both EAPL and itself* (EMRF 2001, sub.14, p.11).

7.498 Below, the Council considers the risk of parallel behaviour; and whether coverage of the MSP pipeline would reduce the risk of such behaviour.

Risk of parallel behaviour

7.499 Incentives for parallel behaviour between pipelines may arise from inelastic demand for natural gas (Ordover and Lehr 2001, p.22). The Council has found that demand for gas in NSW/ACT downstream markets is likely to be relatively inelastic, although is likely to be becoming less inelastic over time (see paragraphs 7.419 to 7.430).

7.500 The risk of parallel behaviour is further increased if competition in upstream or downstream markets is limited (Ordover and Lehr 2001, p.14). The Council concluded in paragraphs 7.196, 7.313 and 7.402 that neither the upstream Cooper Basin market nor downstream NSW/ACT gas sales markets are effectively competitive at present.

7.501 The risk of parallel behaviour also tends to be greater if few pipelines serve relevant markets (Ordover and Lehr 2001, p.14). However the existence of a small number of participants does not necessarily mean that parallel behaviour will occur.

7.502 Conversely, the following factors may reduce the risk of parallel behaviour between pipeline owners:

(a) excess pipeline capacity;

(b) the ability to price discriminate such that deals unlikely to be observed by competitors can be offered to customers; and

(c) high volume long term supply contracts.

7.503 The Council notes that the evidence on each of these factors tends to suggest a reduced risk of parallel behaviour between the MSP and the EGP. In particular:

(a) the MSP and EGP (the largest pipelines serving Sydney and Canberra) have significant excess capacity.

(b) the MSP and EGP have a stated commitment to publish non-discriminatory tariffs. This could make price discrimination relatively difficult to sustain.

(c) long-term contracts and large-scale purchases are a feature of dependent markets.

7.504 Despite these mitigating circumstances, Ordover and Lehr conclude from the facts, that in the context of the MSP applications:

> *public policy concerns regarding co-ordinated pricing cannot be dismissed out of hand* (Ordover and Lehr 2001, p.14).

Coverage and the risk of parallel behaviour

7.505 NECG/EAPL concede that several factors typically associated with collusion are evident in the pipeline services market, but argue that the conditions for collusion are more readily apparent where the pipeline is covered. In particular, NECG has argued that the Gas Code's information disclosure requirements, may enhance the risk of collusion.[140] The Tribunal considered this matter in the *Duke EGP decision*:

> *Mr Ergas said that they (the Code's information disclosure requirements) enable pipeline operators to know the intentions of competitors with respect to future capital expenditure and volumes (market share) and therefore provide the ability to set prices in concert...* (Duke EGP decision 2001, paragraph 114).

7.506 The Tribunal agreed with this view, at least partly as a consequence of its finding that the EGP does not have market power (*Duke EGP decision 2001*, paragraph 115).

7.507 The impact of information disclosure mechanisms is relevant to both criteria (a) and (d). The Council canvasses the issues more fully under criterion (d), but for the purposes of criterion (a), the Council notes the views of Ordover and Lehr that coverage is likely to reduce the risk of collusion by constraining prices to cost-based levels. Ordover and Lehr consider that this could have a salutary effect on pipeline tariffs (Ordover and Lehr 2001, p.14).

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140 sub. 9, p. 24.

The Tribunal's approach to collusion

7.508 Duke Energy argues that the Tribunal was not persuaded that parallel pricing between the EGP and other pipelines was a significant risk in the Duke EGP decision 2001. By implication, it would be therefore be inappropriate to regard parallel pricing as an issue with regard to the MSP. According to Duke:

> *Since DEI has been found not to have an incentive to engage in explicit or implicit price collusion, with whom is EAPL going to collude in relation to prices?* (Duke Energy 2002, sub.21, p.10)

7.509 It is not clear the extent to which the Tribunal's finding on parallel pricing is derived from its view that the EGP lacks significant market power. To the extent that it is so derived, the context of the present application involves different considerations. The Council further notes that while the Tribunal did not reach an affirmative finding on parallel pricing, it did not rule out the risk of such behaviour.

Ability to engage in price coordination: conclusion

7.510 The Council considers that parallel behaviour between the MSP and EGP is potentially profitable to the parties, and notes Ordover and Lehr's view that coverage is likely to reduce the risk of collusion and could have a salutary effect on prices. In particular, the Council notes that by providing a regulated right for third parties to access spare pipeline capacity at an efficient price, coverage would make collusion unprofitable

7.511 The Council also considers that a number of facts mitigate against the likelihood of effective collusion in this instance. As there is no evidence of parallel behaviour between the MSP and EGP, the Council has a neutral view as to whether coverage would mitigate the risk of such behaviour.

Ordover and Lehr (c): Vertical leveraging

7.512 The third matter identified by Ordover and Lehr as relevant in an assessment of criterion (a), is a consideration of other incentives and opportunities for the MSP to distort competition in upstream or downstream markets. That is, what would be the scope for the MSP to use its market power in the transport market to distort competition in upstream or downstream markets absent coverage?

7.513 The Council notes that the possibility of a distortion of competition arising from leveraging market power or from some form of vertical integration, whether through complete or partial ownership interests or through other arrangements, are not unique to access regulation. These issues are the subject of economic literature and judicial consideration in the context of misuse of market power. Whilst each specific case must be examined in the particular legislative context, assistance can be obtained from examining the treatment of this issue in other contexts.

7.514 For the purposes of assessing the impact of any vertical linkages on competition in another market with or without coverage, the Council notes that currently, the MSP is a covered pipeline under the Code. However, no Access Arrangement has been approved by the ACCC (although an Access Arrangement has been submitted and the ACCC has issued a draft decision in relation to that proposed Arrangement). This means that, currently, there is no minimum reference tariff and terms and conditions on which the MSP is required to provide gas transportation services to third parties.

7.515 However, the MSP as a covered pipeline is subject to the provisions of the Code, including the ringfencing obligations and Associate Contract provisions. The Council has taken these obligations into account in considering the effect of the Gas Transportation Deed, with or without coverage (see paragraphs 7.593 to 7.616). In particular, in its assessment of the Gas Transportation Deed, the Council has taken into account the Code's requirements for approval of Associate Contracts.

The economics of vertical leveraging

7.516 A pipeline with monopoly power over transport may seek to leverage its market power into upstream or downstream markets, to maximise the value of its assets. Specifically, if a pipeline has ownership interests in upstream or downstream markets, it may have an incentive to discriminate in favour of its affiliate:

> *... if the pipeline has a subsidiary operating in the downstream market, the pipeline may seek to use its control over transportation facilities to disadvantage its downstream rivals.* (Ordover and Lehr 2001, p.11)

7.517 Discrimination can manifest in a variety of ways, including:

(a) charging lower prices to affiliates for transport services; or

(b) offering services on unequal and inferior terms to non-affiliates in the upstream or downstream market.

7.518 Vertical leveraging of this kind may hinder competition in dependent markets. For example, it may deter the prospect of entry by independent parties into those markets.

7.519 That is not to say that discrimination always reduces economic efficiency and harms consumers:

> *For example, by advantaging its affiliate(s), the vertically-integrated incumbent may put enhanced competitive pressures on its stand-alone competitors in the upstream or downstream markets.* (Ordover and Lehr 2001, p.15-16)

7.520 There is also an important distinction between an incentive to inhibit competition and the exploitation of economic efficiencies sometimes associated with vertical integration:

> *... it must be recognized that the technical aspects of gas transport (such as the need to balance the network and control injections into and withdrawals from the pipeline) can cause the pipeline owner to favor its affiliates for reasons that have nothing to do with the incentives as described above but, rather, for reasons that are firmly grounded in pipeline economics. When such discrimination arises as a consequence of the efficiencies of vertical integration, overall efficiency would be harmed if the integrated pipeline could not extend preferential benefits to its affiliates.* (Ordover and Lehr 2001, p.16)

7.521 Ordover and Lehr argue, nonetheless, that coverage criterion (a) is likely to be satisfied if coverage lessens opportunities for differential treatment of vertically related parties:

> *Criterion (a) ... asks whether coverage of the pipeline would reduce entry barriers in at least one upstream or downstream market... Thus, if for example, coverage lessens the opportunities for anticompetitive differential treatment of firms that compete with the subsidiaries of the pipeline, the effects of coverage on competition may be quite salutary.* (Ordover and Lehr 2001, p.24)

7.522 Absent coverage, the principal constraint on discriminatory behaviour is effective competition in source and destination markets. According to Ordover and Lehr:

> *To evaluate the... competitive dangers, it is necessary to consider the competitive conditions in the upstream and downstream markets. For example, if the pipeline has a subsidiary operating*

> *in the downstream market, the pipeline may seek to use its control over transportation facilities to disadvantage its downstream rivals. Whether the pipeline could be effective in such a strategy will depend on the strategic alternatives available to the pipeline's downstream rivals (e.g., the opportunity to switch to gas supplied by the EGP or the Interconnect would reduce any potential anticompetitive impact from discrimination by the MSP).* (Ordover and Lehr 2001, p.11)

7.523 Ordover and Lehr also observe that:

> *… to the extent that competition in the source and destination markets is at least reasonably effective, the concerns with anticompetitive leveraging (hence the need for active regulation) are commensurately lessened…*(Ordover and Lehr 2001, p.15)

7.524 Effective competition between alternative inputs is also recognised by Scherer and Ross as a constraint on the ability and incentive of an input monopolist, such as a pipeline, to engage in vertical leveraging to adversely effect competition in a dependent market. Scherer and Ross express the argument made by Ordover and Lehr in terms of the elasticity of substitution between a monopolised input (e.g. gas transported via, and the gas transportation services provided by, the MSP) and alternative inputs (e.g. the opportunity to switch to gas supplied by the EGP) as follows:

> *If the substitution elasticity's value is well above 1.0, other inputs will displace the monopolized input when its price is elevated only modestly above competitive levels, so the monopolist's cost advantage will be small.* (Scherer and Ross 1990, pp.524-525)

7.525 An elasticity of well above unity implies effective competition between the MSP and its rivals in the source or destination market (provided that elasticities are measured at 'competitive' price levels – see paragraph 7.543). The Council elsewhere examines competitive conditions in markets upstream and downstream of the MSP (see paragraphs 7.128 to 7.314). The Council found that:

(a) downstream markets have been exposed to increased competition since the opening of the EGP, but that those markets remain very concentrated, with a dominant incumbent continuing to supply most of the retail market; and

(b) while the upstream market has become more contestable since regulatory reform commenced in 1999, the MSP retains a high degree of monopsony power due to the limited options open to the Cooper Basin producers to ship gas to alternative markets. While this may change in the medium to longer term (the proposed SEA Gas pipeline is likely to make increased sales to South Australia more feasible), the Council notes that the ability to make such diversions may be constrained by demand and supply conditions in the alternative destination markets.

7.526 Given that dependent markets are not effectively competitive at present, there is no competitive constraint on anti-competitive leveraging in this instance. Whether there is a genuine risk of leveraging turns on the opportunities and incentives facing the relevant parties. The Council now turns to consider the ability and incentive for the MSP to engage in vertical leveraging.

7.527 NECG argues that vertical leveraging is not in the interests of a monopoly pipeline owner if the input it supplies is used downstream in fixed proportions. NECG further argues that such conditions apply in downstream gas markets, citing the absence of economic substitutes for natural gas in most instances. This means that the amount of natural gas required to produce a given output is relatively fixed:

> *Under such conditions (in most cases), even a monopolist in gas transportation could extract no greater profit from integrating upstream or downstream. Thus, it would be in the monopolist's best interest to promote competition among downstream users, as that would maximise usage of the pipeline and thereby the pipeline's profits.* (NECG 2002, sub.19, App. D, p.3)

7.528 Utton articulates the economic theory underpinning NECG's argument in the following way:

> *Until comparatively recently, it was thought that a monopoly input supplier had no profit incentive to integrate forwards to take over a competitive industry. The monopolist could sell at a monopoly price, which would be incorporated in the product price of the competitive firms. Any increase in price by the monopolist would have to be accepted by the competitive firms. The monopolist could wring out all of the monopoly profit available by selling at the monopoly price.*
>
> *This result, however, depends on the downstream competitive industry... having a fixed proportions production function; that is, at any level of output there is a unique optimum combination of inputs, with no possibility of substitution.* (Utton 1995, p.214)

7.529 Strictly, the NECG argument is not an accurate application of the "one monopoly rent theory" outlined by Utton. NECG argues that, ultimately, the monopolist will maximise profits by maximising utilisation of the infrastructure, whereas the "one monopoly rent" theory merely suggests that, in some circumstances, the monopolist can derive all the rents available without vertical leveraging.

7.530 As explained by Scherer and Ross the monopolist would, in the circumstances indicated by NECG, restrict output:

> *For wherever it is in the chain, the monopoly can take full advantage of all output-restricting, profit-enhancing opportunities by correctly deriving its own monopoly demand function from the demand functions and costs of competitive stages nearer the consumer, that is, downstream.* (Scherer and Ross 1990 p.522)

7.531 NECG also concedes that there is an incentive for vertical leveraging if the monopolist can price discriminate between customers. Successful price discrimination requires the prevention of arbitrage and the inability of users to purchase from other suppliers. NECG argues, however, that these conditions for price discrimination do not apply to the MSP because of:

(a) scope for arbitrage via the local distribution network; and

(b) the availability of competing supplies of gas from the Gippsland Basin.

7.532 The Council does not accept NECG's proposition that the MSP has no incentive to engage in vertical leveraging for at least the following two reasons, which will be discussed in turn in greater detail below.

(a) The conditions underlying the "one monopoly rent" theory are not satisfied in respect of the MSP. Indeed, the Council considers that the MSP has the ability and incentive to engage in vertical leveraging to adversely effect competition in a dependent market in the circumstances under consideration.

(b) In any event, AGL has an incentive to adversely effect competition in the downstream gas sales market and is able to ensure, through its affiliate relationship with the MSP, that the MSP leverages its monopoly power into the downstream market to advantage AGL.

7.533 The Council considers that the conditions discussed by NECG and Utton, under which an input monopoly has no incentive to engage in vertical leveraging, are not satisfied in respect of the MSP. The Council considers that the existence of substitution possibilities between gas from the Cooper Basin and gas from the Gippsland Basin in the downstream market precludes a conclusion, based on the "one monopoly rent" theory, that vertical leveraging would not enhance MSP's monopoly power and profit-making opportunities.

7.534 The conditions necessary to found a conclusion that an input monopolist does not have an incentive to engage in vertical leveraging are rarely satisfied in the "real world." Scherer and Ross state that:

> *...the world is a good deal more complex than assumed in the models generating the [proposition that downstream vertical integration by a monopolist cannot enhance monopoly power and so profit-making opportunities]. In particular, those models ignore the possibility of substitution between monopolised and competitive upstream inputs, consider only the polar extremes of pure monopoly and pure competition, and abstract from market dynamics. Relaxation of the simplifying assumptions shows that monopoly power may be (but is not necessarily) enhanced through vertical combinations.* (Scherer and Ross 1990, p.522).

7.535 Scherer and Ross consider the effects of vertical integration by a monopoly input supplier where input substitution exists and conclude that monopoly power may be enhanced by vertical integration (Scherer and Ross 1990, p.523). In other words, there may be an incentive for vertical leveraging where input substitution exists. By extending its monopoly to downstream activities, the integrated firm gains control over the downstream industry's use of all inputs, and not merely the use of the monopolised input.

7.536 Significantly, NECG effectively concedes in arguing that the conditions for price discrimination are not satisfied in relation to the MSP that:

(a) there is some possibility of substitution, e.g. due to the availability of competing gas supplies from the Gippsland Basin; and

(b) therefore, the necessary conditions underpinning their argument that the MSP has no incentive to engage in vertical leveraging do not hold.

7.537 Scherer and Ross conclude:

> *Our analysis reveals that under plausible circumstances, vertical integration downstream by an input monopolist can lead to enhanced monopoly power and price increases.* (Scherer and Ross 1990, p.525).

7.538 The 'plausible circumstances' to which Scherer and Ross refer are actually circumstances in which vertical integration downstream by an input monopolist is likely to both enhance monopoly power *and increase prices* – that is, where the output reducing effect associated with an enhancement of the input monopolist's monopoly power due to vertical leveraging is likely to outweigh any output increasing effects associated with the efficiency benefits of vertical integration. Thus, it is highly likely that where these 'plausible circumstances' exist, there will exist an incentive for vertical leveraging due to the potential for enhancement of monopoly power. Indeed, an incentive for vertical leveraging due to its potential enhancement of monopoly power and profit maximising opportunities is likely to exist under far less stringently drawn conditions than Scherer and Ross' 'plausible circumstances'.

7.539 Scherer and Ross find that price increases, and by implication, an enhancement of market power, are almost certain to occur when an input monopoly vertically integrates downstream where:

(a) the elasticity of substitution between the monopolised input and a substitute input has a value of unity or above but not 'well above 1.0' at 'competitive' price levels; and / or

(b) the elasticity of substitution exceeds the downstream product's price elasticity of demand in absolute value.

7.540 Further, price increases are somewhat more likely, the less important the monopolised input is relative to other inputs – that is, where the monopoly input receives only a modest share of total input payments at 'competitive' price levels. Scherer and Ross explain that:

> *[t]he seeming paradox in this result is easily resolved when one recalls that integration downstream by an upstream monopolist extends the monopolist's usage control to other inputs, and the less important the originally monopolised input was, the more important the extension of control to other inputs.* (Scherer and Ross 1990, p.524).

7.541 This formulation of the 'plausible circumstances' can be applied to the circumstances of the MSP to conclude that it is more than likely that the MSP has an incentive for vertical leveraging to enhance its monopoly power and profit-making opportunities where:

(a) either or both:

(i) substitution between gas delivered from the Cooper Basin and gas delivered from Gippsland Basin or, in other words, gas delivered via the MSP and other pipelines has an elasticity of at least one (but not "well above 1.0") at competitive price levels; and / or

(ii) this elasticity exceeds the price elasticity of demand for the downstream product in absolute value; and

(b) the input provided by the MSP is a relatively unimportant input compared to other inputs.

7.542 The Council considers that there are a number of factors in this instance that make it difficult to reach a definitive conclusion with respect to satisfaction of the condition set out at paragraph 7.541(a)(i) above. While the available evidence suggests that the condition at paragraph 7.541(a)(i) may be satisfied and is certainly not inconsistent with the conclusion that there may be an ability and incentive to engage in vertical leveraging, the Council is wary of reaching a conclusion on the ability and incentive for the MSP to engage in vertical leveraging on the basis of condition (a)(i) alone.

7.543 First, satisfaction of the paragraph 7.541(a)(i) condition requires that the cross-price elasticity of demand between gas delivered via the MSP and gas delivered via other pipelines has a value of unity or above 'but not well above 1.0' *at competitive price levels*. An elasticity measured at 'monopoly' prices can be misleading. This is because the cross-price elasticity of demand facing a monopolist rises as its pricing increases above economic costs. A profit maximising monopolist will price up to the point where it is at risk of losing significant sales: by definition, lost sales such that overall profits would start to decline. Thus, a monopolist pricing at the profit-maximising point faces a cross-price elasticity of demand that appears quite 'competitive' – that is, a cross-price elasticity of demand which is likely to significantly exceed unity. This, referred to as the 'cellophane' fallacy, is explained by Areeda and Hovenkamp in the following terms:

> *Actual trading patterns, cross-elasticity, and hypothetical price increases all delineate the market correctly when actual [product]* A *prices are at (or near) the competitive level but indicate overly broad markets when those prices have been significantly supracompetitive. The reason is easy to see. Buyers may have shifted to the [product]* B *firms precisely because the* A *price has been monopolistic and therefore has not been adequately*

> *constrained by competition from the* B *firms. At the profit-maximising price for product* A, *many customers are almost, but not quite ready to reduce their purchases or to find a substitute. Hence, cross elasticity of demand is surely high for the* A *firm(s) that have* already *maximised profits by balancing the gains from higher prices against the losses from sales to* B *or other firms. The observed high 'cross-elasticity of demand' between* A *and* B *then reflects not the absence of market power but its existence and exercise. The Supreme Court failed to recognise this in* its DuPont (Cellophane) case, *where the majority concluded that cellophane was not a relevant market because at current prices cross-elasticity of demand was very high with a variety of other flexible packaging materials.* (Areeda and Hovenkamp 2002, paragraph 539).

7.544 Significantly, the Council concludes at paragraph 7.402 that the MSP is likely to be engaging in monopoly pricing. Accordingly, this makes it difficult to reach a conclusion with respect to satisfaction of a condition which requires the cross-price elasticity of demand between gas delivered via the MSP and gas delivered via other pipelines to have a value of unity or above 'but not well above 1.0' *at competitive price levels*.

7.545 Coupled with this is an absence of reliable empirical data regarding the elasticity of substitution between gas delivered via the MSP and gas delivered via rival pipelines. The Council considers the available empirical evidence with respect to the cross-price elasticity of demand between the MSP and other pipelines at paragraphs 7.245 to 7.257 and concludes that no reliable empirical evidence is available.

7.546 As discussed at paragraphs 7.245 to 7.257 of this report, the Tribunal found in the *Duke EGP decision* that cross-price elasticities of demand between the EGP and the Interconnect were high. The Tribunal referred to a cross-price elasticity of demand between the EGP and the Interconnect of '2,' estimated by Mr Henry Ergas by SSNIP analysis. Similarly, Ordover and Lehr comment in the following terms on the cross-price elasticities between the MSP and competing pipelines:

> *Empirically, the ability of alternative sources of supply to offer effective competition would be supported by a finding that there is a high cross-price elasticity of demand associated with pipeline services offered by the MSP, EGP, or Interconnect; or in the delivered gas-prices for gas provided by the different pipelines in the NSW / ACT retail markets; or (less useful) in the well-head prices of gas produced in the Cooper or Gippsland Basins. While it seems plausible that the cross-elasticities are high, we are*

unaware of any empirical studies that provide a firm basis for gauging the size of the relevant cross-price elasticities. (Ordover and Lehr 2001, p.20).

7.547 However, as discussed at paragraphs 7.245 to 7.257, the Council considers that the SSNIP analysis used to estimate the cross-price elasticity of demand between the EGP and the Interconnect referred to by the Tribunal in the Duke EGP decision does not provide a sufficiently reliable basis on which to precisely calculate relevant elasticities. This was conceded by Mr Ergas in discussions with the Council and is the conclusion of Ordover and Lehr following consideration of the analysis.

7.548 Further, the cross-price elasticity of demand between the EGP and the Interconnect is not a reliable guide as to the cross-price elasticity between the MSP and the EGP. Given that the MSP provides different services to the EGP, the cross-price elasticity between the MSP and the EGP is likely to be lower than the cross-price elasticity between the EGP and the Interconnect.

7.549 It is possible, the Council considers, to conclude that the cross-price elasticity of demand between the MSP and other pipelines is unlikely to be "well above 1.0" at competitive price levels. A cross-price elasticity of "well above 1.0" at 'competitive' price levels would imply that competition between Cooper Basin gas and Gippsland Basin gas in the downstream gas sales market was effective. While the Tribunal in the Duke EGP decision found that the cross-price elasticities of demand between the EGP and other pipelines were high, the Council has found that there is not effective competition in the downstream gas sales market (for the reasons discussed in detail at paragraphs 7.197 to 7.314) and that the MSP is pricing its services at well above 'competitive' price levels. In particular, the Council notes evidence at paragraph 7.251 that the EGP does not regard the MSP as an effective constraint on its ability to raise prices at current MSP prices. These findings suggest that, although likely to be high at current price levels, the cross-price elasticities are not likely to be substantially above one at 'competitive' price levels.

7.550 The available evidence also suggests that the cross-price elasticity between the MSP and other pipelines may be unity or above at current prices. However, the Council does not consider that the available evidence is sufficient to reach any conclusion regarding condition (a)(i) at paragraph 7.541 with the required degree of confidence. In any event, the Council does not consider that condition (a)(i) is critical to a conclusion that the MSP has an ability and incentive to engage in vertical leveraging, as it considers that the alternate condition (a)(ii) at paragraph 7.541, together with the additional condition (b), are satisfied in respect of the MSP for the reasons discussed below.

7.551 The Council considers that the elasticity of substitution between gas delivered from the Cooper Basin and gas delivered from the Gippsland Basin is likely to exceed the price elasticity of demand for gas. That is, the condition set out in paragraph 7.541 (a)(ii) is likely to be satisfied.

7.552 As discussed at paragraphs 4.145 to 4.151, the most recent information available on the price elasticity of gas demand was prepared by ABARE for the Australian Gas Association (AGA 1996, p.29). The results indicate quite inelastic long-term demand in the manufacturing and commercial sectors, but reasonably elastic long-term demand in the residential sector. As the manufacturing and commercial energy users represent around 72.6% of total demand, the statistics suggest demand is relatively inelastic for the majority of demand. Specifically, the statistics suggest that an elasticity of demand of approximately 0.31.

7.553 While the Council recognises at paragraphs 7.419 to 7.430 that demand elasticity is likely to be considerably understated by the study due to, for example, subsequent technological change, the Council nonetheless considers it is unlikely that demand elasticity has increased to such a significant degree that it now exceeds the elasticity of substitution between gas delivered from the Cooper Basin and gas delivered from the Gippsland Basin. As observed at paragraphs 7.419 to 7.430, on the limited evidence available, it is reasonable to assume that demand for gas is likely to be relatively inelastic. In view of this, the available evidence with respect to cross-price elasticities of demand between the MSP and rival pipelines, while not reliable and possibly over-stated due to monopoly pricing by the MSP, allows the Council to conclude with a reasonable degree of certainty that the cross-price elasticities of demand between the MSP and other pipelines exceed the elasticity of demand for natural gas.

7.554 Finally, the condition set out at paragraph 7.541(b) is also likely to hold if, as was assumed by NECG, the application of this condition to the MSP is properly characterised as an inquiry into the importance of the input costs of MSP transportation services as a share of the total costs of gas supply to end-users, rather than the importance of the input costs of gas delivered by the MSP (including both commodity costs of gas from the Cooper Basin and the costs of MSP transportation services) as a share of the total costs of gas supply to end-users. As discussed at paragraphs 4.137 to 4.140, in 1999 NSW/ ACT transmission charges represented around 5% of the final price of gas for residential users, 12% for commercial and smaller industrial users and, possibly, up to 20% of charges for large industrial users. Thus, it is likely that the transportation service provided by the MSP is a relatively small to modest sized input (at least for residential, commercial and smaller industrial users) compared to other inputs in the supply of gas to most end-users. In any event, the point at paragraph (b) is not an essential pre-condition to concluding that the MSP likely has an incentive for vertical leveraging.

7.555 NECG raise the case of a "partial" vertical interest, citing Ordover and Baumol that this provides strong incentives to distort access to a bottleneck. NECG argues that this scenario does not apply in the current matter, noting that discrimination in favour of AGL is unlikely to be profitable for the MSP, given the likelihood of a fixed proportions production function and the constraints on price discrimination. That is, while leveraging may be in the interests of AGL, the interests of the MSP and its owners would be best served by maximising throughput on the pipeline.

7.556 NECG also argues that the MSP is not a bottleneck, noting the impact of EGP and the high cross-price elasticity between pipelines, as cited in the Duke EGP decision. In these circumstances, the ability to vertically leverage is weakened because discriminatory pricing against third parties would risk a loss of market share to the EGP. At the same time, discounting to AGL would result in direct losses to APT.

7.557 This argument merely asserts that the downstream gas sales market is competitive or, in other words, that cross-price elasticities between pipelines are not only high but "well above 1.0" (as discussed by Scherer and Ross in the extract at paragraph 7.524 above). As outlined by Ordover and Lehr, if dependent gas markets are competitive, then the ability of the MSP to charge monopoly prices and exploit market power will be constrained. For the reasons set out at paragraphs 7.544 to 7.549, the Council considers that the downstream gas sales market is not effectively competitive and that the cross-price elasticity of demand between the MSP and other pipelines is not likely to be "well above 1.0" at competitive price levels. In reaching this conclusion, the Council has had regard to the

Tribunal's comments in relation to cross-price elasticities of demand in the Duke EGP decision.

7.558 NECG concedes that, regardless of vertical links, it would be in the interests of AGL to distort competition in downstream markets – especially if the downstream market is not competitive and if customers lack substitution alternatives. But NECG argues that the strength of the incentive depends on the degree to which downstream markets are competitive. The Council has found elsewhere in this report that dependent markets are not effectively competitive, and as such, do not constrain the MSP's market power.

7.559 The Council considers that manipulation of MSP terms and conditions of supply and leveraging into downstream gas sales markets may enhance the ability of the MSP's downstream associate, AGL, to monopolise downstream gas markets by ensuring that AGL can make efficient choices between different sources of gas while the choices of gas consumers and competing wholesalers/retailers are distorted. This is because AGL's affiliate relationship can be used to ensure that gas supplies from the Cooper Basin are provided to AGL on terms and conditions more closely reflecting efficient costs compared to gas supplies to other parties.

7.560 The Council notes that, following their consideration of the circumstances of the MSP, Ordover and Lehr found that:

> *To the extent the MSP is vertically integrated into upstream or downstream services (and it appears that the MSP is extensively integrated into downstream markets via the AGL), there is also a public policy concern that it may engage in business strategies that could disadvantage non-integrated rivals. Maintaining coverage may lessen MSP's ability to deploy such strategies, but it is not without countervailing costs* (Ordover and Lehr 2001, p.24).[141]

Strategies

7.561 The Council considers that an incentive for the MSP to distort competition arises from the extent to which the MSP has:

(a) upstream or downstream affiliates; or

[141] The Council addresses the issue of "countervailing costs" under criterion (d): see section 9 of this report.

(b) is vertically integrated.

7.562 The Council considers that if the owners of the MSP have any interests in either the upstream or downstream markets, the owners will have an incentive to discriminate in favour of those interests, for example by charging lower prices for transport services provided by the MSP to an affiliate or by offering such services on inferior terms to non-affiliates in upstream or downstream markets. For example, if the pipeline owner has a subsidiary operating in the downstream market, the pipeline may seek to use its control over transportation facilities to disadvantage the downstream rivals of its subsidiary.

7.563 The Council has considered the extent of the MSP's interests in the upstream and downstream markets to determine whether the MSP will have an incentive to discriminate in favour of those interests.

7.564 In doing so, it has adopted the following approach:

(a) the Council has formed the view that:

(i) the fact that the owners of the MSP hold an interest in an entity which operates in another market does not, of itself, mean that they "control"[142] that other entity;

(ii) any entity in the upstream or downstream market which holds an interest in the MSP does not necessarily "control" the MSP;

(iii) there is a very close relationship between AGL and APT/APL/EAPL, arising from the factors set out in paragraph 7.577 below;

(iv) the factors set out in paragraph 7.576 below may lead to a conclusion that AGL has the capacity to control APL and EAPL;

(b) the legal restrictions on the MSP acting in a manner which benefits such an entity are detailed in Attachment 1 (confidential). Those legal restrictions focus on requiring conduct to be in the best interests of members of APT;

(c) those legal restrictions are unlikely, in many circumstances, to provide a constraint on the MSP acting in a manner to advantage an affiliate and so distort competition.

142 Applying the meaning of that term as used in the Corporations Act.

Upstream/downstream interests of MSP

7.565 Since issuing its draft recommendation in December 2001, the Council has received extensive submissions from APT, EAPL and other interested parties addressing the issue of whether the owners of the MSP have upstream or downstream interests and whether the MSP is part of a vertically integrated group. The Council has also sought independent advice in relation to that structure and the legal obligations of the owners of the MSP.

7.566 This information has clarified a number of issues raised in the draft recommendation. The legal owner of the MSP is EAPL. As set out in paragraph 4.86, the beneficial owner of the MSP is APT, a managed investment scheme of which APL is the responsible entity. The Council has formed the view that neither EAPL nor APT have any ownership interest in gas production or gas distribution.

7.567 The Council does not consider that the fact that the legal owner of the MSP has no ownership interest in upstream gas production or downstream gas distribution of itself results in a conclusion that the legal owner does not have incentives to prefer particular upstream or downstream interests nor that coverage would not promote competition in those markets. EAPL is clearly controlled by APL as the responsible entity of APT.

7.568 The various statutory obligations imposed upon APL, as the responsible entity and the officers of APL involve obligations to act honestly, exercise reasonable care and diligence and to act in the best interests of the members of APT. The nature and extent of those duties is such that:

(a) it would be a breach of those duties for APL as the responsible entity of APT to take a decision which advantaged AGL at the expense of the interests of the APT members;

(b) these duties would not prohibit APL taking a decision which was in the interests of the members of APT and also in the interests of AGL including advantaging AGL and/or its related bodies corporate to a greater extent than third parties.

7.569 These statutory obligations and duties do not apply directly to EAPL as:

(a) EAPL is not a responsible entity or trustee; and

(b) EAPL is not directly an asset of APT - however its holding company APT Pipelines Limited is an asset of APT.

7.570 However, given the overall structure of the arrangements, the Council expects that the board of EAPL would apply the same principles to decision making by EAPL.

7.571 The Council considers that an economic incentive which may result in the MSP acting in a way which distorts competition in the upstream or downstream markets may arise from a beneficial interest in the MSP held by an upstream producer or a downstream user.

7.572 As set out below, AGL owns 30% of the units of APT and 50% of APL. Two of the six directors of APL are AGL nominees. AGL therefore has ownership interests in the gas transport market (through its 30% ownership of APT) and the downstream market, through its ownership of AGLWG.

7.573 AGL also has in place a contract for the purchase of gas from SACBUP, the South Australian Cooper Basin Unit Producers (Letter of Agreement). From the material available to the Council, this appears to be AGL's only interest in the relevant upstream gas sales market. The Council also notes that AGL and APL have entered into the Pipeline Development Agreement, under which AGL agrees to offer to APT ownership of any gas transmission pipelines which AGL develops and that AGLIM (a wholly owned subsidiary of AGL) and APL have entered into the Pipeline Management Agreement under which AGLIM agrees to provide marketing and technical services to APL both for an initial period of 20 years, with subsequent rolling 5 year renewal terms.

7.574 EAPL has submitted that ownership interests are a legal matter and that the analysis of this question by Ordover and Lehr is therefore invalid (EAPL 2002, sub.19). The Council considers that this inappropriately aggregates two issues: the question of ownership or control in a strict legal context and the existence of facts relevant to the economic incentives the parties face. The precise legal ownership structure of the MSP does not invalidate the analysis of Ordover and Lehr. Ordover and Lehr's paper refers to the ownership interests of the "MSP", which is the abbreviation they use for the pipeline itself. The Council considers that the theoretical issue raised by Ordover and Lehr needs to be considered in relation to the MSP, in light of the details of the legal and beneficial ownership structure of all entities in the chain. In other words, the question at issue is to identify economic incentives for the MSP to distort competition in the upstream or downstream market. One such incentive may be the interest AGL has in the MSP and in AGLWG.

7.575 The Council considers that, to the extent to which the MSP is part of a vertically integrated entity, it may seek to extend, protect or exploit whatever market power AGL may have in either upstream or downstream markets. That is, the MSP may act in a way intended to protect AGL's market power as a buyer of gas in the upstream market or to protect, extend or exploit AGLWG's market power in downstream markets. Alternatively, its owners may seek to assert influence over APL/APT/MSP so as to advantage AGL's downstream interests, where such influence is permissible under the legal constraints including Corporations Act, Listing Rules and corporate governance of APL/APT. That is, AGL, as the 30% beneficial owner of the MSP, may seek to assert its rights as the major unit holder to cause the MSP to act in a manner which gives an advantage to AGLWG or which disadvantages AGLWG's competitors, for example, increasing the price for transport services via the MSP.

7.576 The Council considers that APL, as a matter of law, can discriminate in favour of AGL's interests upstream or downstream, provided such discrimination is not against the interests of all the unit holders in APT. The relevant question is whether AGL has the capacity to influence APL and EAPL. Factors which may lead to a conclusion that this is the case include the following:

(a) In addition to holding 50% of the shares in APL, AGL has the **[confidential information].**

(b) The joint capacity of AGL and the FHP Shareholders together to control the APL board. Based on current unitholdings in APT, the APL board is required to be comprised of up to 2 directors appointed by AGL, one director appointed by Petronas and 3 directors appointed pursuant to the APL Constitution. That provides that APL may by resolution in general meeting appoint or remove a director but it also gives the Board the power to appoint any person to fill a casual vacancy or as an addition to the existing directors **[confidential information]**. There are now 7 APL directors, **[confidential information]**.

(c) the investment characteristics of the APL shares held by the FHP Shareholders including:

(i) the illiquid nature of the investment;

(ii) the absence of value in the APL shares as APL has waived its right to receive management fees from APT above recovery of its costs **[confidential information]**;

(iii) the **[confidential information]** rights **[confidential information]**over the FHP Shareholders shares;

(iv) [confidential information].

(d) the other transaction documents which show a very close and long term arrangement between AGL and APT.

7.577 In addition to the corporate structure, there is clearly a very close relationship between AGL and APT/APL/EAPL arising from the following factors:

(a) APT has the right to acquire all or part of any new gas transmission pipeline opportunities developed by AGL and up to 20% of the PNG gas project;

(b) the parties agree to jointly seek out and examine opportunities to develop projects and to jointly acquire target businesses including gas transmission and distribution assets;

(c) subject to third party rights, AGL has a first right of refusal to provide pipeline management services to any pipeline APT acquires or in respect of which has sufficient influence to determine the appointment of an operator - as set out above, APL/APT control EAPL;

(d) subject to third party rights, APL has granted AGL pre-emptive rights so that it may not sell or otherwise dispose of any interest in any pipeline asset or shares in any company or units in any trust which directly or indirectly owns an interest in a pipeline. That is, the pre-emptive rights apply to, among other things, the shares in EAPL and EAPL's interest in MSP unless there are relevant third party rights;

(e) AGL has been retained by APL to provide business development services (relating to the acquisition, divestment or development of relevant business undertakings) for a minimum of $250,000 per annum for 5 years and potentially longer.

7.578 Whether or not AGL "controls" APL within the meaning of the Corporations Act and Listing Rules, the Council considers that the extent of AGL's ownership of and relationship with APT/APL/EAPL creates an incentive for APL to act in AGL's interests (provided that in so doing it is also acting in the interests of the APT unit holders as a whole).

EGP Decision

7.579 Some parties assert that, as APT (the legal owner of the MSP) has no interests in upstream or downstream markets, the MSP has incentives to maximise throughput, which is unlikely to distort competition in another market (AGA 2001, sub.8, p.3; NECG 2001, sub.9, pp.13,16,20). These assertions rely in part on the Tribunal's findings in relation to the EGP.

7.580 The Tribunal found that the EGP would not have sufficient market power to hinder competition for the following reasons;

(a) the commercial imperatives faced by the EGP;

(b) the countervailing power of other market participants;

(c) the existence of spare pipeline capacity; and

(d) the competition the EGP faced from the MSP and the Interconnect (*Duke EGP decision* 2001, paragraph 124).

7.581 Before reaching this conclusion, the Tribunal considered in detail the relationship between the operator of the EGP and its marketing associate, Duke Energy Australia Trading and Marketing Pty Limited (**DEATM**). The Council has considered this discussion in light of the ownership structure of the MSP and in light of the submissions received. The Council notes a significant difference between the relationship between the EGP and DEATM and the relationship between the MSP and AGLWG. The Tribunal noted that DEATM had entered into contracts with the Gippsland Basin producers for gas transported via the Interconnect, with the Gippsland Basin producers for gas transported via the EGP and with the MSP for Cooper Basin gas transported via the MSP *(Duke EGP decision*, paragraph 34). By contrast, AGLWG has a long term contact with the MSP for the transportation of gas from Moomba to Wilton which remains in place until 2016 (the Gas Transportation Deed, discussed below). As far as the Council is aware, AGLWG does not have in place any contracts with the Gippsland Basin producers or with the EGP or Interconnect. AGLWG has not provided any details of any such contracts to the Council.

7.582 In addition, the Council notes that while a significant proportion of MSP capacity is contracted to AGLWG, especially until 2006, the EGP does not have contractual arrangements of this magnitude with DEATM. Currently, gas delivered by the MSP for AGLWG **[confidential information]**of the total gas deliveries in NSW (EAPL 2002).

7.583 The Council considers that these factual differences require the Council not merely to apply to the MSP the decision the Tribunal reached in relation to the EGP but to consider whether and to what extent the elements set out above are present in relation to the MSP.

Effect of strategies on competition without coverage

7.584 Having identified an incentive for the MSP to discriminate in favour of AGL, the Council has considered whether:

(a) the MSP could be effective in a strategy designed to disadvantage upstream or downstream rivals of AGL and its affiliates – this depends on the strategic alternatives available to those rivals (eg the opportunity to switch to gas supplied by the EGP or the Interconnect would reduce the potential anti-competitive impact from discrimination by the MSP).

(b) such a strategy, if implemented, would be likely to distort competition in the upstream or downstream market absent coverage.

(c) if the answer to questions (a) and (b) above is yes, whether coverage would result in either the inability of the MSP to adopt those strategies or a reduced likelihood that those strategies would be adopted.

Assessment of likely effect of these strategies on competition in upstream market absent coverage

7.585 AGL's interest in the relevant upstream gas sales market is limited to its interest as the purchaser of gas from the South Australian Cooper Basin Unit Producers (SACBUP) under the Letter of Agreement. The SACBUP is a consortium of companies, the principal member being Santos Ltd (*Duke EGP decision*, paragraph 7). In 1971, AGL negotiated a letter of agreement with the Cooper Basin producers selecting them as the long term source of supply of natural gas to Sydney (at that time, AGL supplied gas to all retail customers in NSW). That Agreement expires in 2006 (with a possibility of a further extension of up to 5 years). Under the Letter of Agreement, the Cooper Basin producers are bound to supply to AGL, and AGL is bound to purchase from the Cooper Basin producers, 80% of its requirements for natural gas [for sale in NSW] at least until 2006 at prices determined in accordance with that agreement.[143]

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[143] Re: Application for Review of Determination of the ACCC made on 27 March 1996 revoking Authorisation No. A90424 and Granting Further Authorisation (AGL Cooper Basin Natural Gas Supply Arrangements) Australian Competition Tribunal VG 1 OF 1996 14 October 1997 pp 7-11.

The Council notes the following provisions of the Letter of Agreement between the Cooper Basin producers and AGL:

1. The term of the Letter of Agreement is an initial period of 30 years from the commencement of supply (1976) (cl 16) with provision for the extension of the Agreement for no more than five years (cl 18).

2. Clause 18, the “take-or-pay” clause”, provides as follows:

(a) In each contract year AGL was bound to either take or pay for 80% of the prescribed annual volume of gas.

(b) To the extent that it paid for gas but did not take it, this gas could be taken free of charge in some later year (“banked gas”).

(c) When banked gas was taken in a particular year it was not to be counted as portion of the 80% for that year.

(d) Any gas taken by AGL over and above the prescribed annual volume was, in the first instance, to be taken from any current banked gas entitlement.

(e) Any residual banked gas credit remaining at the end of the 30-year term had to be supplied over the next five years without cost to AGL, subject to a prescribed supply formula.”

7.586 The Council notes that the Tribunal in the EGP decision considered that long term contracts such as the contract between AGL and the Cooper Basin producers "are not completely inflexible eg the contracts can include price review clauses which are triggered by the price of other sources of gas" and concluded that long term contracts do not restrict competition to any great extent (*Duke EGP decision* paragraph 105).

7.587 However, the Tribunal did not consider the effect of a long term contract between a producer located at a particular gas production field and a customer, where the customer is located in NSW/ACT, for the producer to supply gas to that customer at that destination, effectively requiring that gas to be transported using the only pipeline which connects that producer to that customer (ie the MSP).

7.588 The Council notes that the Letter of Agreement contains price review clauses and various other flexible provisions of the kind noted by the Tribunal above.

7.589 AGL's only interest in the relevant upstream gas sales market appears to be its contractual right to gas from the Cooper Basin arising from the terms of the Letter of Agreement. However, the terms on which that gas is transported from Moomba to Wilton are set out in the Gas Transportation Deed. The Council considers that until 2006, while the Letter of Agreement and Gas Transportation

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3. AGL has the right from time to time to reduce the total remaining volume of gas for the term of the contract subject to certain restrictions and conditions (cl 19).

4. Clause 20, the exclusive dealing clause, prevents AGL from purchasing natural gas from any supplier other than the Producers except to the extent by which its requirements exceed the maximum amount which it is entitled to take and the Producers are able to supply under the Agreement.

5. Clause 24, the "price and price review" clause which provides as follows:

(a) Clause 24(a) establishes the price which AGL has to pay for the gas or make the take or pay payment.

(b) Clause 24(b) is the price review clause.

(c) Clause 24(c) contemplates that the parties may from time to time agree upon a formula to be applied in the then current or subsequent price adjustments either in lieu of or in addition to the formula mentioned in clause 24(a). Thus clause 24(c) does contemplate additions or modifications to the formula which is prescribed in clause 24(a).

(d) Clause 24(d) is the arbitration clause.

Deed remain in place, the owners of the MSP have no incentive arising from AGL's share of the beneficial ownership of the MSP to discriminate in favour of AGL in the relevant upstream gas sales market, as the terms on which AGL purchases gas and the terms on which that gas is transported from Moomba to Wilton are governed by the existing agreements. The Council has assumed that those agreements will remain in place in accordance with their terms, with or without coverage. That is, at least while those agreements remain on foot, the Council considers that the vertical linkages between the MSP and AGL are neutral as to whether coverage would promote competition in the upstream market. However, the Council concludes at paragraphs 7.196 and 7.315 to 7.405 that the MSP may have the ability and incentives to distort competition in the upstream market through monopoly pricing of transportation services.

7.590 The Council has not been provided with any information in relation to the terms on which AGLWG would acquire transport services from the MSP, if absent coverage the Gas Transportation Deed terminates.

7.591 After the Letter of Agreement has expired, AGL will have no contractual right to acquire natural gas from the Cooper Basin but the MSP will have a contractual obligation to AGLWG to supply, and AGLWG will have a contractual obligation to acquire the 162 Firm Service, being a reservation of an MDQ of 162 TJ/day which represents about 34% of the MSP's current installed capacity[144]. It may be that at that time, the MSP may have the incentive to offer more beneficial terms to AGL or its affiliates for transport than the terms offered by the MSP to third parties and it is required to do so under the Gas Transportation Deed (see paragraph 7.604). However, this incentive does not arise from any upstream interest held by AGL but arises from the downstream interest of AGL in AGLWG.

Assessment of likely effect of strategies on competition in downstream markets absent coverage

7.592 As set out above, the Council considers that the owners of the MSP may have an incentive to act in AGL’s interests (provided that in so

[144] The Gas Transportation Deed provides that EAPL will provide the Firm Transportation Service and supply that service on terms and conditions set out in Service Contract which the Council has not seen. The Council assumes that Service Contract governs the terms on which EAPL is obliged to supply, and AGLWG is obliged to acquire the 162 Firm Service.

doing it is also acting in the interests of the unit holders as a whole). This includes the interests of AGL's wholly owned subsidiaries, such as AGLWG.

7.593 The Council has therefore considered whether the MSP can act in a manner which advantages AGLWG in the downstream market. One such strategy may have been the Gas Transportation Deed, which is currently in place between EAPL and AGLWG. The Gas Transportation Deed remains on foot until 2017. The provisions of the Gas Transportation Deed do not provide for termination if coverage is revoked, however, a number of the key terms of the Gas Transportation Deed assume coverage and their operation and enforceability may be open to question if coverage is revoked. In addition, absent coverage, it would be open for the parties to terminate the Gas Transportation Deed by agreement and enter into a new arrangement which, absent coverage, would not require ACCC approval under the Code (but may require authorisation under Part VII of the TPA). The Council has assumed that the Gas Transportation Deed is likely to remain in place with or without coverage but recognises the possibility that it may cease to be operative.

7.594 The terms of the Gas Transportation Deed have been formulated and approved by the ACCC in accordance with the Code, which would not have occurred if the MSP was not covered. It appears from the ACCC's Statement of Reasons that the terms of the Gas Transportation Deed approved by the ACCC, were different terms from those lodged, the original terms containing what the ACCC considered to be particular price disincentives to third party access. The original lodged with the ACCC was nonetheless lodged in contemplation of an approval under the Code. The Council therefore considers that the current terms of the Gas Transportation Deed (other than price) are the terms which exist as a result of coverage and would continue if the MSP remains covered. For the purposes of criterion (a), the Council has considered:

(a) whether, without coverage, those terms would remain in place or whether they would fall away; and

(b) the effect of each of these scenarios on competition in downstream markets.

7.595 The Gas Transportation Deed sets the terms on which the MSP will provide transport services to AGLWG in two periods:

(a) until 2006; and

(b) from 2007 to 2016.

7.596 Until 2006, AGLWG is required to take or pay for a reserved pipeline capacity. That reserved capacity is not specified in the Gas Transportation Deed (which merely provides that in the period from 30 June 2000 until 1 January 2007, EAPL will provide Services to AGLWG on terms and conditions set out in the Service Contracts then in force between AGLWG and EAPL). **[confidential information]** (EAPL 2002, p.4).

7.597 The price which AGLWG pays for transport services is set by the Gas Transportation Deed. **[confidential information].**

7.598 **[confidential information]**

7.599 **[confidential information]**

7.600 **[confidential information]**

7.601 During the period until 2006, the Gas Transportation Deed also includes particular provisions relating to the supply of transport services by MSP to third parties. Those provisions include payment to AGLWG of a percentage of revenues received from third parties in certain circumstances. Until 31 December 2002, AGLWG is paid 50% of any payment received from a third party for transport of gas via the MSP above the "base amount". The "base amount" is the total revenue from third party sales earned by EAPL in 1999. **[confidential information]**. (EAPL 2002)

7.602 From 2007 to 2016, the reserved capacity for AGLWG is an MDQ of 162TJ delivered from Moomba to Wilton ("162 Firm Service"). This represents about 34% of the current installed capacity of the MSP of around 470TJ/day. The price which AGLWG pays for the 162 Firm Service is the lower of the Published Reference Tariff for Firm Transportation Services applicable from time to time or the lowest price negotiated by the MSP with a third party for Comparable Services to the same extent (in terms of volume, capacity, other charges and period). For all other Firm Transportation Services, the price is the price negotiated between AGLWG and the MSP.

7.603 In considering the effect of the Gas Transportation Deed on competition in downstream markets, the Council has considered:

(a) the effect of the provisions of that Gas Transportation Deed before and after December 2006, absent coverage; and

(b) the availability of natural gas to customers located in the relevant market (NSW/ACT or particular regional markets) from sources other than the Cooper Basin. Those sources include Gippsland Basin gas, transported via the EGP or the Interconnect.

7.604 EAPL and APT have submitted considerable confidential information in relation to the operation of the Gas Transportation Deed until 2006, to refute the Council's finding in the draft recommendation that EAPL has an incentive to sell transport to AGLWG.

7.605 The provisions of the Gas Transportation Deed do not appear to require EAPL to sell transport to AGLWG at a price which is lower than the price at which it provides transport services to third parties. However, these provisions do ensure that the price paid by AGLWG is the lowest price and thus create an incentive for the MSP to increase the price it charges third parties or reduce the incentive for the MSP to sell transport services to third parties. This results in an indirect preference for AGLWG, as the transportation by third parties of gas from Moomba to Sydney in competition with AGLWG is limited.

7.606 However, the terms of the Gas Transportation Deed require EAPL to reserve capacity for AGLWG, thus limiting the capacity available to potential third parties. **[confidential information]**. Further, in particular circumstances until 31 December 2002, AGLWG shares the benefit of third party transport through receiving a share of that revenue. While this may not result in preferential terms or pricing to AGLWG in terms of the actual tariff that it pays, the revenue sharing arrangement effectively means AGLWG receives an advantage from any transportation services provided by EAPL to third parties. This does not mean that such an advantage to AGLWG is contrary to the interests of the beneficial owners of the MSP - rather, as submitted by EAPL, it is in the interests of EAPL to sell transportation services to third parties and receive 50% of that revenue (AGLWG receiving the remaining 50%) rather than EAPL receiving no additional revenue.

7.607 As set out above, the Gas Transportation Deed assumes that there will be a published tariff set by the applicable regulator under the applicable third party access regime (absent any access arrangement, it assumes the Transporter will publish a tariff and access and tariff policy). It is therefore difficult for the Council to consider the effect of the Gas Transportation Deed on competition in downstream markets, absent coverage.

7.608 The Council notes that there is no right to terminate the Gas Transportation Deed in the event that the MSP is not subject to access regulation. Presumably, absent a reference tariff approved by the ACCC, the tariff for any service would be the lower of any published reference tariff and the lowest tariff which the transporter has negotiated with any other customer for a comparable service and the price for any other service would be the price negotiated between MSP and AGLWG. The Council notes in this regard that the ACCC's approval of the Gas Transportation Deed as an Associate Contract under the Code assumed a published regulated reference tariff.

7.609 The Council considers that currently, and until 2006, the effect of the Gas Transportation Deed is that the terms on which EAPL provides transportation services to AGLWG are more favourable than the terms upon which those services may be supplied to third parties due to the reserved capacity, the most favoured customer pricing provisions and, until 31 December 2002, the revenue sharing from third party sales.

7.610 In the period from 2007 to 2016, the Council considers that the effect of the Gas Transportation Deed is to guarantee to AGLWG:

(a) a minimum daily quantity which amounts to about 34% of the current daily capacity of the MSP; and

(b) that AGLWG will pay no more than the lowest tariff negotiated by a third party for transportation of natural gas via the MSP.

7.611 Absent coverage, the Council considers that this preference for AGLWG would continue, with the important difference that:

(a) third parties would have no right to negotiate access to the MSP; and

(b) there would be no published tariff to maintain a cap on the price for transport on the MSP.

7.612 The Council considers that, absent coverage, the provisions of the Gas Transportation Deed may give the MSP incentive to distort competition in downstream gas sales markets for the following reasons:

(a) it has a guaranteed customer for:

(i) [confidential information];

(ii) **[confidential information]** 34% from 2007-2016;

creating little incentive for the owners of the MSP to sell transport services to third parties, particularly until 2006; and

(b) without the discipline imposed by coverage on the tariffs charged for transport on the MSP, the MSP would have the ability to increase the price of transportation services without loss of its major customer.

7.613 The Council notes that third party downstream customers may have the option of acquiring natural gas from the Gippsland Basin, namely transportation via the EGP or via the Interconnect. The Council also notes the Tribunal in the *EGP decision* considered that there exists competition in downstream markets between alternative sources of gas supply.

7.614 However, the Council has found at paragraphs 7.313 to 7.314, following a discussion from paragraph 7.197, that relevant downstream gas sales markets are not effectively competitive at present, and are unlikely to become so in the short to medium term. While those markets appears to be more competitive than in the past, they are not sufficiently competitive to constrain MSP tariffs.

7.615 Currently, the Gas Transportation Deed is in terms approved by the ACCC, which approval assumes a minimum reference tariff regulated by the ACCC. Under the Code, third parties have a right to negotiate for the provision of transport services by the MSP. The MSP is also subject to the ringfencing obligations of the Code. The MSP has always been subject to a form of access regulation and the provisions of the Gas Transportation Deed assume access regulation. The tariffs set by the MSP for transport services are considerably higher than the ACCC draft indicative tariffs (adjusted). Absent coverage and assuming the Gas Transportation Deed remains on foot, the Council considers that the reservation of pipeline capacity in favour of AGLWG and the provision of transport services by the MSP to AGLWG on terms which are equal to the best terms negotiated by any other customer, together with the absence of a competitive tariff set by the ACCC, the absence of a statutory right of third parties to negotiate for the provision of transport services via the MSP and a right to those services on the basic terms and conditions set out in the Access Arrangement, is likely to distort competition in downstream markets.

7.616 Given that AGLWG currently ships **[confidential information]**of expected MSP deliveries, **[confidential information]**, there seems little risk of decreased demand for the MSP's services by its major customer if the MSP increased the price of transport, at least until 2006. Given the ownership interest of AGL in APT and AGLWG, it is also likely that there is little risk of the MSP losing AGLWG as a customer after the expiry of the Gas Transportation Deed (assuming the current ownership structure is maintained).

Conclusion on criterion (a)

7.617 The Council concludes that coverage of the MSP Mainline and Canberra Lateral:

(a) would promote competition in upstream and downstream markets as a consequence of the ability and incentive of the pipelines to charge monopoly prices for transport services.

(b) would promote competition in downstream markets as a consequence of the ability and incentive of the pipelines to distort competition in those markets through vertical leveraging.

7.618 The Council therefore finds that the MSP Mainline and Canberra Lateral satisfy criterion (a).

8 Criterion (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

The Council's approach to criterion (c)

8.1 The rationale for criterion (c) is that the National Gas Code should not be applied to pipelines where access or increased access may pose a legitimate risk to human health or safety.

Issues arising

8.2 The Council did not receive submissions arguing that it would be unsafe to provide access or increased access to the services of the MSP Mainline or the Canberra Lateral. This is consistent with the Council's experience in relation to a number of applications seeking revocation of coverage of pipelines, where safety concerns were not raised to support revocation.

8.3 The National Gas Code contemplates the provision of access to pipelines throughout Australia under Gas Access Acts in each State and Territory. The Council is not aware of any instance where safety concerns have been raised in relation to access or increased access to the services of pipelines. Nor is there any available evidence to suggest that safety is a particular concern in relation to the provision of access or increased access to the services of the two pipelines for which revocation is sought.

8.4 NSW, South Australia, Queensland, and the ACT have passed regulations dealing with the safe operation of gas pipelines. The Council is confident that these regulations deal appropriately with any safety issues arising from access to the two pipelines.

Conclusion

8.5 The Council concludes that access (or increased access) can be safely provided to the services of the MSP Mainline and the Canberra Lateral. The Council therefore finds that the MSP Mainline and the Canberra Lateral satisfy criterion (c).

9 Criterion (d)

that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest

The Council's approach to criterion (d)

9.1 In the *Duke EGP decision*, the Tribunal clarified the interpretation of criterion (d) as follows:

> *... criterion (d) does not constitute an additional positive requirement which can be used to call into question the result obtained by the application of pars (a), (b) and (c) of the [coverage] criteria. Criterion (d) accepts the results derived from the application of pars (a), (b) and (c), but enquires whether there are any other matters which lead to the conclusion that coverage would be contrary to the public interest.* (Duke EGP decision 2001, paragraph 145)

9.2 The Council adopts a broad view of the types of matters that may raise public interest considerations under criterion (d), including the overall costs of regulation, and any effects that regulated access might have on the environment, regional development, and equity.

9.3 Because criterion (d) is phrased in the negative, a recommendation to revoke coverage would require that the costs of regulated access outweigh the benefits of regulating natural monopoly services with substantial market power. The extent of these benefits depends on the likely effect of regulating natural monopoly services on competition in related markets; issues considered under criterion (a).

Costs of regulation

9.4 Ordover and Lehr draw attention to the fact that regulation has costs and inefficiencies (Ordover & Lehr 2001, p.24). The Council has consistently recognised this fact and in a number of previous coverage and revocation matters, has considered whether the costs of coverage outweigh the benefits (for example, NCC 2000a). In making its current assessment, the Council has taken into account both the direct and indirect costs of regulation under the National Gas Code.

9.5 Direct costs of regulation might include the costs of preparing access arrangements; while indirect costs might include reduced incentives to invest in pipeline infrastructure or reduced incentives to innovate or provide flexible services.

9.6 The indirect costs of regulation may be lower in the context of the National Gas Code than for more prescriptive access regimes. As recognised by Ordover and Lehr (at p.21), the pricing mechanisms within the National Gas Code lessen the standard concerns about inefficiencies that may result from regulatory pricing rigidities. This is because the National Gas Code does not restrict the ability of parties to negotiate away from regulated reference tariffs.

Issues raised in submissions

9.7 The following issues of relevance to criterion (d) were raised in submissions:

(a) covering the Moomba to Sydney Pipeline system (including the MSP Mainline and the Canberra Lateral) while the EGP is uncovered raises concerns of asymmetric regulation;

(b) the costs of regulation; and

(c) the costs and benefits of the National Gas Code's information disclosure provisions.

Asymmetric regulation?

9.8 A number of submissions discussed whether it was appropriate to regulate the MSP Mainline and the Canberra Lateral in view of the decision of the Tribunal that the EGP should not be covered under the National Gas Code. NECG, the AGA, EAPL, AusCID and Duke Energy argued it was inappropriate to regulate the MSP Mainline and the Canberra Lateral while the EGP (which supplies gas to some of the same geographic areas) is uncovered. Submissions from Incitec, Santos, BHP Billiton and the EMRF took a contrary view.

9.9 NECG considered that "if the [Moomba to Sydney Pipeline System] continues to be covered while the [Eastern Gas Pipeline] is not, this would constitute asymmetric regulation" (NECG 2001, sub.9, p. 34).

9.10 The AGA argued there was a public interest in not regulating the Moomba to Sydney pipeline system when another pipeline transported gas to Sydney and Canberra:

> *… there should be a strong regulatory presumption that where two pipelines serve the same market, regulatory frameworks*

should be similar. This symmetrical regulatory framework should apply both in the nature of the regulatory framework and whether it is applied to both pipelines.

Differences in the regulatory obligations and costs facing the operator of a covered pipeline competing with an uncovered pipeline could reduce competition in the gas transmission market, and the benefits to final consumers. The commercial operation of a pipeline covered under the Code competing with an uncovered pipeline would be extremely difficult and without any public benefit. (AGA 2001, sub.8, p.7).

9.11 Submissions to the Council raised a number of arguments related to perceptions of asymmetric regulation. The arguments relate to implications for:

(a) equity considerations;

(b) the commercial value of the Eastern Gas Pipeline;

(c) downstream competition; and

(d) incentives to invest in infrastructure generally.

Equity considerations

9.12 EAPL argues that:

as a general principle it is fundamentally unfair and contrary to the public interest for the [Moomba to Sydney pipeline system] to be covered when its principal competitor [the Eastern Gas Pipeline] is uncovered" (EAPL 2001, sub.6, p.16).

9.13 Similarly, the AGA argues that it is inappropriate to adopt different approaches to regulation in this instance on the grounds of fairness:

Where two pipelines serve the same market there should be a strong presumption that regulatory frameworks should be similar. This symmetrical regulatory treatment should apply both in the nature of the regulatory framework and the application (i.e. coverage) of the framework to both pipelines. This presumption should be made as a matter of fairness (AGA 2002, sub.17, p.16).

9.14 The AGA cites Ordover as stating that:

Regulatory policy needs to strive towards a level playing field that does not arbitrarily constrict the ability of any one firm to *respond to its rivals or to gain competitive advantages (Ordover 2000, p.31).*

Effects on the Eastern Gas Pipeline

9.15 Duke Energy argues that the ultimate effect of continued regulation of the MSP may be to substantially depreciate the capital base of the EGP:

> *In the situation where a new asset is in competition with a mature asset, the effect of regulating the terms and conditions upon which the owner of the mature asset trades will operate to set de facto regulated terms and conditions of trade for the new asset.*
>
> *This is the precise situation faced by the newly constructed EGP in competing with the mature MSP. In this case, (and assuming the reference tariffs derived by the ACCC in its Draft Decision of 2000 hold) the cost to DEI, as owner of the EGP, can be measured by the immediate potential decrease in the value of the EGP by many millions of dollars. While this would result in short-term reductions in reference tariffs, it is entirely at the expense of long term allocative and dynamic efficiency* (Duke Energy 2002, sub.21, p.12).

Effects on downstream competition

9.16 AusCID argues that asymmetric regulation between the Moomba to Sydney Pipeline System and the EGP may distort competition in the Sydney gas market:

> *.. if the NCC upholds its draft decision not to revoke coverage of the MSP... [c]onsumers will face a choice between two pipelines competing to provide them the same service, the delivery of gas, yet one will be regulated and forced to charge a regulator-determined tariff, while the other is free to set prices as it chooses.*
>
> *As these pipelines compete, the net effect of the decision is that the EGP will be forced to offer similar prices to the MSP's regulated prices. This is not the situation in which the Gas Code was designed to be used. The delivery of gas to the Sydney market is competitive, and it is in the public interest that the competitive tension between suppliers be used to determine prices, rather than regulated outcomes that distort the market, and are prone to error.*

Effects on investment incentives generally

9.17 The Productivity Commission's report on the National Access Regime (PC 2001, p.66), raised concerns that access regulation may have a potentially chilling effect on investment in essential facilitates. Similarly, the Hilmer Review noted:

> *...when considering the declaration of an access right to facilities, any assessments of the public interest would need to place special emphasis on the need to ensure that access rights did not undermine the viability of long-term investment decisions, and hence risk deterring future investment in important infrastructure projects.* (Hilmer 1993, p.251)

9.18 Duke Energy argues that asymmetric regulation may, in this case, adversely affect investment incentives generally, given that different standards of regulation would apply to a mature asset – the Moomba to Sydney Pipeline System – as compared with a newly constructed asset – the EGP:

> *If new infrastructure investments are forced to compete with existing infrastructure on the basis of the depreciated value of the existing infrastructure, then there will be little incentive to invest in new infrastructure. Without investment, there will be an ageing of the national infrastructure asset base, an erosion of international competitive business conditions, reduced opportunities for economic growth and reduced opportunities for employment and growth in national wealth* (Duke Energy 2002, sub.21, p.14).

9.19 AusCID makes a similar point, arguing that asymmetric regulation sends signals of randomness as to whether infrastructure will be regulated:

> *The draft decision [not to revoke coverage], if implemented, will create a situation of significant uncertainty for investors in regulated infrastructure, particularly gas pipelines. With the Eastern Gas Pipeline unregulated and the Moomba to Sydney Pipeline regulated, new investors in other pipelines will be forced to guess whether their new investment will be regulated, with the declaration decision taken after the investment in the pipeline is sunk.*
>
> *Investors in new pipeline assets will face an investment decision in which they cannot reasonably predict whether the new pipeline investment will be regulated or not. Considering the previous track record of ACCC determinations on access pricing, whether the pipeline is covered, particularly for marginal and risky*

investments, can be the difference between a project being successful and a project failing. This uncertainty imposes significant costs on investors in new regulated infrastructure (AusCID 2002, sub.22, p.4)

9.20 AusCID argues that in the longer term, uncertainty as to whether a pipeline is regulated will lead to reduced and/or delayed investment in gas pipelines, with adverse consequences for the community.

The Council's views on asymmetric regulation

9.21 The Council considers each application for coverage or revocation on its merits. Where pipelines possess similar characteristics, it is reasonable to expect that consistent application of the coverage criteria would result in the same coverage or revocation outcome in respect of each pipeline. However, where there are significant differences between pipelines, a consistent application of the coverage criteria might result in different coverage outcomes.

9.22 The Council considers that there are fundamental differences between the circumstances of the EGP, and the MSP Mainline and Canberra Lateral. As discussed under criterion (a), the Council has reached a view that EAPL is able to exercise substantial market power in providing the services of the MSP Mainline and the Canberra Lateral. This can be compared with the Tribunal's finding that Duke Energy does not have market power in providing the services of the EGP. These differences suggest there are valid grounds for coverage of the MSP Mainline and Canberra Lateral despite non-coverage of the EGP.

9.23 The Council does not consider it contrary to the public interest to regulate pipelines that are able to exercise substantial market power while not regulating pipelines without market power. This outcome is clearly the intention of the National Gas Code; as evidenced by the inclusion of coverage criteria that use the existence of market power as a major determinant.

9.24 The Council notes that perceptions of asymmetric regulation, as raised by a number of parties, appear to flow from an assumption that the Moomba to Sydney Pipeline System and the EGP compete against one another in a direct sense. As the Council explains in its discussion of criterion (a), competition between the pipelines, to the extent that it occurs, is derived from competition between bundled products of delivered gas. That the pipelines do not compete with one another in a direct sense is apparent from the fact that the tariffs charged by each pipeline for shipping gas to Sydney are substantially different; and the fact that these tariffs have become more divergent since 2000 (see discussion at paragraphs 7.204 to 7.205). Thus, it is difficult to sustain the argument that different approaches to regulation might require the EGP to match regulated Moomba to Sydney Pipeline System tariffs.

9.25 Regarding implications for the commercial value of the EGP, the Council notes that the EGP was financed and constructed in an environment in which the Moomba to Sydney Pipeline System was a covered pipeline. In this sense, it is reasonable to assume that parties invested in the EGP with full knowledge and expectation that the provisions of the National Gas Code would apply to the Moomba to Sydney Pipeline System.

9.26 The Council has also taken account of the potential costs of access regulation for investment generally. The Council notes that the principal issues raised in submissions relate to the perceptions of asymmetric regulation in this instance. The Council does not accept these arguments for the reasons outlined above.

9.27 Aside from perceptions of asymmetric regulation, the Council is not aware of any reasons why coverage in this instance raises unique issues of investment risk. The Council notes that the Moomba to Sydney Pipeline System is a mature pipeline that has been covered under the National Gas Code since the Code's inception, and was previously the subject of access legislation set out in the *Moomba to Sydney Pipeline System Sale Act 1994 (Cwlth).* Thus, issues of investor uncertainty that might reasonably be associated with greenfields pipeline investments do not arise here.

9.28 The Council further notes that in listing the Moomba to Sydney Pipeline System on Schedule A of the Code, Governments regarded the pipeline as having substantial market power, and therefore, as a pipeline that should be regulated. Governments implemented the National Gas Code to provide appropriate regulation of natural gas pipelines with substantial market power.

9.29 Based on the Council's assessment of criterion (a), the Moomba to Sydney Pipeline System continues to enjoy substantial market power that can be exploited in dependent markets. While regulation of any gas pipeline carries attendant costs, the Council found under criterion (a) that the competition benefits of coverage in this case are substantial.

Direct costs of regulation

9.30 The Council recognises that there are direct costs associated with regulation under the National Gas Code and that these can be significant. Costs include the pipeline owner's costs of preparing access arrangements and the regulator's costs of assessing compliance with the requirements of the Code. There is also the risk of regulator error, or the perception of it, given that regulated access pricing is a complex and contentious area.

9.31 The AGA argued that the "owners of gas transmission pipelines have consistently found the Code to be heavy-handed and extremely information-intensive" (AGA 2001, sub.8, p.6). It estimated that "since the introduction of the [National Gas] Code, the cost to operators of gas transmission pipelines of preparing Access Arrangements for approval by regulators has been over $13 million" (AGA 2001, sub.8, p.6).

9.32 The Council notes that some of the costs commonly associated with regulation may be incurred in any case; for example, settling terms and conditions of access with third party shippers. It is reasonable to assume that the costs of regulating monopoly infrastructure were taken into account by CoAG in its decision to implement the National Gas Code.

9.33 In addition, the costs of regulation need to be viewed in relation to the likely benefits of regulating access to a particular service. The benefits of regulating access flow from the restraint of monopoly pricing. Access regulation can make upstream and downstream industries more viable, reduce delivered gas prices to consumers and reduce the need for unnecessary investment in alternative facilities. Santos, for example, draws attention to the "public interest benefits of lower access prices and more efficient use of resources" (Santos 2001, sub.4, p.2).

9.34 Santos also argued that for pipelines like the MSP Mainline and the Canberra Lateral, which transport very large amounts of gas annually, even a small reduction in tariffs as a result of regulation is likely to outweigh the costs of regulation (Santos 2001, sub.4, p.2).

9.35 In this sense, the direct costs of access regulation are likely to be low compared to the potential cost reductions on the MSP Mainline and the Canberra Lateral. The MSP Mainline will transport in the vicinity of 90 – 100 PJ/a over the period 2001 – 2005, with volumes rising significantly after that (ACCC 2000b, p.95).[145] Thus, a tariff reduction of only 1¢/GJ on volumes of 100 PJ/a over the proposed five year period of the access arrangement for the MSP Mainline and the Canberra Lateral could generate total savings in the vicinity of $5 million.

9.36 If the regulatory costs across the period 2001-2005 were $2 – 3 million, then the associated benefit in reduced tariffs would only need to be 0.4 – 0.6¢/GJ, to offset the impact of the direct costs of regulation on delivered gas prices (assuming all of the regulatory costs were passed on). In comparison, adjusted indicative tariffs proposed by the ACCC over the period 2001 – 2005 are, on average 16¢/GJ less than EAPL's current tariffs (ACCC 2000b, p.119).[146]

9.37 The Council concluded under criterion (a) that the MSP Mainline and Canberra Lateral have substantial market power, as evidenced by:

(a) the lack of an effective competitive constraint in upstream and downstream markets; and

(b) the substantial gap between efficient prices and current tariffs charged by EAPL.

9.38 In the circumstances, the benefits of coverage for competition are likely to be significant. For large users in particular, the gains from regulation in the form of substantially reduced tariffs could be very significant. Against this, evidence on the direct costs of coverage suggests that these are relatively small compared to the likely benefits of coverage.

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145 EAPL has provided confidential information to the Council that 2002 MSP deliveries are expected to reach **[confidential information]** (EAPL 2002, p.4). This compares with published forecast of 89.8 PJ (ACCC 2000a, p.91), suggesting that **[confidential information].**

146 For the Moomba to Sydney transportation service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005, adjusted to reflect recent changes in the ACCC's approach to deferred tax liabilities ($0.50/GJ).

The comparison of the dead-weight costs of regulation with the likely reduction in transportation tariffs is used as an indication only of the likely relative magnitude of relevant costs and benefits.

9.39 The Council recognises that consideration of the costs of coverage is very important. Overall, the Council considers that the substantial benefits of coverage in this instance are likely to outweigh the costs.

Information Disclosure

9.40 If the MSP Mainline and Canberra Lateral were covered, then EAPL as the owner of the pipelines would need to comply with the information disclosure provisions of the National Gas Code. The Code requires owners of covered pipelines to provide information to users and prospective users on tariff determination methodology, capital costs, operations and maintenance costs, overheads and marketing costs, system capacity and volume assumptions, and key performance indicators (as set out in Attachment A to the Code).

9.41 In considering the current applications, a previous application for revocation of the MSP Mainline, and the application for coverage of the EGP, the Council received submissions on whether the information disclosure provisions in the Code confer a net benefit or cost. Some submissions have argued that the information disclosure provisions assist users by helping them to participate in the regulatory process of setting reference tariffs under the Code and in negotiating gas transportation contracts. Other submissions argued that the information disclosure provisions could facilitate parallel pricing strategies between the owners of the Moomba to Sydney Pipeline System and the EGP.

9.42 To find that criterion (d) is not met on the basis of the information disclosure provisions, the Council would need to be satisfied that:

(a) the information disclosure provisions represent a net cost (that is the dangers of parallel pricing outweigh the benefits of greater information disclosure); and

(b) these net costs (combined with any additional identified costs) outweigh the benefits of greater competition flowing from coverage as identified in criterion (a).

9.43 The Code's information disclosure provisions were designed to provide access seekers with information to aid negotiation of transportation contracts. Users and peak user bodies (the PIAC, Incitec, and the EUAA) have argued that the information disclosure provisions of the Code provide significant public benefits. For example, the Energy Users Association of Australia argue that:

> *Adequate information disclosure is not only crucial to the performance of regulators in access review but also to the involvement and participation of interested parties in the review process. … The history of pipeline access reviews conducted by regulators under the provisions of the National Gas Access Code to date indicates that input from third parties has been of considerable value.* (Energy Users Association of Australia, sub.7, p.4)

9.44 In considering coverage of the EGP, the Tribunal preferred the view that the Code's information disclosure requirements might facilitate parallel pricing between the Moomba to Sydney Pipeline System and the EGP (*Duke EGP decision 2001*, paragraph 115).

9.45 In the Duke EGP case, Mr Ergas, an expert economic witness called by Duke Energy, argued that information disclosure could facilitate parallel pricing by enabling the operators of the Moomba to Sydney Pipeline System and the EGP to know the intentions of the other operator with respect to "future capital expenditure and volumes (market share)" (*Duke EGP decision 2001*, paragraph 114). Dr Makholm, an expert economic witness appearing for the Council, contended that the information disclosure provisions would protect users against price discrimination (*Duke EGP decision 2001*, paragraph 114). The Tribunal considered that:

> *Dr Makholm's view that the information disclosure associated with coverage was beneficial was based on his view that [the Eastern Gas Pipeline] would engage in discrimination in favour of its associated marketer. As we have concluded that [the Eastern Gas Pipeline] is unlikely to be able to engage in such behaviour to the extent that it would interfere with the operation of a competitive market, it follows that any benefits from information disclosure would be small. This means that we come to the opposite conclusion to [the Council]: on balance, we prefer Mr Ergas' view.* (Duke EGP decision 2001, paragraph 115)

9.46 The Tribunal's finding was based on its earlier conclusion that Duke Energy would be unlikely to be able to engage in discrimination in favour of its associated marketer, Duke Energy Australia Trading and Marketing. On this issue, the Tribunal had stated:

> *… the Tribunal accepts that Duke [Energy] sees its commercial interests as being served by maximising throughput through the [Eastern Gas Pipeline], rather than in restricting it. It is always possible that circumstances could exist such that it might be in [Duke Energy's] overall commercial interests to practice discrimination in favour of its associated, or some other, marketer. However, it is unlikely that Duke [Energy] would be*

> *able to practice discrimination on any sustained basis, because of the Duke published prices, the competition between pipelines and high cross price elasticities between pipelines.* (Duke EGP decision, paragraph 112)

9.47 The Tribunal's conclusion that the dangers associated with the information disclosure provisions might, on balance, outweigh the benefits associated with greater transparency, are based on its view that Duke Energy's incentives are to maximise throughput and not to engage in price discrimination. In the *Duke EGP decision*, the Tribunal concluded that criterion (a) was not satisfied, meaning there were few or no identified benefits from greater competition to offset possible costs associated with information disclosure. Further, as the submission from EUAA points out, the National Gas Code provides the regulator with discretion to allow aggregation of information to protect a pipeline owners' or a user's legitimate business interests. This discretion can be exercised to prevent the flow of commercially sensitive information that could be used to engage in parallel pricing.

9.48 Further, the argument that the Code's disclosure requirements enhances the risk of parallel pricing fails to recognise that regulation constrains prices to cost-based levels. As such, the risk of parallel pricing is significantly reduced. Ordover and Lehr argue that:

> *By constraining prices, regulation sets a benchmark for unregulated prices that can be used by buyers in negotiations with the unregulated pipeline[s]. This could have a salutary effect on the overall prices. On the other hand, the requirement to price according to public tariffs tends to rigidify prices since the regulated firm cannot readily take advantage of a secret discount or surprise when deciding on a price reduction. Abstracting from the well-known costs and inefficiencies associated with regulation in general, we believe that coverage on balance would not facilitate collusion* (Ordover & Lehr 2001, p14).

9.49 The Council considers that the benefits of information disclosure in regard to the MSP Mainline and the Canberra Lateral – notably the promotion of a better-informed market – are likely to outweigh any costs associated with increased potential for parallel behaviour. This is because the benefits of information disclosure identified by users and user groups are significant, and because of the significant likely benefits associated with constraining MSP Mainline and Canberra Lateral tariffs.

Conclusion on criterion (d)

9.50 The Council concludes that access (or increased access) to the services of the MSP Mainline and the Canberra Lateral would not be contrary to the public interest.

9.51 The Council therefore finds that the MSP Mainline and the Canberra Lateral satisfy criterion (d).

Public submissions

First round of consultation

1. Australian Petroleum Production and Exploration Association, August 2001.
2. Public Interest Advocacy Centre, August 2001
3. Duke Energy International, August 2001.
4. Santos, August 2001.
5. GasAdvice (on behalf of nine major users), August 2001.
6. East Australian Pipeline Limited, August 2001.
7. Energy Users Association of Australia, August 2001.
8. Australian Gas Association, August 2001.
9. Network Economics Consulting Group (on behalf of EAPL), August 2001.
10. Incitec, August 2001.
11. Australian Pipeline Industry Association, August 2001.
12. Energy Markets Reform Forum, August 2001.
13. East Australian Pipeline Limited, September 2001.
14. Energy Markets Reform Forum, September 2001.
15. Australian Pipeline Trust, December 2001.

Second round of consultation

16. Energy Markets Reform Forum, January 2002.
17. Australian Gas Association, February 2002.
18. AGL, February 2002.
19. East Australian Pipeline Limited/Network Economics Consulting Group, February 2002.
20. Energy Users Association of Australia, February 2002.

21. Duke Energy International, February 2002.

22. Australian Council for Infrastructure Development, February 2002.

23. BHP Billiton Petroleum Pty Ltd and Incitec Ltd, February 2002.

24. BHP Billiton Petroleum Pty Ltd, March 2002.

25. East Australian Pipeline Limited, March 2002.

26. Duke Energy International, March 2002.

Third round of consultation

27. East Australian Pipeline Limited/Network Economics Consulting Group, September 2002.

28. AGL, September 2002.

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Attachments

Attachment 1: Australian Pipeline Trust – legal constraints on decision making

[confidential attachment]

Attachment 2: AGL linkages

Attachment 3: APL linkages

Attachment 4: Duke EGP decision: Relevance to the MSP applications

Attachment 5: Ordover and Lehr Report

Attachment 6: ACCC letter to the Council: Sept 13 2002

Attachment 7: ACCC advice on NECG submission

Attachment 8: NERA Report September 2002

Attachment 9: NERA Report October 2002

Attachment 10: Coverage criteria

Section 1.9 of the National Gas Access Code provides:

Subject to sections 1.4(a) and 1.10, the NCC must recommend that the Pipeline be Covered (either to the extent described, or to a greater or lesser extent than that described, in the application) if the NCC is satisfied of all of the following matters, and cannot recommend that the Pipeline be Covered, to any extent, if the NCC is not satisfied of one or more of the following matters:

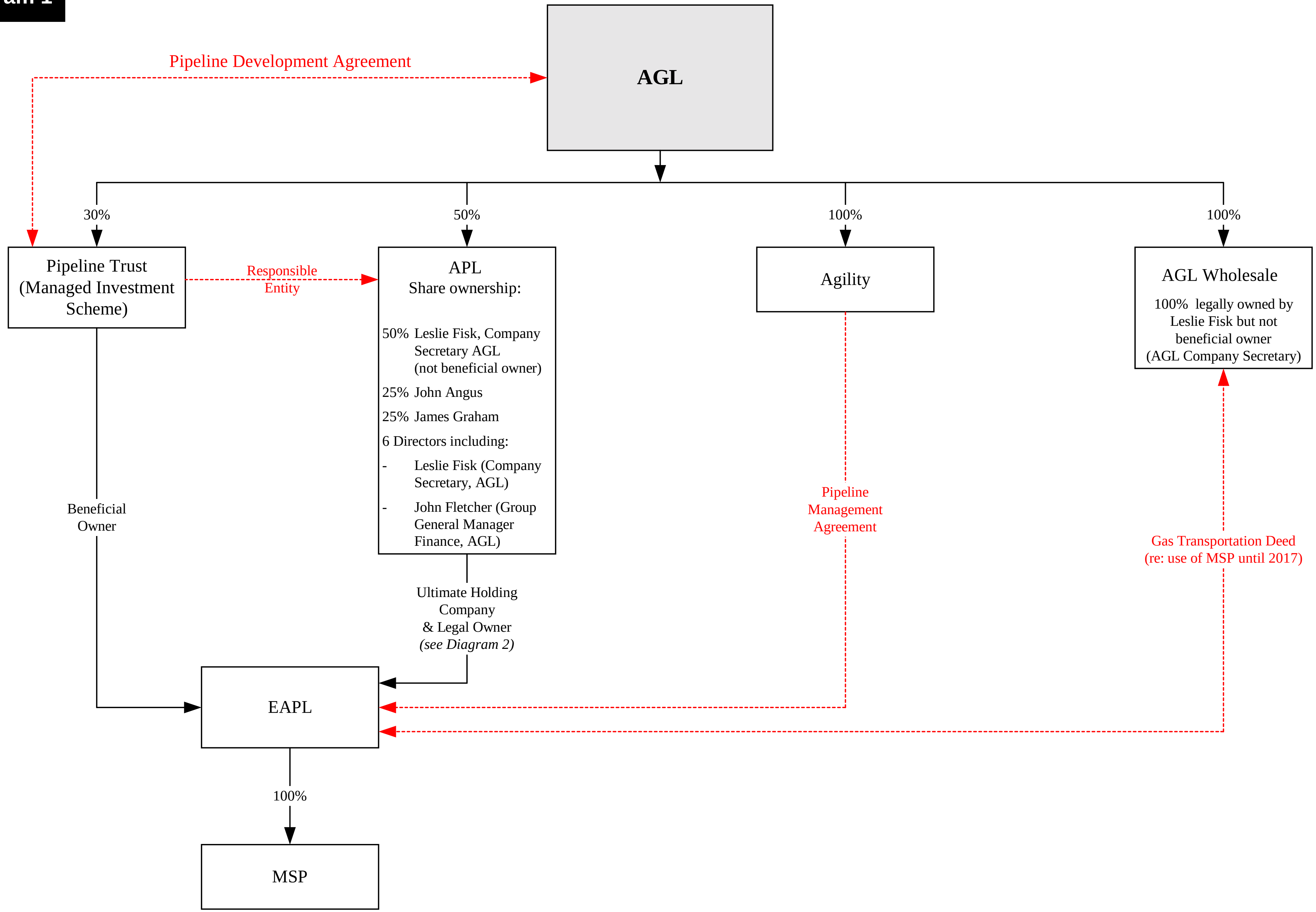
(a) that access (or increased access) to Services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline;

(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

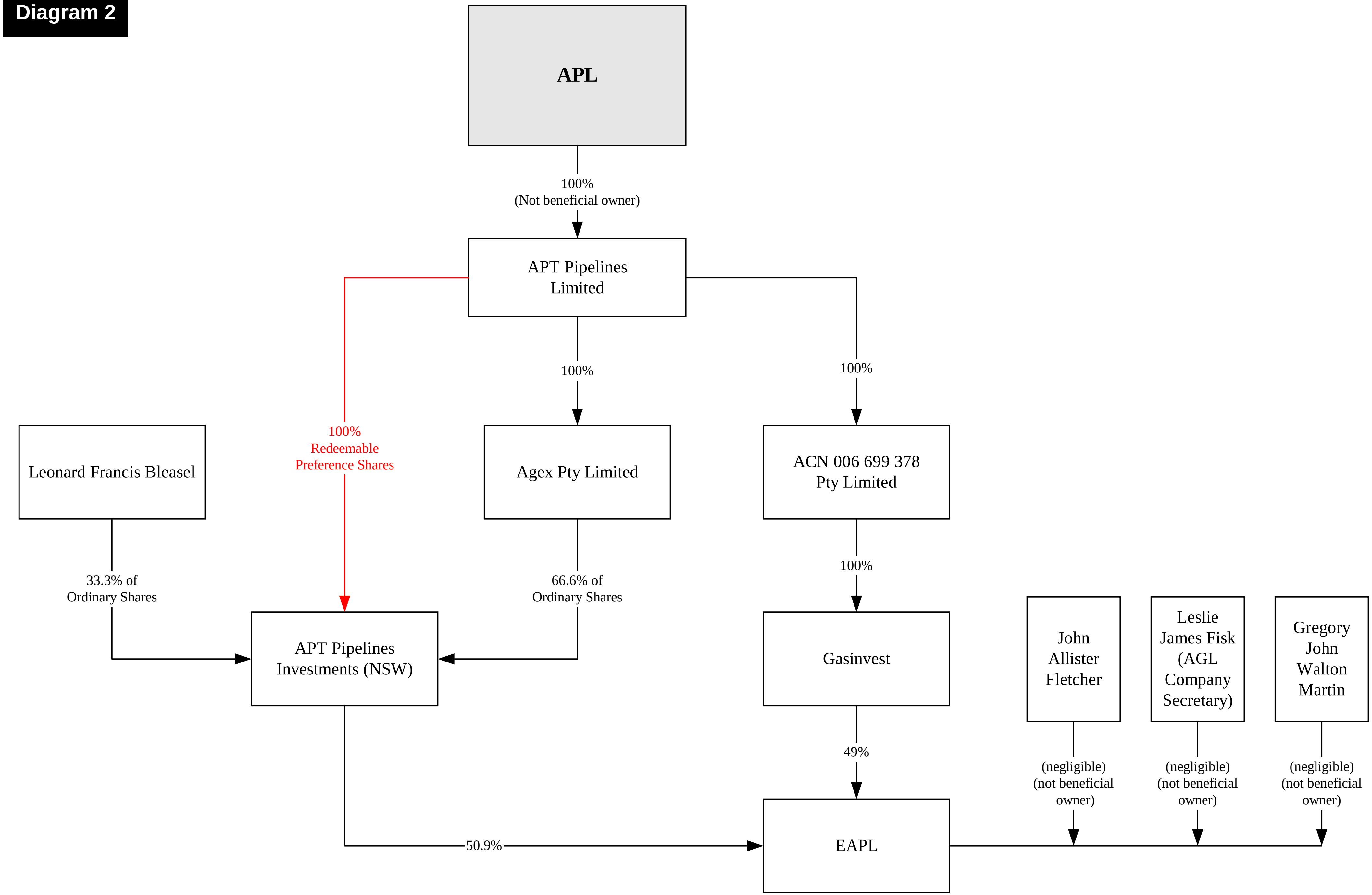
(d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

Diagram 1



2.12950.vsd

Diagram 2



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Duke EGP decision

The Tribunal found in the *Duke EGP decision* that the Eastern Gas Pipeline (EGP) had enhanced competition in downstream markets in NSW and produced the environment for interbasin competition (*Duke EGP decision 2001*, paragraph 81). The Tribunal noted, however, that while competition had improved since the opening of the EGP, criterion (a) turns on whether the opportunities and environment for competition in upstream/downstream markets would be enhanced if the EGP was covered (paragraph 83). The essential question is therefore whether coverage would improve the competitive environment compared to conditions absent coverage.

The Tribunal found that criterion (a) turns on whether the EGP has "power in the market for gas transmission which could be used to adversely affect competition in the upstream or downstream markets" (paragraph 116).

The Tribunal concluded that the EGP will not have sufficient market power to hinder competition in upstream or downstream markets, based on:

- the countervailing power of other market participants;
- the existence of spare pipeline capacity;
- the competition it faces from the MSP and the Interconnect; and
- the commercial imperatives faced by the pipeline (paragraphs 124, 134).

Below, the Council sets out the Tribunal's reasons. In addition, the Council comments on the circumstances of the EGP as compared with the MSP Mainline and Canberra Lateral (MSP[1]).

[1] The MSP Mainline and Canberra Lateral are separate pipelines for the purposes of this report, and the Council makes separate recommendations for each. For the sake of brevity, the abbreviation 'MSP' is used in parts of this report to jointly refer to the MSP Mainline and Canberra Lateral.

1 Countervailing power of other market participants

The Tribunal's findings

The Tribunal found that gas producers and gas buyers have significant power in dealing with pipeline operators: each has viable alternatives to the EGP, providing them with countervailing influence on attempts by the EGP to exert market power:

- the Gippsland Basin producers have two alternatives to the EGP: they can sell gas to NSW markets via the Interconnect (while the pipeline's northbound capacity is about 6.4 PJ/a, this can be expanded at low cost through backhaul arrangements to 23-24 PJ/a[2]); or they can sell gas to the Victorian market via the Victorian transmission network (*Duke EGP decision*, paragraphs 117, 122).

- downstream gas customers in NSW have two alternatives to the EGP: they can buy Victorian gas via the Interconnect; or Cooper Basin gas via the MSP (paragraph 118).

Comparison with MSP applications

Upstream

The Tribunal found that upstream producers in the Gippsland Basin have countervailing power over an attempted exertion of market power by the EGP, through their ability to divert sales to Sydney via the Interconnect, or into Victorian markets via the Victorian gas transmission network (paragraph 117).

The Council notes that the opening of the Tasmanian Gas Pipeline in 2002 provides a third potential sales alternative for the Gippsland Basin producers.

It has been suggested that the Cooper Basin producers can similarly constrain monopoly pricing on the MSP by diverting gas sales from NSW/ACT markets into Adelaide and Queensland markets. But:

- the Moomba to Adelaide pipeline (MAPS) is fully contracted. While capacity may become available from 2004-2005, demand forecasts indicate that the Adelaide market could not absorb the necessary diversions of gas sales to constrain MSP pricing.

- the Queensland scenario appears to be infeasible in the foreseeable future due to capacity constraints at Ballera and on the Roma to

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[2] Paragraph 122.

Brisbane pipeline, and due to other technical and commercial issues. While delivery of Cooper Basin gas into Queensland markets cannot be discounted as a possibility in the longer term, the Council has seen no evidence to suggest that the constraints outlined above will be resolved in the foreseeable future.

Therefore, the Cooper Basin producers do not have viable alternatives to constrain monopoly pricing on the MSP. The absence of viable alternatives enables the MSP to charge monopoly prices for shipping Cooper Basin gas.

Therefore, a significant difference from the circumstances of the EGP is the lack of scope for upstream competition to constrain the MSP.

Downstream

The supply alternatives open to downstream parties in Sydney differ in the present case from those identified by the Tribunal in the *Duke EGP decision*, in two regards.

First, a gas buyer wishing to ship gas from the Gippsland Basin to Sydney has two transportation options: via the EGP or via the Interconnect. However, there are no alternatives to the MSP for shipping gas from Moomba to Sydney. The distinction is significant to parties who require a delivery service from a particular basin (for example, a party may be able to secure a contract with a producer in one basin but not another). Hence, the options open to downstream customers are more limited with regard to the MSP than for the EGP.

Second, the Tribunal's *Duke EGP decision* was made against the context of the MSP being a covered pipeline. In this environment, the competitive constraint is likely to be relatively potent, as MSP tariffs would be regulated under the National Gas Code.

Whether countervailing power of market participants is sufficient to constrain a pipeline's market power depends on the effectiveness of the competitive constraint.

Evidence that the MSP's market power is not constrained in downstream (or upstream) markets is provided by pricing outcomes for the pipeline:

(a) The ACCC draft decision on the MSP access arrangement indicates that current MSP tariffs are about 32% above the tariffs allowable under the National Gas Code.[3] The Tribunal noted in the *DEI Queensland Pipeline decision* that the objectives listed at s.8.1 of the Code include "replicating the outcome of a competitive market," and affirmed that this involves prices that reflect efficient costs as well as non-price attributes tailored to

3 Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against ACCC indicative average tariff over the period 2001-2005, adjusted to reflect recent changes in the ACCC's approach to deferred tax liabilities ($0.50/GJ).

what customers want. The ACCC must take account of the s.8.1 objectives in determining appropriate reference tariffs under the Code.

(b) Modelling of MSP costs with regard to the investment actually made by the infrastructure owner (the 1994 purchase price, adjusted for subsequent investment) would result in current MSP tariffs being about 28% to 50% higher than tariffs derived from an initial capital base that reflects the 1994 purchase price.[4]

(c) An estimate by NERA of MSP tariffs that would apply under hypothetical new entrant pricing, found that current MSP tariffs are about 29% above contestable market prices.[5]

There is also a lack of evidence of customer switching in response to price movements. Further, the emergence of competition in the gas retail sector has been slow with only one retailer independent of the traditional incumbent now actively operating in Sydney; and none in the ACT.

Discussion in MSP Recommendation

paragraphs 7.132 to 7.196

2 Spare pipeline capacity and gas reserves

The Tribunal's findings

The Tribunal found that spare pipeline capacity will exist over the next 10-15 years, initially without the need to physically alter pipelines and later with relatively low cost capacity increases or capacity increases as a result of the use of gas to generate electricity. The Tribunal regarded the continued existence of spare capacity as one factor that militates against the EGP being able to exert market power in upstream/downstream markets.

The Tribunal found that if EGP prices rose above competitive levels, the spare capacity on other pipelines could be used to defeat the price rise, particularly in the first half of the decade when the MSP and the Interconnect could supply all of the forecast increase in NSW/ACT demand with increases in pipeline capacity at relatively low cost. There are also likely to be sufficient gas supplies from/through Moomba "to enable MSP to compete fully with EGP

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4 Based on valuation estimates in the ACCC draft decision on the MSP access arrangement: ACCC 2000b, p.41. The range reflects alternative assumptions about depreciation.

5 Moomba to Sydney service. Comparison of current tariff ($0.66/GJ) against NERA estimate of hypothetical new entrant pricing of $0.51/GJ.

for gas sales to the NSW/ACT market over the next 10 to 15 years" (*Duke EGP decision*, paragraphs 91, 99, 103, 118, 119).

Comparison with MSP applications

The implications of pipeline capacity on the MSP, EGP and Interconnect; and the availability of gas reserves in the Cooper and Gippsland Basins are relevant to the effectiveness of competition downstream of the EGP and MSP. Thus, the findings of the Tribunal are relevant to the MSP application.

However, there are at least two differences between the circumstances of the MSP and EGP applications. First, the Interconnect provides part of the same point to point service as the EGP (Longford to Sydney). The Tribunal has found that capacity on the Interconnect can be expanded at relatively low cost. Thus, downstream parties requiring delivery of gas from the Gippsland Basin to Sydney have a viable alternative to the EGP. Conversely, the MSP has a monopoly in the provision of services from the Cooper Basin to Sydney.

Second, as noted above, upstream producers in the Gippsland Basin can defeat monopoly pricing on the EGP by diverting gas sales to Sydney via the Interconnect, or to Victorian markets via the Victorian gas transmission network (or possibly, to Tasmania via the Tasmanian Gas Pipeline). However, as set out above, the Cooper Basin producers do not have viable alternatives to constrain MSP pricing by diverting gas sales into other markets.

Discussion in MSP Recommendation

paragraphs 7.123, 7.196, 7.207-7.217

3 Competition from other pipelines

The Tribunal's findings

In its discussion of elasticity of demand, the Tribunal referred to a cross-price elasticity of demand '2' between the EGP and the Interconnect, and said that this was supported by evidence about actual price sensitivity of gas purchasers in the market. The Tribunal cited Mr Henry Ergas as saying that if the EGP tariff was a monopoly price, there would be a greater risk that the analysis was incorrect but it would not be completely invalidated. The Tribunal was not convinced that this concern invalidated the analysis when taken together with the evidence of competition currently occurring and likely to occur. (*Duke EGP decision*, paragraphs 106-108)

The Tribunal noted the possibility that competition provided by the Interconnect and MSP may be insufficient to prevent the EGP from increasing prices and thus restricting output. The Tribunal did not believe that this possibility would occur. The Tribunal cited Mr Ergas' SSNIP analysis, suggesting that a relatively small price rise by the EGP could be defeated by the Interconnect because it could increase capacity at a cost below the current EGP tariff. The Tribunal also cited Mr Ergas' argument that the MSP could defeat a price increase on the EGP because of its uncommitted capacity and the adequate availability of gas (paragraph 120).

In support of its findings, the Tribunal cited evidence that the Interconnect could be expanded up to about 85 PJ/a (sufficient to transport much of the foreseeable demand for Gippsland Basin gas) at tariffs competitive with published EGP tariffs. The Tribunal considered that this supported the likelihood of price competition by the Interconnect (paragraph 121).

The Tribunal also found that about 23-24 PJ/a of northbound capacity on the Interconnect can potentially be developed using the existing infrastructure, through backhaul arrangements. In principle, this can be developed without any investment on the Interconnect. Development of the corresponding uncontracted capacity by EGP would require an investment in excess of $10 million. The Tribunal found that this "provides a significant argument against EGP being able to exert market power" (paragraph 122).

Comparison with MSP applications

The Council understands from discussions with Mr Ergas that the cross-price elasticity of demand estimate cited by the Tribunal was not the result of econometric modelling, due to the difficulty of obtaining data on normal, unfettered market behaviour. Mr Ergas has agreed that the SSNIP analysis could not be relied on to derive a precise estimate of the cross-price elasticity of demand.

In reference to the estimate cited by the Tribunal, Ordover and Lehr said:

> *We have seen the comments made in the Tribunal's decision in relation to the EGP on cross-price elasticities and the evidence of Mr. Ergas from which it appears that comment is derived. In our opinion, the material does not provide a sufficiently reliable empirical basis upon which to determine quantitative magnitudes of the pertinent cross-price elasticities.* (Ordover and Lehr 2001, p.20, footnote 39)

The estimate cited by the Tribunal referred to the cross-price elasticity of demand between the EGP and the Interconnect. Even if the estimate was accurate with regard to substitution between the EGP and Interconnect, there is no basis for assuming that the same estimate would apply to the cross-price elasticity of demand between the MSP and the EGP, given that the MSP and EGP provide different services.

There are similarities between the services of the EGP and the Interconnect that do not extend to the MSP. Both the Interconnect and EGP provide a service between Longford and Sydney (and between various locations along their respective routes).[6] Thus, a customer may be able to switch between the EGP and Interconnect without also having to switch between gas producers. Given that the MSP provides a different service to the EGP, the cross-price elasticity of demand between the MSP and the EGP is likely to be lower than between the EGP and Interconnect.

The SSNIP analysis that a relatively small price rise by the EGP could be defeated by the Interconnect raises questions as to why the EGP found it profitable to increase tariffs in 2002; ie EGP and Interconnect tariffs are diverging. Further, the price increase suggests that the EGP did not regard the MSP as a constraint on its ability to raise prices at current MSP price levels.[7]

The Tribunal focused at length on the ability of the Interconnect to constrain EGP pricing. This constraint does not apply to the MSP, given that the Interconnect does not provide a gas transportation service between Moomba and Sydney. Indeed, the MSP is the only pipeline that provides this service. Thus, "a significant argument against EGP being able to exert market power" does not apply to the MSP.

Whether the price of delivered gas from Gippsland constrains the price of delivered gas from the Cooper Basin in downstream NSW/ACT gas sales markets depends crucially on whether those markets are effectively competitive. Ordover and Lehr considered that it is premature to reach a conclusion of effective competition. In particular, they noted a lack of reliable evidence on the cross-price elasticity of demand for services from different pipelines or evidence that consumers are actively moving demand among sources of gas supply in response to fluctuations in prices.

As noted above, MSP pricing outcomes provide evidence that competition in dependent markets is not effective in constraining monopoly pricing on the MSP.

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6 When the Council refers to the Interconnect as providing a service between Longford and Sydney, it is using shorthand to describe a service provided by a combination of pipelines between Longford and Sydney, incorporating: the Victorian principal gas transmission network, the Interconnect, the Culcairn to Young lateral and the MSP Mainline.

7 The *Duke EGP decision* was made against the context of the MSP being a covered pipeline.

The Council notes the possibility that the EGP could raise its tariffs without raising the price of delivered Gippsland Basin gas in Sydney, if Gippsland Basin gas prices were falling. However, there is no evidence that EGP tariffs are rising for this reason. Annual price rises for EGP services are predetermined in the EGP's firm forward haulage service contract terms sheet (Duke Energy 2001b). It is likely, therefore, that annual escalations in EGP tariffs are weakening whatever discipline the EGP may previously have applied to MSP tariffs.

Discussion in MSP Recommendation

paragraphs 7.245-7.276, 7.302-7.314

4 Commercial imperatives faced by the pipeline

The Tribunal's findings

The Tribunal found that the EGP faces strong commercial imperatives to increase throughput, given its high capital cost, low operating costs, and spare capacity (paragraph 117).

Comparison with MSP applications

The MSP, as a natural gas transmission pipeline, is likely to exhibit broadly similar cost characteristics to the EGP: ie, high capital cost, low operating costs. The MSP also has substantial spare capacity. These factors, in themselves, are likely to create incentives for high rates of throughput.

A difference between the MSP and EGP is that the MSP is an established pipeline with a major contracted customer, AGLWG. Currently, gas delivered by the MSP for AGLWG represents a significant proportion of total gas deliveries in NSW. In comparison, the EGP is a new pipeline, with strong commercial imperatives to develop a market for its services.

Ordover and Lehr point out that while the cost characteristics of gas pipelines may create incentives for high rates of throughput, there is a risk of monopoly pricing and associated restrictions in output if the pipeline has substantial market power. According to Ordover and Lehr, the critical determinant of whether monopoly pricing will be profitable to the MSP is whether there is effective competition in dependent markets to constrain such behaviour.

Discussion in MSP Recommendation

paragraphs 7.120 – 7.127

5 Regional markets

The Tribunal's findings

The Tribunal noted that there are several places along the route of the EGP for which the EGP is the only source of gas. The EGP has created a gas sales market, and increased competition in energy supply, in places which were not previously served by a pipeline. The EGP also has the potential to increase competition in the gas production market if the Kipper field proceeds. However, criterion (a) must assess whether coverage would promote competition to a greater extent than has already occurred.

The Tribunal found that Duke's standard terms and conditions make monopoly pricing unlikely, because:

- EGP tariffs are published;
- EGP tariffs are non-discriminatory, potentially ensuring that any benefits due to competition between pipelines in Sydney and Canberra flow through to regional markets.
- regions along the route of the EGP are new markets that the EGP is attempting to develop by attracting consumers from other energy sources such as electricity. EGP prices will need to be constrained for gas market development to be successful.
- the threat of regulation remains open if prices are increased.

Given these factors, the Tribunal was not satisfied that coverage would promote competition in regional markets (*Duke EGP decision*, paragraphs 125-133).

Comparison with MSP applications

There are some similarities between the MSP and the EGP with regard to regional markets. In each case, the pipeline currently publishes tariffs and has a stated policy of non-discriminatory pricing, including distance-based pricing that would allow Sydney price reductions to flow through to regional markets.

However, the circumstances for regional markets along the route of the MSP differ from those served by the EGP. In particular, regional markets served by the EGP were not previously served by *any* pipeline.

In contrast, regional markets along the route of the MSP are established markets that have been served by the pipeline for over 20 years. Hence, the MSP would not face the same commercial imperatives to develop new gas markets through efficient tariffs as may be faced by the EGP.

Ordover and Lehr consider the case for coverage to be especially strong with respect to regional downstream markets:

> *... some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from coverage if it leads to lower transport prices and assured access to the pipeline* (Ordover and Lehr 2001, p.18).

Discussion in MSP Recommendation

paragraphs 7.293- 7.301, 7.309

6 Vertical linkages

The Tribunal's findings

Before reaching its conclusion on criterion (a), the Tribunal considered relationships between the EGP and Duke Energy Australia Trading and Marketing Pty Ltd (**DEATM**). Both DEATM and the operator of the EGP – Duke Australia Operations Pty Ltd – are wholly owned subsidiaries of Duke Energy Australian Holdings Pty Ltd (*Duke EGP decision*, 27-37).

DEATM is a wholesaler and aggregator of energy services. When it commenced operation in 1998, DEATM was the first new wholesale aggregator to offer bundled gas supply and transport services to the new retailers of gas in the Sydney region. It signed contracts with Citipower, Energy Australia and Integral Energy. Its only competitor in the supply of bundled services to retailers is AGLWG.

The Tribunal accepted that DEATM's commercial strategy is "to develop a diversified portfolio by obtaining gas from multiple sources and delivering it via multiple transportation routes".

The Tribunal cited evidence from a number of witnesses that there is no agreement, arrangement or understanding between Duke Operations and DEATM to favour DEATM in relation to the securing of contracts for transportation of gas to the EGP.

The Tribunal found that Duke is unlikely to discriminate in favour of DEATM because its commercial interests are best served by maximising throughput on the EGP. It is also unlikely that Duke could practise discrimination on a sustained basis, because of the Duke published prices, "competition between pipelines" and "high cross-price elasticities between pipelines." Whilst discrimination could occur, the Tribunal was not satisfied that it would have a material impact on competition. (112)

Comparison with MSP applications

The Tribunal noted that DEATM had entered into contracts with the Gippsland Basin producers for gas transported via the Interconnect, with the Gippsland Basin producers for gas transported via the EGP and with the MSP for Cooper Basin gas transported via the MSP (*Duke EGP decision*, paragraph 31). By contrast, AGLWG has a long term contact (the Gas Transportation Deed) with the MSP to transport gas from Moomba to Sydney, which remains in place until 2016. As far as the Council is aware, AGLWG does not have in place any contracts with the Gippsland Basin producers or with the EGP or Interconnect. AGLWG has not provided any details of any such contracts to the Council.

Thus, while DEATM's commercial strategy is "to develop a diversified portfolio by obtaining gas from multiple sources and delivering it via multiple transportation routes", there is no evidence to suggest that AGL has similar objectives.

In addition, the Council notes that while a significant proportion of MSP capacity is contracted to AGLWG, especially until 2006, the EGP does not have contractual arrangements of this magnitude with DEATM.

The Council considers that there is a very close relationship between AGL and APT/APL/EAPL. The Council considers that the extent of AGL's ownership of and relationship with APT/APL/EAPL creates an incentive for APL to act in AGL's interests. The Council notes legal restrictions on the MSP requiring conduct to be in the best interests of members of APT, but considers that those legal restrictions are unlikely, in many circumstances, to provide a constraint on the MSP acting in a manner to advantage an affiliate and so distort competition.

The Tribunal acknowledged the risk of Duke practising price discrimination in favour of DEATM, but considered this unlikely because of factors including "competition between pipelines" and the "high cross price elasticities between pipelines." The Council notes that these contexts differ with respect to the MSP. As the Council has noted:

- while the Interconnect provides part of the same point to point service as the EGP, the MSP is the only pipeline providing a service from Moomba to Sydney.

- there is no empirical evidence on the cross-price elasticity of demand between the MSP and other pipelines.

Discussion in MSP Recommendation

paragraphs 7.561-7.616

Should Coverage of the Moomba-Sydney Pipeline be Revoked?

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November 22, 2001

I. Introduction

The National Competition Commission (NCC) is considering whether to revoke coverage of the Moomba-Sydney Pipeline (MSP) under the Gas Act.[1] The MSP is the only pipeline system currently delivering gas from the Cooper Basin production fields to markets in New South Wales (NSW) and the Australian Capital Territory (ACT) in south east Australia. The MSP is owned by the East Australian Pipeline Limited (EAPL), which is the trustee of the Australian Pipeline Trust. The Australian Gas Light Company (AGL) owns 30% of the Australian Pipeline Trust and is a major gas retailer in ACT and NSW and its subsidiary, Agility Management Pty Limited is the physical operator of the pipeline.

Prior to 1998, the MSP accounted for almost all of the natural gas delivered into the NSW and the ACT retail markets.[2] Because of the lack of alternative sources of natural gas transport to the retail markets in southeast Australia, the MSP was subject to coverage under the Gas Act provisions which impose third party access requirements. However, no access arrangements for the MSP are currently in place under the Gas Act provisions.

In 1998, the previous owners of the MSP and the owners of a spur from the Victorian pipeline system jointly constructed the Interconnect pipeline to link the Victorian pipeline system to the MSP, thereby introducing another source of natural gas

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[1] Coverage of a pipeline under the *National Third Party Access Code for Natural Gas Pipeline Systems* imposes a regulatory regime that requires the pipeline operator to submit to the Australian Competition and Consumer Commission (ACCC) an arrangement for third party access, imposes disclosure requirements upon the pipeline operator, and puts in place an access dispute arbitration process. Hereafter, we refer to the Code and the other relevant legislation such as the *Gas Pipelines Access Law* and the *Natural Gas Pipelines Access Agreement 1997* collectively as the "Gas Act."

[2] In 1997, 95% of the natural gas consumed in NSW as supplied via the MSP (see page 27 of *Final Recommendation: Application for Coverage of the Eastern Gas Pipeline (Longford to Sydney)*, National Competition Council, June 2000).

transport into NSW and the ACT. In 2000, the Eastern Gas Pipeline (EGP) began operation, providing a source of natural gas transport from the major production fields in the Gippsland Basin to the retail markets in NSW/ACT. The EGP is owned by Duke Eastern Gas Pipeline Pty Limited and DEI Eastern Gas Pipeline Pty Limited and is operated by Duke Australia Operations Pty Limited (collectively Duke).

In January 2000, AGL Energy Sales & Marketing Limited, a related body corporate of AGL, petitioned the National Competition Commission (NCC) to subject the EGP to access coverage.[3] On 3 July 2000, the NCC made a recommendation to the Minister for Industry, Science and Resources (Minister) that the EGP should be covered and in October 2000 the Minister determined that the EGP should be covered.[4] Duke appealed the decision to the Australian Competition Tribunal (Tribunal) which revoked coverage in May 2001.[5] This prompted EAPL to apply to the NCC to revoke coverage of the MSP, which initiated the current proceeding. Meanwhile, in December 2000, the ACCC issued a draft order for access regulation of the MSP that calls for prices that are approximately 40% below current MSP rates.[6] This draft order is in abeyance until the current revocation proceeding is concluded.

The purpose of this memorandum is to provide advice to the NCC with respect to two important questions:

- First, given that the MSP presently is a natural monopoly in the provision of transportation services between Moomba and Sydney, what are the relevant economic criteria that should be used to determine whether that pipeline possesses market power in the provision of transmission services, and if it does, whether the pipeline has both the incentive and ability to exercise that power in the downstream market for gas sales?

- Second, based on the economic framework described above and a review of circumstances pertaining to the relevant markets in Australia, does the MSP possess substantial market power in the retail markets for gas sales in the NSW/ACT?

[3] For a pipeline to be subject to access coverage the Minister must be satisfied that each of the four criteria set forth in Section 1.9 of the *National Third Party Access Code for Natural Gas Pipeline Systems* are satisfied. The relevant criteria are cited in Section II below of this memorandum.

[4] See *Decision on Coverage of Parts of the Moomba to Sydney Pipeline System by Minister Nick Minchin*, 16 October 2000.

[5] See *Duke Eastern Gas Pipeline Pty Ltd* [2001] ATPR 41-821.

[6] EAPL proposed $0.708/GJ while the ACCC proposed $0.43/GJ. See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, Australian Competition and Consumer Commission (ACCC), December 19, 2000.

II. Criteria for Coverage Under the Gas Act: An Economic Assessment

A. Criteria for Coverage Under the Gas Act

To justify coverage of a pipeline under the Gas Act, it is necessary to show that all of the following four conditions are met:[7]

> "(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."

The advice which has been sought from us is relevant to the first and second criteria. We have not been asked to address any matters affecting criteria (c) and (d), and therefore, the balance of our comments will focus solely on the first two criteria. As will be clear shortly, it is easier if we address the first two criteria in reverse order.

B. Economic Assessment of Criterion (b)

Economic assessment of criterion (b) hinges on the meaning of the term "uneconomic" and the phrase "the services provided by means of the pipeline." Regarding the first term, there are three possible interpretations. The first interpretation relies on the concept of minimum viable scale. Minimum viable scale is the scale of operations that the entrant must attain in order to recover all of its forward-looking costs, given the current rates charged by the incumbent.[8] Under this interpretation, entry is "uneconomic" if the entrant is not able to recover all of its forward-looking costs for any level of output that it can conceivably capture, given that it is constrained to charge no more than the incumbent. Put another way, entry is uneconomic if the minimum viable scale exceeds the amount of business that the entrant can expect post-entry. It is possible that current rates are sufficiently above economic costs for entry to be profitable and yet such entry may be inefficient (higher cost).

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[7] See Section 1.9 of the *National Third Party Access Code for Natural Gas Pipeline Systems*.

[8] See, for example, Section 3, United States Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Revised 1997.

More generally, the entrant likely anticipates the impact of entry on post-entry competition and thus expects that current rates will fall. Under this second interpretation, entry is uneconomic if it is unprofitable for the entrant after taking account of the expected intensification of post-entry competition. Evaluating whether entry is "uneconomic" in this context depends in part on ones (or the rational entrant's) expectations about how competitive the market will prove to be after entry, which leaves the outcome ambiguous.

The third interpretation which seems most appropriate in the present situation is to focus solely on the costs of serving a given volume of demand. From this perspective, criterion (b) is satisfied if it would be economically inefficient for two or more pipelines to provide the volume of services offered by the pipeline under consideration. Thus, criterion (b) is satisfied if the total cost of serving a given level of output is lower if the output (in this case, gas transport services) is provided by a single pipeline rather than by two or more pipelines.[9] If this is the case, then the incumbent pipeline is a natural monopoly and competition between two or more pipelines offering the same services would be inefficient.[10]

Two remarks regarding this last interpretation of the "uneconomic" criterion are proper. First, whether entry is inefficient from a cost perspective depends on the target level of output. Thus, if demand for the service were to double from the current level, for example, there might be no cost penalty for having more than one firm providing the relevant service. Second, just because the provision of the service is a "natural monopoly," it does not mean that the incumbent is necessarily sustainable against a competitive incursion by a new firm. Consequently, profitable entry can occur into a monopolistic market, even if such entry would raise the total costs of production, as we note later.

Interpreting the second part of criterion (b) is much easier. The services provided by the MSP are the transport of natural gas from the production fields in the Cooper Basin to the retail markets in NSW and the ACT. In the short term, when the capacity is fixed, these services include the transport of any volume of gas from zero up to the capacity of the pipeline. Over the longer-term, when it is possible to expand capacity by adding additional compressor stations, the services may include the transport of gas in any volume up to the pipeline's maximum potential capacity. For another pipeline to

[9] Formally, a provision of a particular product or service is a natural monopoly if, over the entire relevant range of outputs, the firms' cost function is *subadditive*. A cost function C(q) is subadditive at q if it is always cheaper to produce a vector of outputs, q, in a single firm then by partitioning the output among two or more firms. For further discussion of these technical characteristics, see Sharkey, William, The Theory of Natural Monopoly, Cambridge University Press: Cambridge, (1982) and W J Baumol, J C Panzar, and R D Willig, Contestable Markets and the Theory of Industry Structure, HBJ Publishers: New York (1982).

[10] This interpretation of criterion (b) seems to be the one adopted by the Tribunal in the EGP decision at paragraphs 64 and 137 (see *Duke Eastern Gas Pipeline*, note 5, *supra*). The Tribunal stated at paragraph 137, "The test is whether for a likely range of reasonably foreseeable demand for the services provided by means of the pipeline, it would be more efficient, in terms of costs and benefits to the community as a whole, for one pipeline to provide those services rather than more than one."

provide the services offered by the MSP, it would have to transport natural gas between the Cooper Basin fields and the NSW/ACT markets.

Therefore, evaluating criterion (b) amounts to a determination of whether the MSP is a natural monopoly, which turns on the characteristics of the cost function associated with meeting any level of demand up to either the maximum potential capacity of the MSP or the maximum demand that the MSP pipeline might be called upon to serve, whichever is smaller. Note that this approach does not address the question of industry structure or market power, which are logically separate issues. For the determination whether the MSP is a natural monopoly in the provision of the transportation service between Moomba and Sydney (or any points in between), it is irrelevant that there are other pipelines between other sources of gas production and the retail markets in NSW and the ACT.

Indeed, as already noted, even natural monopoly does not assure that all of the demand is served by a single firm. Not all natural monopolies are sustainable against cream-skimming entry (*i.e.*, entry that seeks to serve only a portion of the market). For a particular combination of costs and market demand, entry on a scale smaller than the size of the market may be profitable, even though the cost of meeting total demand when it is supplied by multiple firms is higher.[11] Such inefficient entry is more likely the more restricted (by regulation, for example) is the incumbent firm in its ability to respond to market incursions and the more its prices deviate from economically efficient levels (due to cross-subsidies, for example).

The costs of constructing and operating a pipeline are largely sunk and fixed. Variable operating costs constitute a relatively small share of the total costs. For this reason, it seems plausible to expect that constructing and operating two (or more) point-to-point pipelines, each carrying only a share of the gas currently carried by the MSP would be "uneconomic", as we interpret criterion (b). Therefore, given the current and anticipated state of demand, it is reasonable to conclude, on cost criteria alone, that the MSP is a natural monopolist in the provision of transportation services for natural gas between Moomba and Sydney. Furthermore, we do not think that the threat of cream-skimming entry is likely given the costs of building a competing pipeline to run from Moomba to Sydney and the potential for expanding the existing MSP pipeline at relatively low incremental cost.

The conclusion that criterion (b) is satisfied is bolstered by consideration of the relationship between forecasted demand, production reserves in the Cooper Basin, and

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[11] If the cost function is supportable (*i.e.*, there exists a price, p, such that p*q = C(q) but for any other q' that is smaller than q, the product p*q' is less than or equal to C(q), where C(q) is the cost of producing the output vector q), then small scale entry against a natural monopoly whose costs are subadditive for all levels of output up to its capacity cannot occur. In a single product case, global economies of scale are sufficient to assure supportability and subadditivity are both satisfied and that the natural monopoly producing q is sustainable (see Sharkey, note 9, *supra*, pages 84-94).

the potential capacity of the pipeline (see Exhibit 1).[12] Taken together, these data indicate that the MSP is likely to be able to meet the relevant retail demand in NSW and the ACT retail markets and that the Cooper Basin reserves are not so large as to warrant construction of a second pipeline during the expected remaining lifetime of the MSP.[13] To the extent that the MSP has excess capacity today or is likely to have excess capacity in the future, the costs of serving the forecasted gas demand by two or more pipelines would be even higher.

Criterion (b) is a necessary (but not a sufficient) condition to justify coverage. When this condition is met, the total cost of transporting gas is minimized (and the goal of economic efficiency is served) when the activity is undertaken by one firm rather than by two or more firms. In the instant case, firms demanding transportation of natural gas between the production fields in Cooper Basin and the retail markets in NSW/ACT could not efficiently develop another pipeline that could compete with MSP without the overall cost of gas transport increasing. Such wasteful duplication of assets would engender inefficiencies to the detriment of the consuming public. Therefore, when criterion (b) is satisfied, it is efficient for firms wishing to ship gas between Cooper Basin and the NSW/ACT retail markets to avail themselves of the services provided by the MSP rather than constructing another pipeline. Coverage, if mandated, assures third parties access to the MSP.

Whether mandating coverage is desirable from the perspective of promoting competition in either the upstream or downstream market hinges on the evaluation of criterion (a), and is not a direct concern in the determination of whether criterion (b) is satisfied. The finding that criterion (b) is satisfied and that the MSP is likely to be a sustainable natural monopoly, has implications for the assessment of coverage under criterion (a). First, it eliminates consideration that entry by another pipeline between Moomba-Sydney will offer effective competition to the MSP for pipeline services. Second, the finding of natural monopoly leads to the presumption that the MSP may be able to convert its technological and incumbency advantage (deriving from the characteristics of pipeline costs) into significant market power in either the upstream or downstream market. Before considering criterion (a), however, we will explain the concept of market power and its relationship to the promotion of competition.

[12] We note that there are several potential projects referred to by the Tribunal in the EGP decision which involve the delivery of gas to Australia from offshore sources namely the Timor Sea and Papua New Guinea. Some proposals for the development of these offshore gas sources contemplate using Moomba as a hub for delivery on to Sydney. For example, the proposal for the Timor Sea gas involves an undersea pipeline to Darwin, construction of a pipeline from Darwin to Moomba, and then utilization of the Moomba to Sydney pipeline for delivery to the NSW/ACT markets. Based on the material we have reviewed, none of these proposals is sufficiently advanced to be taken into account under criterion (b).

[13] As Exhibit 1 makes clear, there is ample room to expand the capacity of the EGP and MSP such that they could separately or together address the growth in demand for natural gas in the NSW/ACT markets. Moreover, each has sufficient additional reserves in the associated upstream market so that either or both could expand its transport services above current levels either to respond to a shift in current market demand (perhaps in response to an attempt by one or the other pipeline seeking to raise prices above competitive levels) or to accommodate additional demand in the downstream retail markets.

C. Market Power

In economics, market power is defined as the ability to profitably raise prices above marginal cost. Any firm – other than a firm operating in a perfectly competitive market – can have, in principle, some ability to raise price above marginal cost: all that is required is that the firm faces a downward-slopping demand curve. Indeed, under some cost conditions, pricing at marginal cost would ruin the firm and is thus a precondition for financial viability.[14] Regulatory concerns arise only if the firm possesses significant and durable market power leading to prices that substantially deviate from proper economic costs and which generate persistent supracompetitive returns. When a firm possesses substantial and durable market power, it is often said to possess "monopoly power." Additionally, a firm with market power may have both an incentive and ability to engage in market strategies designed to protect its monopoly profits and power to the detriment of competition and consumers.[15]

The existence of effective competition precludes the ability profitably to exercise monopoly power, and therefore, a finding that effective competition exists in a market is usually taken to be equivalent to a finding that no firm in that market possesses substantial market power. In the presence of effective competition, prices are driven towards economic costs and resources are allocated efficiently.

1. Applying an appropriate standard

In the real world – as opposed to the theoretical construct of perfect competition – most firms have some degree of market power (i.e., some degree of discretion over price).[16] Indeed, generally firms seek to gain advantages in the marketplace that will result in attaining some level of market power. Moreover, firms may acquire market power through means that are wholly consistent with the process of effective competition (for example, through innovation, superior customer service, or operating efficiency). Therefore, a useful framework for assessing market power needs to be sufficiently nuanced to distinguish between the possession of *any* market power which is consistent with effective competition and the possession of *substantial* market power which is not.

Once one appropriately abandons the standard of perfect competition as a benchmark for assessing how well the market performs, one must accept that there may be systematic deviations from that standard in terms of structure (*e.g.,* potentially concentrated market shares), behavior (*e.g.,* evidence of some control over prices), and

[14] For example, marginal cost pricing will fail to recover total costs if there are substantial fixed costs.

[15] Of course, firms generally strive to protect or enhance their market positions. Such quest for profits and market share is, indeed, an engine of competition and should not be discouraged. See, for example, Jeffrey Church and Roger Ware, Industrial Organization, Irwin/Mc-Graw Hill, Boston (2000).

[16] On the divergence between the theoretical ideal of perfect competition and real world markets, see for example, Dennis Carlton and Jeffrey Perloff, Modern Industrial Organization, Harper-Collins: New York, 1990, pages 92-94; Alfred Kahn, The Economics of Regulation, MIT Press: Cambridge, 1988 (reprint edition, original John Wiley & Sons, 1970), volume II, pages 44, 114.

outcomes (*e.g.,* systematic deviations from marginal cost pricing). Structural characteristics may portend the existence of market power, but, if the firm or firms with market power do not have the ability to use that power to harm the competitive process, then that firm or those firms do not have a *substantial degree of market power*. In such a case, the market may be deemed to be effectively competitive.

2. Market definition

The first step in determining whether a firm has market power is to identify the relevant market in which power is to be gauged. The mere fact that a firm may have a large market share in a putative market is potentially irrelevant to the issue of market power, if the market is improperly specified. In the present context, there are two relevant markets in which market power and its potential impact on competition needs to be assessed. These are: (1) the "upstream" market for natural gas production; and, (2) the "downstream" market for retail sales of natural gas.[17]

Markets are defined with respect to both product and geographic boundaries. Generally, if consumers regard two products as close substitutes for one another, then they are regarded as being in the same market. If two goods are viewed as very poor substitutes for each other (or are clearly unrelated goods), then they are in separate markets. Assessing the extent to which goods are substitutes for each other requires an examination of the responsiveness of consumers to changes in the relative prices of the goods under consideration, as we shall explain in detail below.

A proper market definition inquiry begins with the narrowest set of products (services) and geographic areas feasible and asks the question, whether a hypothetical monopolist over that set of products (services) could profitably raise prices by a small but significant and non-transitory amount.[18] If the answer is "yes," then the relevant market has been identified. If, however, in response to the price increase a sufficient number of consumers would switch to alternative services/products to render the hypothesized price increase unprofitable, then the market must be expanded to include those services to which consumers would switch, and the exercise is repeated. This exercise continues until the smallest set of products (services) and geographic areas is identified such that a "hypothetical" monopolist over these products (services) likely could impose a small but significant non-transitory price increase. From this perspective, then, the relevant market is comprised of a group of products and a geographic area in which a sole supplier could exercise market power.

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[17] There are also the downstream markets for local gas distribution and wholesale sales of natural gas. We are assuming that the downstream market for local gas distribution is a natural monopoly that is regulated and will not address the impact of potential market power over long haul pipeline services on local distribution competition. Furthermore, our analysis of the markets for natural gas consumption is not sufficiently detailed to distinguish between wholesale and retail trade. Similarly, we also have not tried to separate out the potentially disparate effects of market power on different classes of end-users (*i.e.,* large commercial, small to medium commercial, and residential customers).

[18] See, for example, United States Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, April 2, 1992.

Two goods are in the same market when they are good substitutes for each other. Two goods are deemed substitutes if an increase in the price of one leads to an increase in the demand for the other (*i.e.,* the cross-price elasticity of demand is positive).[19] Hence, the relevant market should include all those products that are close substitutes for the product in question and exclude those products which are either not substitutes or very weak substitutes for the product in question. Unfortunately, it is often not a trivial matter to obtain with econometric methods statistically meaningful estimates of all the pertinent cross-elasticities of demand. Moreover, even when such cross-elasticities can be estimated, there is still a threshold question of what is the proper cut-off for inclusion of the product in the relevant market.[20]

With a commodity product like natural gas, the basis for discriminating among different sources of supply depends on the terms of availability and the price. There are a number of reasons why one may observe a wide dispersion in gas prices in both upstream and downstream markets. In the upstream market, there may be substantial differences in the costs of extracting or processing gas from different production sources. In the downstream market, what matters is the delivered price of gas which will vary depending on the location of an end-user because of transport costs and because of the terms under which gas is provided to or consumed by the end-user (*e.g.,* average and peak consumption, guaranteed or as-available delivery commitments, etc.). Moreover, the price and the terms for availability may differ systematically based on the type of customer (*e.g.,* large commercial vs. residential consumers).[21]

The time horizon of the analysis may also impact how broadly the market is defined. With a longer horizon, the ability of users to substitute to other sources of supply in response to a price increase is likely to be greater, implying more elastic demand and higher cross-elasticities. For example, with a sufficiently long horizon, end-users can switch to alternative fuels (*e.g.,* oil) or sources of power (*e.g.,* electricity) in response to an increase in the price of natural gas, even if in the short-term such switching may be

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[19] The cross price elasticity of demand between good 1 and good 2 is equal to the percentage increase in the demand for good 1 when the price for good 2 increases by one percent, holding other prices constant. If this is positive, then the goods are substitutes; if negative, the goods are complements (see Pindyck, Robert and Daniel Rubinfeld, Economics, Third Edition, Prentice Hall: Englewood Cliffs, NJ, 1995, page 31).

[20] For example, wine is a substitute for beer, but we expect that the cross-price elasticity of demand for beer relative to wine to be much smaller than the cross-price elasticity between different brands of beer. The choice of what constitutes the appropriate cut-off level for identifying whether two goods are substitutes for the purposes of defining the relevant market will affect the dimensions of the market under consideration.

[21] Discrimination in the price or terms of availability may reflect differences in the underlying costs of serving different classes of customers or may reflect Ramsey pricing. For example, large commercial customers may require less customer service than residential customers (implying a lower cost to serve); or large commercial customers may have more stringent peak demand requirements than residential customers (implying a higher cost to serve). Alternatively, these differences may be due to the abuse of market power. Without considering the conditions under which the discriminatory practice arises, it is not possible to conclude from the observation of heterogeneous pricing and availability terms that there is substantial market power or that the public interest is being harmed.

limited.[22] The time horizon is also relevant for assessing the impact of long-term contracts, which can also account for substantial variation in delivered prices.[23] Finally, the existence of storage facilities or inventories may make it possible to substitute between current and future demand for natural gas.

All of these factors need to be taken into account in defining proper markets in which market power is to be assessed. These factors also complicate the definition of the relevant "price." However, these difficulties are not of such magnitude as to undermine sound public policy. Still, it is essential that the regulator makes clear the criteria used for inclusion or exclusion of the various services and products in the pertinent markets so as to assist all the parties in understanding the principles that underpin the ultimate decision regarding the need for coverage (or the lack thereof).

D. *Economic Assessment of Criterion (a)*

Criterion (a) calls for an assessment whether coverage of the pipeline would "promote competition" in "at least one" market other than the one for pipeline services. This test has been described by the Tribunal in the following way:

> "The Tribunal does not consider that the notion of "promoting" competition… requires it to be satisfied that there would be an advance in competition in the sense that competition would be increased. Rather, the Tribunal considers that the notion of "promoting" competition … involves the idea of creating the conditions or environment for improving competition from what it would be otherwise. That is to say, the opportunities and environment for competition given [coverage], will be better than they would be without [coverage]."[24]

Following this interpretation, we understand criterion (a) to be focusing on whether coverage would reduce impediments to entry in either the upstream market for the production of natural gas or the downstream markets for the delivery and sale of natural gas to end-users.

A reduction in entry barriers in either an upstream or downstream market need not automatically induce new entry. Because of other market frictions, entry may be slow in coming. Hence, criterion (a) cannot be taken to mean that coverage would rapidly induce entry relative to the no-coverage benchmark. Rather, we take the criterion to mean that coverage is justified if imposition substantially increases the overall competitive

[22] Moreover, the ability of different classes of consumers may vary systematically in their ability to substitute among alternative sources of supply. For example, large commercial customers are likely to be more readily able to switch to alternative sources of supply than are residential customers. Therefore, if demand is segregated on the basis of customer type, one may identify market boundaries differently.

[23] This variation may be the result of discounts or premiums for longer-term commitments or because of changes over time (*e.g.*, differences in *ex ante* expected prices and current spot rates).

[24] See *Review of Declaration of Freight Handling Services at Sydney Airport* (2000) 22 ATPR 41-754.

conditions in relevant market(s), including the likelihood of entry. Here, it is important to point out that the mere reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers (which includes price, conditions of sale, service, and so on). Interestingly, it is conceivable that criterion (a) might be satisfied if it were found to lower entry barriers in at least one market, while increasing entry barriers in another.[25] In any case, since the pipeline "connects" two separate markets – the upstream production market and the downstream retail market -- it is necessary to evaluate the ability of the incumbent pipeline to exercise significant market power at least in these two distinct markets. For example, it is conceivable that the incumbent may not be able to exercise market power in one of the markets but be able to exercise market power in the second of the two markets. As we shall see, such a possibility cannot be excluded on merely theoretical grounds.

In the present context, transport facilities between upstream natural gas wells and downstream retail markets are an essential component in the natural gas value chain. Without a way of delivering gas from the well-head to end-users in downstream retail markets there would be no reason to extract the gas and there would be no way for end-users to obtain the gas. If a pipeline is a bottleneck facility, potentially it can adversely affect competition in the downstream and upstream markets, as indicated in criterion (a). For example, by overcharging for gas transport, it may reduce the number of active firms in either market; or it may use the terms and conditions of access to the pipeline to disadvantage some firms and advantage others.[26]

There are two plausible reasons why the pipeline with latent monopoly power over transport might use this to impact competition in upstream or downstream markets. First, it may seek to do this to exploit and protect its monopoly position in the market for pipeline services. Second, insofar as it is (or plans to be) vertically integrated, it may seek to extend, protect, or exploit whatever market power it may have in either upstream or downstream markets.

To evaluate these competitive dangers, it is necessary to consider the competitive conditions in the upstream and downstream markets. For example, if the pipeline has a subsidiary operating in the downstream market, the pipeline may seek to use its control over transportation facilities to disadvantage its downstream rivals. Whether the pipeline could be effective in such a strategy will depend on the strategic alternatives available to the pipeline's downstream rivals (*e.g.*, the opportunity to switch to gas supplied by the EGP or the Interconnect would reduce any potential anticompetitive impact from discrimination by the MSP).

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[25] In this hypothetical circumstance, it still would be necessary to satisfy criterion (d), which requires that coverage be in the public interest.

[26] There is no certainty that the incumbent pipeline may engage in conduct that would be harmful to competition. It is well-known that a monopolistic supplier of an input may earn maximum profits if the downstream industry into which it sells the input is perfectly competitive.

1. Ability and Incentive to Abuse Market Power

In this section, we discuss the incentive and methods by which a pipeline with market power over pipeline services may seek to exploit its power to affect the conditions for competition in upstream or downstream markets.

a) Ability to charge monopoly prices for transport services

First, absent coverage or any other form of price regulation, the MSP may be able to set prices for transport services that substantially exceed its forward-looking, long-run economic costs.[27] This would have the effect of increasing the delivered cost of gas in the NSW/ACT markets, which would, in turn suppress demand for upstream production from the Cooper Basin. As we discuss further below, this appears to be the case under the current MSP tariffs.[28]

If aggregate demand for natural gas at a particular location (say, Sydney) is relatively inelastic at current prices, and because transport costs represent only about 10% of the delivered cost of natural gas,[29] the reduction in demand for pipeline services from a price increase is likely to be small. However, this does not mean that demand elasticity facing a given pipeline is per force also low. The elasticity of demand for a given pipeline's transport services depends not only on the ability of customers to switch to other fuels but, also, on the ability to switch to other suppliers of gas. If the ability of end users to shift demand to other sources of natural gas away from MSP is also small at a "competitive" price,[30] then a price increase above that level would likely be profitable for the MSP. Indeed, as we discuss further below, the ACCC's draft access decision suggests that current rates are substantially above the pertinent economic costs.[31]

An increase in the prices for transport services above this benchmark competitive level could be partially offset by reduced margins earned by both upstream gas producers

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[27] The current prices charged by the MSP are not subject to regulation given the current status of the access undertaking submitted to the ACCC.

[28] Although the MSP is currently covered, there is no access arrangement in force because the one proposed by the ACCC is in abeyance pending resolution of the current proceeding. Therefore, the current tariffs are not subject to price regulations.

[29] Transmission costs accounted for approximately 10% of the delivered price of gas to residential customers, while local distribution accounted for between 40-50% of the delivered price. The share of the delivered price that is due to transmission is higher for large commercial customers who draw gas from the transmission network and do not pay local distribution or retailing charges (see *Final Recommendation Application for Coverage of Eastern Gas Pipeline (Longford to Sydney)*, National Competition Council, June 2000, page 26.

[30] Here, by a competitive price, we mean a price that earns MSP a normal rate of return (corrected for risk) and no more. We are not implying that this is the proper price benchmark against which prices in other industries must be gauged.

[31] See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, ACCC, December 19, 2000.

and downstream distributors.[32] Less than a full pass through of transport costs to end-users attenuates the reduction in demand associated with a price increase for pipeline services. Stated another way, the willingness of other economic actors to absorb some of the overcharge reduces the elasticity of demand for transportation services faced by MSP and thus enhances the incentives to elevate prices.

The incentive to elevate prices may be further reduced if the MSP is able to charge differential prices for transport depending on the source of the gas or its ultimate destination. That is, if it is able to price transport services differently to users based on their willingness-to-pay.[33]

The combination of lower upstream and downstream margins from above-competitive transport rates, will tend to reduce incentives to invest in both upstream and downstream markets and therefore could have an adverse effect on competition in both of these markets.

None of the above automatically implies that just because MSP is a natural monopolist in the provision of transport between Moomba and Sydney, it can set prices at the "monopoly level," meaning price without regard to the market. The MSP's ability to monopoly price is potentially constrained by competition in upstream or downstream markets. Regarding the upstream markets, if gas producers can sell their gas to other retail markets via other pipelines, they will refuse to sell gas to MSP unless they earn the same return on the marginal unit of gas shipped to Sydney (or ACT) as they earn on shipments to other locales. This type of competition will constrain MSP's ability to set transport prices substantially above economic costs, even if MSP remains a monopolist with respect to transport between Cooper Basin and the markets in NSW/ACT. Regarding the downstream markets, if there are other sources of natural gas supply to the retail markets in NSW/ACT then MSP cannot overprice transport since this would render the gas shipped over it uneconomic. As noted, this ability of consumers to switch to gas from other sources also constrains the MSP's ability to set transport prices substantially above economic costs.

Source and/or destination competition is an effective constraint on MSP, if there is sufficient independent capacity to absorb gas output on pipelines going to other destinations and if there is sufficient volume of gas output from other sources to which consumers can divert their demand in the face of elevation in price of the gas delivered over MSP. If these conditions are met, a substantial price increase above the competitive level will likely be unprofitable. This is so, despite the fact that the pipeline (here the MSP) is actually a natural monopoly over transport from the Cooper Basin to NSW and ACT.

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[32] The extent to which higher transport rates would be absorbed depends on the various elasticities of demand and supply along the gas production and distribution chain.

[33] Importantly, differential pricing of transport is likely to be efficient since pipeline costs are largely fixed. When fixed costs are high, marginal cost pricing is not feasible. Instead, second-best (or Ramsey) pricing is socially preferred.

b) Ability to engage in explicit or implicit price collusion

If the MSP faces only limited competition in either upstream or downstream markets, then it is possible that market participants will be able jointly to implement above-competitive prices through explicit or implicit coordination.

There are two important questions to address in this context: first, whether collusion between pipelines is a reasonable concern in the Australian context; and, second, whether requiring asymmetric coverage of the MSP pipeline would reduce the likelihood that collusion would be successful.

We have not undertaken an independent inquiry as to whether collusion among the pipelines is either likely or feasible. However, we note that the number of pipelines serving the NSW/ACT retail markets is small and is likely to remain so for the foreseeable future. Each pipeline is likely to have substantial latent market power in its relevant pipeline service market (by the same reasoning as was used to justify the conclusion that the MSP is a natural monopoly) and thus may not be adequately constrained by other pipelines that compete with it in the source (gas field) market. Thus, based on these plausible facts, public policy concerns regarding coordinated pricing cannot be dismissed out of hand.

It is critical to note that the ability to sustain a collusive outcome does not depend solely on the number of competing pipelines. Indeed, there are many markets with a small number of participants that are effectively competitive. Other market characteristics also impinge on the ability of firms to charge prices that significantly exceed competitive levels. For example, if each of the pipelines has excess capacity and if it is relatively easy to price discriminate so as to offer deals to potential customers that are unlikely to be observed by the competitor pipeline then price coordination may not be sustainable. Long-term contracts and large-scale purchases are also thought to hinder cooperation.

Some have argued that coverage of the MSP actually enhances the pipeline owners' ability to sustain a collusive outcome because the disclosure requirements associated with third party regulated access make pricing transparent.[34] While this criticism of regulation is well-founded, it ignores the effect of regulation on constraining prices to cost-based levels. By constraining prices, regulation sets a benchmark for unregulated prices that can be used by buyers in negotiations with the unregulated pipeline(s). This could have a salutary effect on the overall prices. On the other hand, the requirement to price according to public tariffs tends to rigidify prices since the regulated firm cannot readily take advantage of a secret discount or surprise when deciding on a price reduction. Abstracting from the well-known costs and inefficiencies associated with regulation in general, we believe that coverage on balance would not facilitate collusion.

[34] See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 24.

c) *Other incentives and opportunities to distort competition in adjacent markets*

A pipeline with monopoly power over transport may seek to leverage its market power into either upstream or downstream markets. The potent paradox is that the more tightly is the pipeline regulated in the provision of its monopoly service (here transport of natural gas), the stronger are the incentives to adopt business strategies aimed at extending this market power to the unregulated adjacent markets, such as upstream production or downstream retail distribution. The rationale here is plain: since the pipeline cannot earn its full monopoly return on the "bottleneck" activity, it will strive to capture that return in some other activities. The net effect may be more harmful to overall efficiency and competition than the alternative regime where the pipeline is allowed to capture some of the potential return for the provision of its transportation service. Alternatively, pursuing the public policy goal of preventing or deterring such "leveraging" could lead to additional regulatory constraints on the pipeline and the concomitant regulatory burdens, costs, and inefficiencies. There are, frankly, no easy trade-offs in this area. However, to the extent that competition in the source and destination markets is at least reasonably effective, the concerns with anticompetitive leveraging (hence the need for active regulation) are commensurately lessened.

The value of pipeline services is directly linked to the value of upstream production in the Cooper Basin and the retail markets in NSW/ACT. That is, the pipeline is a co-specialized asset. If there are inadequate reserves or production from Cooper Basin or if demand for natural gas in downstream markets is inadequate, then the value of the MSP will be adversely affected since it is only useful for transporting gas between these two markets. To the extent that such strategies are available, the MSP will have an incentive to deploy them in order to enhance the value of its assets. These may be either pro-competitive or anti-competitive in either the upstream or downstream market, depending on the circumstances. For example, if the MSP has no ownership interests in either upstream or downstream markets and if the MSP has excess capacity, it may be inclined to promote increased competition in upstream and downstream markets to reduce margins (and prices) in both markets and to increase incremental demand for pipeline services. If the MSP has excess capacity, stimulating incremental demand for MSP services is likely to be quite profitable because variable costs are low (*i.e.*, most of the costs are fixed or sunk) and promoting competition in upstream and downstream markets will have the expected effect of reducing upstream and downstream prices, creating a larger opportunity for the MSP to earn profits on the provision of its pipeline services.

Alternatively, if the MSP has ownership interests in either upstream or downstream markets, it will have an incentive to discriminate in favor of its affiliate. This discrimination may take a number of forms, including charging lower prices for transport services or offering such services on unequal and inferior terms to non-affiliates in either the upstream or downstream market. As we noted, such discriminatory incentives are more potent the more constrained is its ability to charge profit-maximizing prices for transport. Moreover, such discrimination need not lead to an overall reduction in economic efficiency and result in harm to consumers. For example, by advantaging its affiliate(s), the vertically-integrated incumbent may put enhanced competitive pressures on its stand-alone competitors in the upstream or downstream markets.

In fact, the owners of the MSP do have substantial ownership interests in both the upstream and downstream markets. In the downstream market, AGL, which is a major owner of retail and local gas distribution facilities in NSW and the ACT, has a direct ownership and management role in the operation of the MSP. The pipeline is owned by the Australian Pipeline Trust, of which AGL holds 30% of the units; AGL owns 50% of Australian Pipeline Limited which is the trustee and manager for the Trust; and AGL's wholly owned subsidiary Agility Management Services which is responsible for managing the actual operation of the pipeline. In the upstream market, the EAPL and another AGL wholly-owned subsidiary, AGL Wholesale Gas Limited, are parties to a 30-year agreement to purchase gas from the South Australian Cooper Basin Unit Producers (SACBUP), which is the consortium of producers that control natural gas production in Cooper Basin.

The MSP's major ownership interest in the downstream market as set out above creates natural incentives competitively to advantage its affiliate. However, it must be recognized that the technical aspects of gas transport (such as the need to balance the network and control injections into and withdrawals from the pipeline) can cause the pipeline owner to favor its affiliates for reasons that have nothing to do with the incentives as described above but, rather, for reasons that are firmly grounded in pipeline economics. When such discrimination arises as a consequence of the efficiencies of vertical integration, overall efficiency would be harmed if the integrated pipeline could not extend preferential benefits to its affiliates.

2. The upstream market

With respect to the upstream market, the appropriate question to ask is whether there are gas producers over which the MSP might potentially exercise monopsony power. This naturally focuses attention on the producers in the Cooper Basin that use the pipeline in Moomba to deliver their gas to the NSW/ACT markets. The ability of the MSP to exercise monopsony power over these producers depends on the market power of these producers and the range of options facing the Cooper Basin for delivering their gas to retail markets that do not depend on the MSP. Because the MSP is the only pipeline between Moomba and Sydney, this means options for delivering the gas via other pipelines to retail markets other than the NSW/ACT. At the same time, as noted above, MSP has no alternative use for its pipeline but to transport gas to NSW/ACT. This creates a setting in which there is potentially bilateral market power (*i.e.*, market power both on the sell and the buy sides of the "market").

If there are many options available to the producers for selling their gas into other retail markets, then the MSP will not have any monopsony power in the upstream market.[35] The MSP will not be able to lower the price it pays to upstream producers, or equivalently, increase the price it charges producers for transporting their gas to downstream retail markets in order to earn supracompetitive profits.

In gauging the strength of this competition, it is important to examine the available capacity on these alternative pipelines as well as the retail prices of gas in the destination markets of these pipelines. If the aggregate capacity of these pipelines is small relative to total output of the gas field, the concern that transport to NSW/ACT may be overpriced is not necessarily obviated. For example, the dominant pipeline may "allow" its smaller rivals to bid for all the output that they can profitably take and then charge a supracompetitive rate for transporting the remaining share of gas output.

We understand that a substantial amount of gas from Cooper Basin is currently delivered to Adelaide via the Moomba-Adelaide pipeline, but that pipeline is at capacity. Generally, pipeline capacities can be expanded but it takes time as well as financial resources. We have no information that would enable us to opine on how likely such expansion is over the time horizon that is relevant to the decisions under the Gas Act. Nonetheless, the possibility of expansion by the pipelines serving the Cooper Basin must be taken into account when examining the market power of MSP and thus the need for coverage. In addition, one need also examine the likelihood of entry during the relevant decision horizon.[36] However, over the short term, when such an expansion in capacity is not feasible, it appears that alternative outlets for the sale of Cooper Basin gas are limited, which suggests the potential for the MSP to exert monopsony power.

The ability of the MSP to exert monopsony power also depends on the market power of producers. If producers have market power, then the ability of the MSP to exercise monopsony power will be constrained without coverage. Producers' market power depends on the availability of alternative outlets for gas as well as on their ability to "bargain" jointly with the MSP. To the extent that there is a danger of collusion among the incumbent gas producers and the MSP, coverage may lower entry barriers upstream by reducing the ability of the upstream incumbent gas producers to collusively foreclose access to the MSP. Of course, if there are other entry barriers into gas development in the Cooper Basin, then coverage may be of lesser importance to upstream competition.

We understand that current Cooper Basin production is under the control of a single consortium. Since this is the only gas that can use the MSP pipeline, it seems reasonable to presume that the consortium may have substantial bargaining power when negotiating with the MSP for pipeline services. However, absent coverage, the

[35] It will be recalled that monopsony power (or buyer power) results from increasing marginal costs of obtaining supply of the input (here, natural gas). There is also a possibility that the firm with buyer power may attempt to extract quasi-rents from gas producers who may have sunk substantial costs into the development and operation of the wells. Over the long-run, it is not possible for the buyer to extract such quasi-rents since the strategy leads to the exit of suppliers from the relevant market.

[36] Pipeline entry and expansion can be facilitated by the ability of the pipeline to secure supply by means of long term contracts.

consortium might be able to foreclose entry of new producers by signing a favorable long term contracts with the MSP.

3. The downstream market

Downstream competition is also an important constraint on the MSP's market behavior. Downstream, the focus is on the geographic markets that are served by distribution networks that currently purchase, or could purchase, gas delivered via the MSP. Identifying the appropriate downstream retail market or markets, is more complex than for the upstream market since it is possible that the downstream market may be effectively segmented either on the basis of end-user location or customer type. If this is the case, then it may not be possible to treat the NSW/ACT as a single market, but rather as a collection of separate geographic or customer markets. For example, some regional markets may only be served by the MSP and the ability to deliver gas via alternate pipelines or by some other means may be quite limited for the foreseeable future. Those areas within NSW and the ACT for which the MSP is the only feasible source of supply may benefit from coverage if it leads to lower transport prices and assured access to the pipeline. Of course, insofar as the MSP exercises monopoly power in the provision of gas transport service to these areas, it creates incentives for other pipelines to create "spurs" that might reach the monopoly service areas.

Furthermore, in downstream retail markets, it may be necessary to examine competitive alternatives that are available to different classes of users. The competitive alternatives available to large commercial, small commercial, and residential customers may be systematically different. For example, different classes of gas customers may be differentially able to substitute to alternative sources of supply in the face of a price increase in delivered gas. It is the customers with the most inelastic demand who may benefit the most from coverage.

Of course, if the MSP is not able to set differential prices for transport destined for different categories of buyers and located in different areas, the issue of segmentation is moot. That is, absent the ability to set differential prices for transport, it may be reasonable to treat the NSW/ACT as a single market. We have not seen any data that suggests that a more fine grained segmentation of the market is warranted, but additional data might suggest that it is necessary to consider additional definitions of what constitutes the relevant downstream market for MSP services.

Irrespective of the actual delineation of the proper geographic market, the inquiry should focus on the availability of natural gas to the customers located in the relevant market from sources other than the Cooper Basin. Thus, even if MSP is the only pipeline capable of transporting gas from the Cooper Basin to NSW, say, this does not mean that the only natural gas available to customers in NSW can be sourced from the Cooper Basin. If the competition for gas customers in NSW is intense because there is significant pipeline capacity that can be deployed to deliver gas to NSW, then MSP will not be able to overprice transport without risking a significant diminution in demand for Cooper Basin gas and thus for its own transportation services.

III. Status of Pipeline Service Competition in South East Australia

Ultimately, if the MSP faces effective competition in both the upstream (*i.e.*, Cooper Basin producers can sell their gas to other retail markets not served by the MSP) and the downstream market (*i.e.*, there are substitute sources of gas supply to the NSW/ACT retail markets that do not depend on the MSP), then the MSP will not be able to effectively exploit its presumed monopoly power in the provision of pipeline services between Cooper Basin and NSW/ACT. If this is the case, then coverage which would limit the potential for the MSP to abuse its notional market power would not improve conditions for competition in the upstream or downstream markets.

A. Is MSP engaging in monopoly pricing?

One of the best indicators of whether the MSP is able to effectively exploit its natural monopoly in the provision of pipeline services to the pertinent group of customers is whether current prices are substantially above long-run economic costs, which is the level that they should attain in the presence of effective competition. While there is disagreement among the participants to this inquiry as to what constitutes an appropriate estimate of economic costs, the ACCC's draft access order[37] calls for rates that are as much as 40% below current levels by some accounts.[38] Moreover, there is evidence that prices have fallen since the EGP began operation, which implies that the MSP's pre-EGP margins were even higher. If one assumes that the ACCC's estimates are accurate to within plus or minus 10 percent of the true level of economic costs, then this suggests that competition in the source and destination markets has not been -- and is not currently -- sufficiently potent to keep prices at levels that one would expect in effectively competitive markets.

Nonetheless, we must caution that "competitive" prices are notoriously difficult to estimate in network industries characterized by significant fixed costs and low variable costs. Furthermore, since a substantial share of the costs faced by MSP are sunk or fixed, if competition were robust, it is possible that prices might fall below long-run average costs in the short-run. In the long-run, firms must be able to recover their costs to remain viable. Consequently, over a sufficiently long planning horizon, prices must average out at levels that ensure recovery of full costs, including the cost of capital. If prices fall below such level for a sufficiently long time, investment in pipeline infrastructure will be deterred.

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[37] See *Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, ACCC, December 19, 2000.

[38] See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 39.

B. Structural features and prospects for effective competition

Focusing on the downstream market, there are a number of market features that bear on the assessment of the likelihood of effective competition in that market.

a) Commodity product

Natural gas is a commodity product. This means that consumers generally regard gas from different sources of supply as close substitutes and should be willing to switch among providers based on relatively small differentials in price. This increases the likelihood that effective competition from substitute sources of supply will constrain the ability of the MSP to exercise monopoly power.

Empirically, the ability of alternative sources of supply to offer effective competition would be supported by a finding that there is a high cross-price elasticity of demand associated with pipeline services offered by the MSP, EGP, or Interconnect; or in the delivered gas-prices for gas provided by the different pipelines in the NSW/ACT retail markets; or (less useful) in the well-head prices of gas produced in the Cooper or Gippsland Basins. While it seems plausible that the cross-elasticities are high, we are unaware of any empirical studies that provide a firm basis for gauging the size of the relevant cross-price elasticities.[39]

b) Long term contracting

Although the majority of gas is sold under long term contracts in both the upstream and downstream markets, we do not believe that these are likely to have a significant effect on the ability of alternative sources of supply to compete. First, the lifetime of the typical contract is relatively short compared to the horizon of entry decisions into upstream production or downstream retail markets. Second, *ex ante* anticipation of future pricing behavior ought to be reflected in current long term contracts and so dynamic competition among the pipelines in the market for long-term transportation contracts should also act as a constraint on current pricing. Third, upstream producers' or downstream retailers' entry incentives depend, among other factors, on the sufficient availability of demand for gas[40] and on the availability of sufficient transport capacity on alternative pipeline networks. If the marginal purchasers of service from the MSP have ample alternatives open to them, the MSP's ability to elevate prices above the competitive level would be significantly limited. Fourth, the prospects of capturing future demand and potential competition from future sources of supply ought to increase the volume of uncommitted demand available to upstream gas producers or downstream

[39] We have seen the comments made in the Tribunal's decision in relation to the EGP on cross-price elasticities and the evidence of Mr. Ergas from which it appears that comment is derived. In our opinion, the material does not provide a sufficiently reliable empirical basis upon which to determine quantitative magnitudes of the pertinent cross-price elasticities.

[40] That is, demand which is not under long-term contracts.

retailers interested in competing in the market. Fifth, the ability of entrants to pre-contract for demand prior to investing lessens the risk associated with the recovery of sunk investments and tends to lessen impediments to entry.

Based on the information we have seen to date, it appears that despite long-term contracts, there is (and there will be) a sufficient amount of uncommitted demand so that effective gas-on-gas competition is likely to be feasible.

c) Sunk costs

Because the costs of constructing a pipeline are largely sunk, it is unlikely that the MSP could succeed in inducing exit of whatever pipeline alternatives that may exist. In particular, this means that it is unlikely that the MSP could eliminate the capacity provided by the EGP to the market and reduces the likelihood that the MSP would pursue predatory pricing to harm existing competitors. However, the MSP may be able to deploy strategies that might deter the construction of competing facilities (*e.g.* via excess investment in committed capacity to signal to potential competitors the ability to compete aggressively in the market for pipeline services should additional competitors seek to enter).

Additionally, inasmuch as firms in the upstream and downstream markets have made sunk investments, the MSP may attempt to expropriate some of the quasi-rents associated with these investments. The threat of such *ex post* expropriation could distort entry and expansion incentives. The ability to engage in such opportunistic behavior is constrained by competition among pipelines for gas at the source and by the ability of downstream firms to obtain gas from other sources of supply. Indeed, as always, it is the forces of competition that attenuate the risks of expropriation of rents and quasi-rents. Moreover, insofar as either the upstream producers or downstream retailers have countervailing market power, the concerns about rent extraction are further reduced.

Coverage may reduce the risk of anticompetitive behavior associated with the threat to expropriation of sunk costs by constraining prices and the scope of feasible contracts for transport. While these effects may be salutary, restrictions on feasible contracts and on the ability of parties to freely negotiate transport arrangements also reduce the ability of market participants to respond to changing market conditions and could lead to inefficiencies. It is our understanding that there is nothing in the Gas Code which restricts the ability of parties to negotiate gas transport arrangements on any terms that they wish including negotiating at prices above the level of the reference tariff and there can be an incentive for a customer to do so in order to obtain certainty benefits deriving from a long term contract.[41] In this regard, the Gas Code does not prescribe the prices that the pipeline must charge but once an access arrangement is in place it does, in effect, set a benchmark price which parties will, inevitably, have regard to in their negotiations. From this perspective, then, the usual concerns with regulatory pricing

[41] However, to the extent that the reference tariff is not adjusted to reflect changing market conditions, coverage may create inefficiencies in the negotiated arrangements for transport.

rigidities are lessened as are the standard concerns with the inefficiencies that may result from even the best-intentioned regulations.

d) Excess capacity

There is evidence that every pipeline that competes for delivery of gas to the NSW/ACT markets is expected to have excess capacity during the next 10 to 15 years. As data in Exhibit 1 shows, there appears to be substantial excess capacity and reserves available to deliver natural gas from the Cooper and Gippsland Basins into the retail markets in NSW and the ACT. Taken together, this evidence suggests that competition between the EGP and MSP pipelines may offer an effective constraint on the MSP's ability to exercise monopoly power.

As one caveat to this conclusion we note the possibility that peak capacity constraints may attenuate competition in the downstream market(s). While a possibility, we are not aware of any reason to believe that this is likely to be a substantial factor over the relevant decision horizon.

The availability of pipeline capacity in the upstream market could be more of an issue. Although the Cooper Basin gas is being sold into other retail markets (demonstrating at least the potential for redirecting gas to other markets in response to a hypothetical increase in the price of pipeline services by the MSP), it appears that capacity on the most important alternative route, the Moomba-Adelaide pipeline, is likely to be constrained.[42] This means that the MSP may have monopsony power with respect to the residual production from the Cooper Basin field.

e) Inelastic market demand

Evidence that the market demand for natural gas is relatively inelastic means that price increases, if feasible, are likely to be quite profitable. This increases the risk from and the incentives for monopoly pricing (or, collusive oligopoly pricing). Furthermore, since pipeline services represent only a portion of the overall delivered cost of gas (while remaining an essential component), we would expect the market demand for pipeline services to be even more inelastic.

While the market price elasticity of demand is important, what is really relevant is the elasticity of derived demand for pipeline services offered by MSP. If there are available substitutes with a high cross-price elasticity of demand, then the own-price elasticity of demand for MSP services may be high. This would make a unilateral price increase by the MSP unprofitable.

[42] See Australian Competition and Consumer Commission 2001, Final Decision, Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System, September at pp 48, 129, 171, 174, 186 and 188.

f) High fixed costs, low incremental cost of pipeline services

Pipeline services are characterized by high fixed costs (associated with the pipeline itself) and rather low marginal (or incremental) cost of transport (at least as long as there is available capacity). This means that, up to capacity, the pipeline would find it incrementally profitable to transport additional gas even at a price that may be below long run average costs. It also means that price competition between the MSP and EGP could be quite aggressive, especially in the short-term. This is because the pipelines will ignore their sunk and fixed costs when setting prices. As a result, prices may fall below the level needed to sustain long-term viability.

Opponents of coverage of the MSP have argued that this cost structure also reduces the risk that the MSP might abuse any monopsony power it may have to limit access to the pipeline since its profits are likely to be maximized if it maximizes throughput.[43] This does not necessarily follow. If the MSP has monopsony power in the upstream market but faces effective competition in the downstream market (*i.e.*, the MSP takes prices as given in the downstream market), then its incentive to exercise monopsony power (by lowering the effective price it pays upstream producers) is reduced relative to the scenario where it also has downstream market power. However, this does not mean that such incentive is non-existent. And neither does it mean that low decremental costs (i.e., costs that MSP would avoid if it were to cut back on throughput) per force render the exercise of monopsony power unprofitable.

A similar logic also applies to the downstream end. Just because marginal costs are low, does not mean that the optimal pricing strategy is to fill the pipe to capacity. It is true, however, that low marginal costs and high fixed costs create incentives towards high levels of throughput.

In sum, coverage that restricts the MSP's ability to engage in monopoly pricing or exploitation of monopsony power may be expected to constrain prices for the critical input which might make entry more profitable (or less difficult) at the upstream and downstream levels.

IV. Conclusions

This memorandum addresses the first two of the four criteria that must be satisfied to justify continued coverage of the MSP under the Gas Act. Our discussion shows that criterion (b) can be reduced to the examination of costs associated with the transport of gas between two points. We note that given the projected volumes of natural gas being shipped from the Cooper Basin to NSW and the ACT, it would be inefficient to

[43] See "Report in Support of Application to the National Competition Council for Revocation of Coverage of the Moomba-Sydney Mainline and the Dalton-Canberra Lateral Pipeline," Network Economics Consulting Group (NECG), August 2001, page 13.

construct a second pipeline. This suggests that pipeline-on-pipeline competition on that route is not likely to materialize. Hence, the MSP meets criterion (b).

Criterion (a) is more difficult to interpret, in our view. It asks whether coverage of the pipeline would reduce entry barriers in at least one upstream or downstream market. We take the relevant upstream market to be the production of natural gas in the Cooper Basin and the relevant downstream market to be the NSW/ACT retail market. Coverage may lower such barriers insofar as entry incentives are related to the rates for transporting gas and other elements of transport contracts that would be affected by coverage. Thus, if for example, coverage lessens the opportunities for anticompetitive differential treatment of firms that compete with the subsidiaries of the pipeline, the effects of coverage on competition may be quite salutary.

This does not mean that direct regulation is necessarily the rational policy response to the potential danger of abuse of market power. First, as is well known, regulation has its own costs and inefficiencies. Thus, the potential risks of removing coverage must be weighted against the benefits of lessening regulatory burdens. Second, there are a number of market factors that may constrain the ability of the MSP to exercise monopoly power over transport prices, despite the fact that the MSP has a natural monopoly in the provision of transport services between Moomba and Sydney. For example, competition in the upstream and downstream markets from substitute sources of demand (pipelines to other markets) or supply (gas from other sources of supply transported to the NSW/ACT markets) may be sufficiently potent to substantially restrict the ability of MSP to set rates that generate significant economic profits over a long haul. Third, high-volume long-term contracts and excess capacity (as well as other features of the market) may lessen the risk of coordinated pricing between the MSP and other pipelines. Admittedly, though, inelastic demand for natural gas tends to enhance such incentives. Fourth, general prohibitions against abuse of dominance can be sufficient to prevent the MSP from engaging in business strategies that harm non-integrated rivals to the ultimate detriment of competition and consumers.

In light of the limited evidence available (*e.g.,* a lack of good empirical evidence of the cross-price elasticity of demand for services from different pipelines or evidence that the consumers are actively moving demand among sources of gas supply in response to fluctuations in prices), however, it is premature to conclude whether these structural features are, on balance, consistent with a finding of effective competition.

Moreover, if one accepts the ACCC's estimates of the economic costs of providing transmission services as correct, the fact that these are much below the level of current tariffed rates, suggests that the MSP is apparently able to exercise substantial pricing power. To the extent the MSP is vertically integrated into upstream or downstream services (and it appears that the MSP is extensively integrated into downstream markets via the AGL), there is also a public policy concern that it may engage in business strategies that could disadvantage non-integrated rivals. Maintaining coverage may lessen MSP’s ability to deploy such strategies, but it is not without countervailing costs.

We have not engaged in a full-blown study that would enable us to opine whether the MSP meets the test for imposing coverage (or removing coverage) under the Gas Act. Our mandate has been narrower than that: we strived to offer some guidance regarding the possible interpretation of criteria (a) and (b) for imposing coverage. However, based on the limited data we have seen, we tentatively conclude that the case for removing coverage of MSP is not compelling. Plainly, MSP meets criterion (b). There is also evidence, albeit much less compelling, that MSP possibly meets criterion (a).

As stated at the beginning of this paper, it is not part of our role to make an assessment as to whether or not coverage is desirable and, in particular, we have not been asked to consider criterion (d). We would note that as a matter of policy it is important to recognize that regulation has its own costs and should not be mandated when the potential benefits from regulation are small relative to the inefficiencies and other burdens that regulation engenders.

Exhibit 1: Pipeline Capacities, Reserves and Demand
Average and Peak Current and Potential Capacity

	Annual Current Capacity (PJ/a)	Annual Potential Capacity (PJ/a)	Peak Current Capacity (TJ/d)	Peak Potential Capacity (TJ/d)
MSP	170[1]	292[2]	470[3]	800[4]
EGP	44[5]	110[6]	120[7]	300[8]
Interconnect	6.3[9]	70[10]	17.6[11]	
Total	210	402	531	1,100

Gas Reserves[12]

Reserves	Reserves (PJ)	Production (1999) (PJ/a)	Reserves (Years)
Cooper Basin	5,264	226.8	23
Gippsland Basin	8,084	201.4	40

Gas Demand in NSW[13]

	2000	2014
Demand (PT/a)	110	211

[1] See EAPL Access Arrangement Information provided to the ACCC, May 1999.

[2] See EAPL Submission Number 2 to the National Competition Council in support of revocation of coverage of the MSP.

[3] See EAPL Access Arrangement, note 1, *supra*.

[4] See EAPL Submission Number 2, note 2, *supra*.

[5] See *Duke Eastern Gas Pipeline Pty Ltd* [2001] ATPR 41-821 at 43,065.

[6] ACCC Draft Decision on EAPL Access Arrangement, December 2000, p7.

[7] See EAPL Access Arrangement, note 1, *supra*.

[8] See EAPL Submission Number 2, note 2, *supra*.

[9] See *Duke Eastern Gas Pipeline*, note 5, *supra*.

[10] NCC EGP Final Recommendation, footnote 18. This is lower estimate provided by EAPL of potential capacity.

[11] See *Duke Eastern Gas Pipeline*, note 5, *supra*.

[12] See Australian Gas Association, Gas Statistics Australia 2001, September 2001.

[13] See *Duke Eastern Gas Pipeline*, note 5, *supra*.

Our Ref: C1999/3
Your Ref: srd1416.7
Contact Officer: John Bastick
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13 September 2002

Mr Ed Willett
Executive Director
National Competition Council
GPO Box 250B
Melbourne VIC 3001

Dear Mr Willett

Moomba to Sydney Pipeline System – Application for revocation of coverage

I refer to your letter of 19 April 2002 concerning East Australian Pipeline Limited's application to the Council for revocation of coverage under the Gas Code of parts of the Moomba to Sydney Pipeline System (MSP).

In your letter you requested the Commission's views on a submission to the Council lodged by the Network Economic Consulting Group (NECG) on behalf of EAPL. In that submission NECG criticised the Commission's approach to determining reference tariffs in its Draft Decision on EAPL's proposed access arrangement. Moreover, NECG advocated the use of the 'hypothetical new entrant test' as a competitive price benchmark.

With respect to the hypothetical new entrant test, the Commission engaged the services of the National Economics Research Associates (NERA) to provide advice on this matter.

Enclosed is the Commission's response to NECG's submission together with the NERA report. I trust that the Council finds the material useful.

Yours sincerely

Joe Dimasi
Executive General Manager
Regulatory Affairs Division

THE HYPOTHETICAL NEW ENTRANT TEST IN THE CONTEXT OF ASSESSING THE MOOMBA TO SYDNEY PIPELINE PRICES

A Report for the ACCC

Prepared by NERA

September 2002
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EXECUTIVE SUMMARY

The Australian Competition and Consumer Commission (ACCC) has engaged NERA to critique a submission by the Network Economics Consulting Group (NECG) of 11 February 2002 to the National Competition Council (NCC). NECG's submission was made on behalf of East Australian Pipeline Limited and was in response to the NCC's draft recommendation on EAPL's application for revocation of coverage of parts of the Moomba to Sydney Pipeline System (MSP). We have also been asked to apply the hypothetical new entrant (HNE) test to the MSP and to compare HNE prices with those actually charged for use of the MSP.

In this context we have been asked to address the following four questions:

i. How should the prices that would be charged by a hypothetical new entrant be calculated in general and in the case of the MSP specifically?

ii. How do HNE prices compare with actual MSP prices?

iii. Is there an alternative test for whether or not current MSP prices are evidence of the exercise of market power?

iv. Which test is the best benchmark for the examination of MSP prices for the exercise of market power both in general and by the MSP in particular?

The Hypothetical New Entrant Test

We consider that the hypothetical new entrant test asks:

> *What is the maximum price an incumbent could charge if there was a credible threat of entry? In other words what is the maximum price consumers would be willing to pay an existing infrastructure owner if they had the hypothetical option to overcome transaction costs and negotiate as a coalition with a new entrant to provide substitute services?*

By assuming away the barriers to consumers acting as a unified coalition, the hypothetical new entrant test (hypothetically) removes the market power from the incumbent producers. It is therefore an attempt to derive a hypothetical 'competitive' market price for an industry that may not be competitive. When this is done in the case of the MSP we consider that the upper bound estimate of the hypothetical new entrant price would be given by dividing:

- The annual cost of a new pipeline from Moomba to Sydney given today's cost parameters; by
- the current ACT/NSW gas transportation quantities.

That is, we consider that the least cost method for supplying existing gas transport from the Cooper Basin to customers in the ACT/NSW would be based on a single pipeline serving that market (and therefore maximising the capture of economies of scale). This is an upper bound since it is possible that a pipeline from an alternative gas basin would lower costs.

We calculate that actual prices charged for use of the MSP are at least 30 percent in excess of HNE prices. For the Moomba to Wilton service this translates to a HNE price of $0.51/GJ compared with the MSP's current price of $0.66/GJ.

Network Economics Consulting Group (NECG) have argued[1] that an alternative approach is appropriate whereby the volumes used to derive prices in the above calculation are the current volumes on the MSP – which are lower than they would have been in the absence of the construction of the Eastern Gas Pipeline (EGP). However, we believe that this aspect of NECG's analysis is flawed. The correct approach, which divides the cost of a new pipeline by current NSW/ACT demand for gas transportation, arises from the following logically compelling propositions.

- if NECG's methodology for calculating the hypothetical new entrant costs for the MSP is the correct methodology to apply today then it must also have been the correct methodology to have applied prior to the entry of the EGP;
- the entry of the EGP cannot by itself result in the hypothetical new entrant price rising ie, loss of sales to a new firm does not increase either the hypothetical entrant's costs or the resulting prices; and
- if current prices are higher than prices determined by the application of the NECG new entrant test *prior to* the introduction of the EGP then this is evidence of the exercise of market power, unless there have been cost and volume changes independent of the EGP's entry that fully explain those higher prices.

If this set of propositions is accepted then not only does it support our earlier conclusion (that MSP prices are in excess of HNE prices by at least 30 percent) but also provides an independent test for the exercise of market power by the MSP. Under this test we calculate that MSP prices prior to the entry of the EGP (of around $0.71/GJ for the Moomba–Wilton service) were at least 42 percent above hypothetical new entrant prices (of around $0.50/GJ). Since then MSP prices have fallen by around 7 percent to $0.66/GJ (on the Moomba – Wilton service) but remains over 30 percent above those hypothetical new entrant prices. This suggests that either:

- contrary to reasonable expectations, entry of the EGP somehow caused competitive prices to rise by around one third (from $0.50/GJ to $0.66/GJ); or

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[1] Critique of the ACCC draft decision of MSP tariff in the context of the hypothetical new entrant price. Appendix to EAPL February submission to the NCC on its draft decision on MSP revocation.

- more reasonably, that MSP prices are still substantially above competitive levels (ie, the MSP is exercising market power).

We are unaware of any arguments that can convincingly explain why the entry of a new firm results in competitive benchmarks increasing. As a result, we consider that MSP prices are still substantially above competitive levels and this is evidence that the MSP is currently exercising market power.

The Regulatory Contract Approach

The hypothetical new entrant test considers a firm's prices in relation to 'competitive' prices *at a given point in time*. Under this test, the firm bears the risks associated with market and technological changes, which could lead to under or over recovery of sunk investments.

In contrast, the regulatory contract approach would consider the firm's ability to recover its reasonable costs *over the life of the asset*. Under this approach, the firm is protected against market and technological risks (positive or negative) associated with the hypothetical new entrant test. At any point in time, the appropriate price under a regulatory contract may be more or less than the hypothetical new entrant price, depending on the extent to which the firm has recovered its investment through past pricing decisions and changes in market conditions. Under the regulatory contract approach, in combination with our assumption that consumers can act as a unified coalition, the firm achieves normal profits over the life of the asset.[2] If a firm breaks the regulatory contract at some point in time (or the contract lapses for some period) and attempts to earn greater than normal prices it can be considered to be exploiting market power – even if this does not involve pricing above the hypothetical new entrant price.

Arguably, the Gas Code provides a regulatory contract under which future prices for gas transportation are to be set. The Gas Code may be a reflection and formal embodiment of implicit past regulatory contracts or it may be a new regulatory contract – brought into force by legislators. In any event, if the Gas Code is viewed as a regulatory contract and if the ACCC's draft decision applies the Gas Code correctly then current prices on the MSP exceed those that would apply under the regulatory contract by over 40 percent.

Which Test is Appropriate?

The most appropriate test to use will depend on whether a regulatory contract currently exists going forward or whether future prices are expected to be set in accordance with the hypothetical new entrant test (ie, at 'competitive' levels). This will in turn depend on whether there has been any recent explicit decision to apply a regulatory contract to the MSP

[2] 'Normal' profits refer to that level that is just sufficient to attract capital under the comparatively low risk regulatory contract model.

(arguably such as coverage under the Gas Code) or whether past determinants of pricing are suggestive of an implicit regulatory contract.

In any event, our analysis suggests that current prices on the MSP would fail conceivable applications of either the hypothetical new entrant test, the regulatory contract test or a third test based on NECG's analysis plus the proposition that competition does not cause the competitive price to rise.

1. INTRODUCTION AND BACKGROUND

The Australian Competition and Consumer Commission (ACCC) has engaged NERA to critique a submission by the Network Economics Consulting Group (NECG) of 11 February 2002 to the National Competition Council (NCC). NECG's submission was made on behalf of East Australian Pipeline Limited and was in response to the NCC's draft recommendation on EAPL's application for revocation of coverage of parts of the Moomba to Sydney Pipeline System (MSP). We have also been asked to apply a hypothetical new entrant (HNE) test to the MSP and to compare HNE prices with those actually charged for use of the MSP.

1.1. Background

East Australian Pipeline Limited (EAPL) is seeking revocation of the coverage of two pipelines within the Moomba to Sydney pipeline (MSP) system under the provisions of the New South Wales (NSW), South Australian, Queensland and Australian Capital Territory (ACT) gas pipeline access regimes.

The National Competition Commission (NCC) is considering whether to revoke coverage of the MSP under the Gas Act.[3] The National Competition Council (NCC), in December 2001, released a draft recommendation that coverage not be revoked. This recommendation was based in part on the Australian Competition and Consumer Commission (ACCC)'s views reflected in its *Draft Decision Access Arrangements by East Australian Pipeline Limited for Moomba to Sydney Pipeline System* (Draft Decision), which calculated prices for MSP services substantially below current prices on the MSP.

On 11 February 2002, EAPL responded to the NCC's draft determination. Appended to this response was Network Economic Consulting Group (NECG)'s paper *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price*. NECG's paper argued that the NCC's reliance on the ACCC's findings was inappropriate. This was based in part on the claim that the ACCC did not set out to calculate the contestable market price but rather to apply the National Third Party Access Code for National Pipeline Systems (the Gas Code), which is not necessarily consistent with the hypothetical new entrant test that NECG argued would be appropriate for the NCC's purposes.

The MSP is the only pipeline system currently delivering gas from the Cooper Basin production fields to markets in NSW and the ACT in southeast Australia. The MSP is owned by the East Australian Pipeline Limited (EAPL), which is a subsidiary of the Australian Pipeline Trust. The Australian Gas Light Company (AGL), the gas distribution

[3] Coverage of a pipeline under the *National Third Party Access Code for Natural Gas Pipeline Systems* imposes a regulatory regime that requires the pipeline operator to submit to the Australian Competition and Consumer Commission (ACCC) an arrangement for third party access, imposes disclosure requirements upon the pipeline operator, and puts in place an access dispute arbitration process. Hereafter, we refer to the Code and the other relevant legislation such as the *Gas Pipelines Access Law* and the *Natural Gas Pipelines Access Agreement 1997* collectively as the "Gas Act".

company in NSW, owns 30% of the Australian Pipeline Trust and is a major gas retailer in ACT and NSW. AGL's subsidiary, Agility Management Pty Limited, is the physical operator of the pipeline.

Prior to 1998, the MSP accounted for almost all of the natural gas delivered into the NSW and the ACT retail markets.[4] The MSP was subject to coverage under the Gas Act provisions, which impose third party access requirements. However, no access arrangements for the MSP are currently in place under the Gas Act provisions.

In 1998, the previous owners of the MSP and the owners of a spur from the Victorian pipeline system jointly constructed the Interconnect pipeline to link the Victorian pipeline system to the MSP, thereby introducing another possible source of natural gas transport into NSW and the ACT through the existing Victorian gas network (although that pipeline was not built to serve a particular firm demand for gas, either into Victoria from the north or into NSW from the south, and since its construction has served no major firm gas customers in either direction).[5] In 2000, the Eastern Gas Pipeline (EGP) began operation, providing a source of natural gas transport from the major production fields in the Gippsland Basin to the retail markets in NSW/ACT. The EGP is owned by Duke Eastern Gas Pipeline Pty Limited and DEI Eastern Gas Pipeline Pty Limited and is operated by Duke Australia Operations Pty Limited (collectively Duke).

In January 2000, AGL Energy Sales & Marketing Limited, a related body corporate of AGL, petitioned the National Competition Commission (NCC) to subject the EGP to access coverage.[6] On 3 July 2000, the NCC made a recommendation to the Minister for Industry, Science and Resources (the Minister) that the EGP should be covered and in October 2000 the Minister determined that the EGP should be covered.[7] Duke appealed the decision to the Australian Competition Tribunal (the Tribunal), which revoked coverage in May 2001.[8] This prompted EAPL to apply to the NCC to revoke coverage of the MSP, which initiated the current proceeding. Meanwhile, in December 2000, the ACCC issued a draft decision for access regulation of the MSP that called for prices that were approximately 40% below those rates proposed by EAPL.[9]

[4] In 1997, 95% of the natural gas consumed in NSW was supplied via the MSP (see page 27 of *Final Recommendation: Application for Coverage of the Eastern Gas Pipeline (Longford to Sydney),* National Competition Council, June 2000).

[5] The Interconnector ties the Victorian system to the MSP system. Thus, while it increased the numbers of sources available to inject gas in the MSP system, it did not increase the number of pipeline companies serving the NSW/ACT destination market.

[6] For a pipeline to be subject to access coverage the Minister must be satisfied that each of the four criteria set forth in Section 1.9 of the *National Third Party Access Code for Natural Gas Pipeline Systems* are satisfied. The relevant criteria are cited in Section II below of this memorandum.

[7] See *Decision on Coverage of Parts of the Moomba to Sydney Pipeline System by Minister Nick Minchin,* 16 October 2000.

[8] See *Duke Eastern Gas Pipeline Pty Ltd* [2001] ATPR 41-821.

[9] EAPL proposed $0.71/Gj (in line with its published tariff) while the ACCC proposed $0.43/Gj for the initial tariff of the access arrangement period for the Moomba to Sydney mainline. See *Draft Decision Access Arrangement by East*

1.2. Scope and Structure of Report

This report addresses four questions:

i. How should the prices that would be charged by a hypothetical new entrant be calculated in general and in the case of the MSP specifically?

ii. How do HNE prices compare with actual MSP prices?

iii. Is there an alternative test for whether or not current MSP prices are evidence of the exercise of market power?

iv. Which test is the best benchmark for the examination of MSP prices for the exercise of market power both in general and by the MSP in particular?

Given these questions, this report is structured as follows:

- section 2 discusses the objectives of and rationale behind the hypothetical new entrant test, and the conditions under which it is a suitable test for exercise of market power. In addition, section 2 examines issues of significant importance in the application of the test to the MSP, such as the appropriate volume of services the new entrant can be assumed to supply;
- section 3 examines NECG's analysis of the application of the hypothetical new entrant test to the MSP;
- section 4 examines an adaptation of NECG's analysis that provides a related test for the exercise of market power that can be applied in the specific circumstances of the MSP;
- section 5 provides an empirical estimate of the hypothetical new entrant test and the test outlined in section 4 as they relate to the MSP;
- section 6 considers the application of an alternative test for the exercise of market power. This is a test of whether current prices are consistent with any contract between pipeline and regulators/customers. We also discuss how this test may be applied in the case of the Moomba to Sydney pipeline;
- section 7 provides concluding comments.

Australian Pipeline Limited for the Moomba to Sydney Pipeline System, Australian Competition and Consumer Commission (ACCC), December 19, 2000. EAPL, however, reduced its then published tariff to $0.66 from 1 July 2000, but at that stage lodged no revisions to its proposed access arrangement to accommodate the lower tariff. In a revised access arrangement lodged with the ACCC in June 2002, EAPL is now proposing $0.66/GJ as the initial tariff for the access arrangement period.

2. HYPOTHETICAL NEW ENTRANT PRICES

2.1. Objective of the Hypothetical New Entrant Test

A hypothetical new entrant test assesses the price the incumbent firm is currently charging against the maximum price it could charge without encouraging entry into the market *if it were subject to the threat of competitive entry.* In the case of a business, such as a pipeline, that displays the scale-economy features of a natural monopoly, a hypothetical new entrant test presumes that customers can form a coalition to purchase services from the new entrant as a group.[10] That is, the hypothetical new entrant test asks "are prices at a level that would encourage new firms to enter the market if entry and exit were not restricted". If the answer to this question is "yes" this may suggest that the incumbent is exercising market power. The test can be thought of as estimating "competitive" price levels for non-competitive industries, ie, for industries which are not subject to credible threats of entry.

Whether it is an appropriate regulatory goal to ensure prices are no higher than these hypothetically competitive levels is a separate question. Attempting to set prices of natural monopolies in the same way as prices of competitive industries may or may not be an appropriate objective. The price volatility associated with cost recovery in competitive markets may not be appropriate for markets with very long lived, dedicated and immobile assets. In addition, there may be a significant information burden placed on those carrying out the hypothetical new entrant test. However, such issues are beyond the scope of this report.

In this section, we first consider the theory behind the test and the role of new entrants in setting prices in competitive markets. We then discuss the application of the test to non-competitive markets in general and the MSP in particular.

2.2. New Entrant's Role in Setting Prices in Competitive Markets

It is useful to define the role of new entrants in setting prices, in competitive markets before fully defining and applying the hypothetical new entrant test in non-competitive markets. In competitive industries the maximum price an incumbent firm can sustainably charge for a service is set by the minimum economic costs that the most efficient potential new entrant[11] would incur in providing a service of equivalent quality. If prices are set above that level then this will attract new entry until prices and new entrant costs are once again equated (either by price reductions due to increased supply or by an increase in new entrant cost as the most efficient potential entrants become incumbents). Similarly, if prices fall below new

[10] Without such an assumption, the presence of scale economies can, in and of themselves, be a barrier to new entry.

[11] The 'new entrant' may be an entirely new firm operating in that market or it may involve an expansion of capacity at another firm already operating in the market. In this context, new entrant refers to additional capacity entering the market – whether this is through an existing or new firm.

entrant costs then this will prevent entry to (or promote exit from) the market until demand and supply again equate prices with new entrant costs.

In such an industry, incumbent firms have no *ex post* protection from adverse changes in demand or cost conditions. To see this it is instructive to examine the impact on prices and profits of incumbent firms in the following three adverse market scenarios.

- *An incumbent incurs higher costs than a potential new entrant.*

  The incumbent will be unable to recover that portion of its costs that are above new entrant costs.

- *A new, cheaper production technology becomes available.*

  Incumbent firms will be forced by competition to price "as if" they had invested in that technology – even if they had actually invested in a more expensive technology.

- *Market entry outstrips demand growth causing market supply to exceed market demand at new entrant prices (for example, if new entrants inaccurately assess cost or demand conditions).*

  Prices will fall below the level required to allow new entrants to recover their costs. The market will only re-reach its long run equilibrium when demand growth or supply exit restores the balance of demand and supply at the new entrant price.

While a competitive market does not provide any *ex post* protection from these types of market developments, it does provide *ex ante* compensation for the probability that they may occur. For example, if all market participants consider that there is a risk that a new cheaper production process will become available then potential new entrants will be less willing to invest in existing technology to enter the market. That is, potential new entrants will include the risk that new investment costs may not be fully recovered in their calculation of the cost of entry. As a result, maximum market prices will reflect the recovery of current least cost technology plus compensation for the risk of asset stranding based on the market's estimate of the probability, timing and magnitude of any potential technological advances. A similar compensation (positive or negative) will be included in current market prices for the market's expectations of future changes in demand conditions.

2.2.1. Prices not revenue relevant to hypothetical new entrant test

It is important to note that it is prices, not revenues, which are subject to the hypothetical new entrant test. This is because in a competitive market potential new entrants compare market prices with their own expected *unit costs* when deciding on entry. They do not compare their expected *total costs* with the revenues of existing incumbents - since the scale of operations amongst firms need not be the same.

This is an important issue because simply comparing the total cost of a hypothetical new entrant with the total revenue of an incumbent may give a misleading picture if the hypothetical new entrant would efficiently operate at a higher scale (ie, greater utilisation). This issue has not been addressed in Network Economic Consulting Group (NECG)'s paper *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price*. In that paper NECG consistently refer to the hypothetical new entrant test as arriving at the contestable *market price*,[12] however, NECG's conclusions are based on a comparison of hypothetical new entrant *total costs* with the *revenues* of the incumbent MSP. This approach effectively assumes that the output of the hypothetical new entrant and the incumbent will be identical – which need not be the case.

As a result, NECG uses the costs of the hypothetical new entrant to set the revenues of the incumbent. This is only equivalent to setting the "*market price*" in the special case where the hypothetical new entrant operates on the same scale as the incumbent. That is, revenues and prices will only be the same if the hypothetical new entrant is restricted by assumption from capturing any economies of scale the incumbent firm(s) have not captured.

The following underlines this issue by highlighting that it is the potential new entrant's unit costs that set market prices and not the potential new entrant's total costs that set an incumbent's revenues.

Irrelevance of HNE Revenue

Let us assume that all incumbent firms in an industry have invested in a production technology that results in an efficient scale of operation being the production and sale of 100 units of output. That is, production at 100 units minimises the cost of production per unit (say, $1.0 per unit). This means that any production of more or less than 100 units will result in higher than minimum unit costs. In equilibrium these firms will produce and sell 100 units at $1.0 dollar each for revenue of $100.

Now imagine a new technology is developed such that efficient scale for that new technology is 200 units and the unit cost of production at that scale is $0.6. Operating at efficient scale using this technology a potential new entrant will have total costs of $120 (200*0.6) which is greater than the revenue currently being received by incumbent firms. However, the threat of entry (or actual entry) will cause prices to fall to $0.6 rather than rise to $1.2 (which would be required for incumbent revenues to equal the total cost of the potential new entrant).

This example should make clear that the hypothetical new entrant test sets market prices directly and not incumbent revenues. Incumbent revenues will be affected by hypothetical new entrant market prices but will not be set by them – incumbent revenues will also depend on the level of sales achieved by the incumbent(s).

12 See section 6 "Consistent application of the hypothetical new entrant test" beginning on page 11.

2.3. Hypothetical New Entrant Prices in Non-Competitive Markets

In some market structures the threat of new entry is not credible and, as a result, incumbent firms have market power allowing them to set prices above the level associated with the least cost production technology. The threat of new entry will be reduced where:

- *Significant economies of scale exist relative to the size of the market – that is, the average cost curve is declining over a substantial proportion of the market.*[13]

  Under these conditions, even if existing prices are such that the incumbents are making above normal profits, the entrant must consider the impact of market sharing on its ability to recover its costs. The lower an entrant's expected market share, the higher will be its unit costs. This implies that existing prices may not be sufficient to cover the costs of all firms servicing the market following entry, even if these prices provide the incumbents with above normal profits prior to entry.

- *Significant sunk costs of entry exist (meaning that investment in entry to the market cannot be recouped should the entrant decide to exit).*

  In addition to the potential inability to capture sufficient economies of scale, the presence of sunk costs increases the magnitude of the costs that are at risk for the entrant.

- *Significant transaction costs exist amongst final consumers such that they are prevented from credibly threatening to form a coalition and bypass existing suppliers.*

  The entry-deterring effects of economies of scale can be avoided if consumers are able to commit to provide an entrant with sufficient market share to ensure that entrant could provide services at a lower price than the incumbents, while still recovering all its costs. Customers' ability to do this will be reduced if there are significant transaction costs. These costs could relate, for instance, to negotiating costs, exit clauses within existing contracts, the ability to commit future users, etc.

An industry characterised by significant economies of scale is sometimes referred to as having "natural monopoly" characteristics. In such industries, it may not be possible to rely on the threat of entry to constrain prices. The purpose of the hypothetical new entrant test is to provide an estimate of the level of prices that would exist *if entry were a credible threat*. In this sense, the hypothetical new entrant test can be viewed as determining the long-run prices that would exist if the market were subject to competitive entry. We note that this is not necessarily the same as the prices that would exist in a competitive market in the short term. As discussed above, prices in a competitive market may fall below (or rise above) new entrant levels for a period long enough to encourage entry (exit) into the market.

The hypothetical new entrant test asks:

> *"What is the maximum price an incumbent could charge if there was a credible threat of entry? In other words what is the maximum price consumers would be willing to pay an existing infrastructure owner if they had the hypothetical option to overcome transaction costs and negotiate as a coalition with a new entrant to provide substitute services?"*

By assuming away the barriers to consumers acting as a unified coalition[14] the hypothetical new entrant test (hypothetically) removes market power from incumbent producers. The hypothetical new entrant test, by definition, provides prices that reflect the long run equilibrium prices a competitive market would attain. That is, while a competitive market may set prices that deviate from new entrant costs in the short run (while entry or exit from the industry is occurring), the hypothetical new entrant test abstracts from the short run and calculates long run competitive price levels.

Non competitive markets may have one or more incumbent firms, however, the larger the number of incumbents the greater is the prima facie case that economies of scale not be significant relative to the size of the market, particularly if a number of incumbents serve a particular route in the type of spatially separated markets served by pipelines. That is, the larger the number of incumbents the greater is the presumption that the market is subject to the credible threat of entry.

The hypothetical new entrant test is the same whether there is one or several incumbents operating in the market. It simply asks what is the minimum price consumers could contract with a new entrant of efficient scale if there were no barriers to them doing so. If a new entrant could supply existing customers at a lower price than they are currently supplied, then this is the hypothetical new entrant price – irrespective of whether one or more than one incumbent firms currently service those customers. Similarly, where there are many incumbent firms the hypothetical new entrant test, properly applied, will give the same long run equilibrium price as would competitive forces.

2.3.1. Defining substitute services

The hypothetical new entrant test requires a concept of services that can substitute for those currently being provided. A narrow interpretation of this concept would be the identical services that are currently provided to existing customers. However, this definition is inappropriate since it could require the hypothetical new entrant to replicate aspects of the current services that are no longer (or never were) economically efficient.

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14 In the context of a conventional analysis of the existence of market power, this is equivalent to hypothesising the existence of a perfect demand side substitute.

For example, in the market for delivered gas at a particular location it is likely that customers will regard delivered gas from any gas field as a near perfect substitute. If delivery from gas field A is the least cost method of providing this service it would be inappropriate to constrain the hypothetical new entrant test to calculating the least cost method of supplying gas from gas field B. In a competitive market, if an investment is made in an asset that is not least cost then the owners of that asset are forced to price their service in a manner that is competitive with that price a potential new entrant would charge when using the least cost technology. This is just another way of saying that competitive prices do not protect investments in assets that are not least cost in a forward looking sense.

Similarly, an existing gas pipeline system may have a lateral pipeline that previously serviced some residents in a small town and a gas turbine electricity generator. However, the gas turbine electricity generator may have closed making the servicing of the residential customers in that town by a hypothetical new entrant uneconomic. That is, the benefits to the residents (their willingness to pay) of the lateral would be less than the hypothetical costs of providing it. In this situation it would be least cost to provide those customers with sufficient monetary compensation for their (hypothetical) loss of gas supply than to extend the (hypothetical) new pipeline to them.

As such, the least cost provision of substitute services should include the possibility of providing substitutes other than connection to the gas pipeline system but which leave existing customers no worse off. This may be in the form of monetary compensation or, in the above example, could be in the form of the provision of bottled gas.

A coalition of all customers can always achieve agreement on such compensation if it is more efficient and if negotiation between customers is costless. This is because a more efficient bypass creates greater gains than losses. These gains can, by definition, always be transferred amongst a hypothetical coalition of customers to ensure that all customers are better off.

2.4. Applying the Hypothetical New Entrant Test to Prices on the MSP

2.4.1. Who are the customers?

The relevant set of consumers who would be provided with the hypothetical option of bypassing existing infrastructure owners are all those customers of delivered gas in the relevant market in which the hypothetical new entrant will enter. It is these consumers who would be asked the hypothetical question "what price would you be willing to pay for existing services if you were free to negotiate *en masse* for their provision by a new entrant?" In the context of the MSP the relevant set includes all consumers (potential and actual) of delivered gas in the NSW/ACT market currently served by the MSP.

For the hypothetical new entrant test it is only necessary to consider final consumers of delivered gas despite the fact that a gas pipeline provides a service to "upstream" gas producers as well as the "downstream" purchasers of delivered gas. Gas producers require the pipeline in order to be able to sell their output to downstream customers, and final customers require the pipeline in order to be able to purchase gas from upstream producers. In general, the interests of upstream and downstream customers will be identical – to minimise the cost of transportation. However, in the context of the application of the hypothetical new entrant test, it is sufficient to treat final downstream consumers of delivered gas as the relevant customer group for the purposes of determining efficient bypass prices.[15] This is because upstream activities only have economic value to the extent that they serve final customers. Provided downstream customers are served in the most efficient (least cost) manner by a hypothetical new entrant, economic surplus is maximised and only issues concerning the distribution of this surplus amongst customers would remain.[16]

2.4.2. Where would the hypothetical new entrant pipeline be built?

For consumers of delivered gas in NSW/ACT the price of delivered gas includes both the well-head and transportation prices – that is, the service provided by a pipeline is part of a bundled good. These consumers would contract with the hypothetical new entrant pipeline capable of delivering the lowest cost delivered gas. Thus, it is possible that these consumers would contract with a hypothetical new entrant to provide pipeline infrastructure that is markedly different to the existing pipeline infrastructure.

However, it is not necessary to go to this level of complexity to compare hypothetical new entrant prices to those currently charged on the MSP – provided we are satisfied with calculating an upper bound estimate of new entrant prices. This is because, if the MSP is not the most efficient pipeline/gas field combination, then the MSP would have to charge at lower than the hypothetical new entrant price calculated 'as if' it were the most efficient pipeline/gas field combination. For this reason, unit costs calculated on the assumption that a pipeline from Moomba to NSW/ACT is the most efficient technology will provide an upper bound to the efficient hypothetical new entrant price estimate.

We note that it is perfectly possible that the least cost method for supplying gas to the ACT/NSW is not via a pipeline following the MSP's path. In particular we note that:

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15 We note that this does not imply that a pipeline only has market power if it has market power in the downstream market. A pipeline may have no market power in this market but still may be able to price above economic costs and effectively capture economic rents from upstream producers of gas. Rather, this analysis suggests that in the context of the hypothetical new entrant test, it is sufficient to examine the least cost methodology of servicing final customers of delivered gas.

16 In fact the theoretical exercise carried out assuming that upstream customers of the pipeline are included in the coalition will deliver precisely the same results as focusing only on downstream customers. This is because where the hypothetical least cost pipeline would connect existing upstream producers with downstream consumers their interests would be identical – to lower the unit costs of that pipeline. Where the least cost pipeline were to connect downstream consumers with a different set of upstream producers then, by definition, downstream consumers would be able to compensate existing upstream producers for any loss in rents (as the new pipeline would, by definition, create greater rents than are lost).

- the Gippsland basin is closer to the main gas loads in the ACT/NSW than is Moomba;
- the capital costs of the EGP are understood to be in the vicinity of $450m (or half the lowest estimated ORC available for the MSP);[17] and
- the EGP's entry (despite the existence of the MSP) suggests that the EGP is a lower cost pipeline/gas field combination (or longer-lived, reflecting larger Gippsland reserves) or that the EGP was built in an attempt to capture monopoly rents being charged to ACT/NSW gas consumers served by the MSP.[18]

With this in mind it is quite possible that the postulated upper bound, under the restriction that gas is to flow from the Cooper Basin, is considerably above the true hypothetical new entrant cost if that restriction were removed.

2.4.2.1. Consistency with 'point to point' service definition

There is no inconsistency with the adoption of a 'point to point' service definition[19] for existing pipelines and the fact that the hypothetical new entrant test allows for the possibility of re-optimisation of existing pipeline systems such that all existing 'points' need not be served by the hypothetical new entrant. It is clear that an existing gas pipeline carries gas from one point to another point (or set of points). It is therefore sensible when considering the market power of an existing pipeline to recognise that it may have market power at any of these 'points' – eg, in the market for delivery of gas *from* point A and in the market for delivery of gas *to* point B (or at any intermediate points).

The hypothetical new entrant test simply allows for the (theoretical) possibility that the manner in which all 'points' are currently served is not the most efficient/least cost. It does not mean that one can ignore the manner in which 'points' are actually connected when performing actual (as opposed to hypothetical) market analysis.

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17 ACCC draft decision. This comparison of costs is only approximate as we note that the EGP is a smaller capacity pipeline than the MSP (both potential and actual) and the EGP could not serve a number of current MSP customers without the existence of the MSP (eg, those in Dubbo). However, the marginal cost of adding capacity at the time of construction are low relative to the total cost. That is, it is generally true that pipeline construction costs increase linearly in the diameter of the pipeline, while the capacity of larger lines increases exponentially. As such, a pipeline could be built by a hypothetical new entrant with double the capacity at much less than double the cost.

18 As a practical matter, it is well known the at the time the MSP was built, there were institutional and political barriers to the interstate trade in gas—barriers that have largely been eradicated with the reform of the gas sectors generally in Australia. Thus, the recent construction of the EGP may also partly reflect a generally closer, larger and less expensive supply of gas to NSW.

19 Refer to the Australian Competition Tribunal *Duke Eastern Gas Pipeline case*, 4 May 2001, in which the Tribunal found that the service provided by the EGP was the transportation of gas on a point-to-point basis. The Tribunal came to this conclusion when considering under section 1.9(b) of the Code whether it would be economic to develop another pipeline that provided the same services as the EGP.

2.4.3. What volumes would the hypothetical new entrant pipeline carry?

As discussed above, in the context of the application of the hypothetical new entrant pipeline the market is defined as the market for delivered gas in the ACT/NSW. In other words, final consumers of delivered gas in the ACT/NSW would choose the pipeline that minimises the unit cost of delivered gas to them. These customers are currently served by two major pipelines (the MSP and the EGP) that connect customers to two different gas fields. If this is the most efficient (least cost) pipeline network for delivering gas to final customers then the hypothetical new entrant test would replicate this network. That is, final customers would choose to contract with a new entrant (or two new entrants) that would build and operate two pipelines from different gas fields. The total costs of transportation charged to final customers would be based on the combined cost of the two pipelines (given current cost conditions).

However, if the current pipeline infrastructure is not the least cost network and if a single pipeline to one gas field would be more efficient, then final customers would bypass both existing pipelines by contracting with a single pipeline connecting customers with only one gas field. In this scenario a single hypothetical pipeline would supply the entire ACT/NSW market and its unit costs would be calculated on the basis of the cost of providing that volume of services. As discussed above, we do not need to know which gas field would be the most efficient supplier of gas to know that the unit costs of a pipeline that replicates the path of the MSP would be an upper bound for the prices the MSP could charge without attracting (hypothetical) bypass.

There are significant economies of scale in the gas pipeline industry. This reflects the fact that there are substantial fixed costs associated with constructing a pipeline (fixed in the sense that they do not vary with increasing capacity), such as the majority of design, surveying, site preparation and trenching costs. The cost of the pipeline itself also increases less than proportionately to increases in capacity. Increases in the volume of the pipeline increase the *diameter* less than proportionately and it is the diameter that is the main determinant of the cost.

This suggests that an appropriate *a priori* position is that a single pipeline is likely to be a lower cost way of providing transported gas to the NSW/ACT market than an infrastructure system comprising significant investment in more than one pipeline.[20] If this is the case, the new entrant price will reflect the cost of servicing the entire market from a single, efficiently built, pipeline. This price will depend on *total* market volumes, not the volume being

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[20] There are other potential benefits of having more than one pipeline serving a distinct set of customers, such as diversity and improved security of supply. However, these benefits must be larger than the additional costs of constructing additional pipelines in order that their construction is least cost in an economic sense. These net benefits will tend to be largest when there is a relatively even geographical spread of population and gas fields – such as may be the case in Texas in the United States. This does not appear to be the case in South Eastern Australia with gas loads centred around the geographically distant Sydney and Melbourne and gas fields in the equally geographically distant Cooper Basin and Bass Straight.

serviced by any single existing pipeline that may be sharing market volumes with alternative pipelines. In this way, the level of existing industry capacity does not affect the hypothetical new entrant test.

Such treatment of pipelines and volumes under a hypothetical test is entirely appropriate, since the purpose of the new entrant test is to abstract from issues of *existing capacity* in order to consider what unit prices would be with *efficient capacity*. In other words, the hypothetical new entrant test states that if having two pipelines is less efficient than having one pipeline the total cost of transportation paid by final customers should not increase simply because investment in two pipelines has taken place.

Prior to the introduction of the EGP the hypothetical new entrant would have set the average annual price for transport on the MSP equal to the total annual cost of bypassing the MSP divided by total market volumes transported on the MSP. That is, prices would have been set according to the least cost method of supplying the market. The entry of the EGP would have resulted in no change in the hypothetical new entrant price (other than that induced by any increase in volumes occasioned by the new rival suppliers to the region). By definition, any loss of volume from the MSP to the EGP cannot result in an increase in the least cost method of servicing the market as the hypothetical least cost method of servicing the market is unchanged by actual investment in the market (such as the EGP). However, any attempt to calculate the hypothetical new entrant price by reference to the actual volumes of the MSP would see a rise in the hypothetical new entrant price as a result of the introduction of the EGP (and the consequent loss of market share from the MSP to the EGP).[21] This is not only counterintuitive but inconsistent with a fundamental tenet of economics – that the entry of a new firm does not cause competitive prices to rise.

It is instructive to examine what would happen in a competitive market if new entry occurred that resulted in incumbents losing market share (ie, the additional capacity created by entry could not be fully utilised given market demand at pre entry market prices). This increase in market capacity would cause all firms to lose economies of scale and experience an increase in average unit costs. However, this would cause market prices to *fall* rather than *rise* as firms would have a strong incentive to attempt to win back market share and regain economies of scale. Prices would only return to pre-entry levels once the entry had been reversed or market demand had grown sufficiently to absorb the new capacity.

The hypothetical new entrant test sets prices based on long run equilibrium unit costs and hence it does not deliver a price fall as a result of capacity entry that exceeds demand growth. Rather hypothetical new entrant prices remain constant. However, it is important to note that short run competitive pressures could cause prices to fall as incumbents' capacity utilisation falls due to 'competition'. This is in contrast to the estimated increase in

[21] We note that this refers to a rise in the hypothetical new entrant price on the MSP. The fact that actual prices on the MSP fell slightly after the introduction of the EGP is consistent with these prices being above hypothetical new entrant prices prior to the introduction of the EGP.

the hypothetical new entrant price that would result if actual volumes on the MSP were used to calculate hypothetical new entrant prices following the introduction of the EGP.

2.4.4. Efficient investment versus profitable investment

The previous section states that a reasonable *a priori* position is that a single gas pipeline serving the ACT/NSW market is likely to be the least cost way of serving final customers. This does not imply that the construction of the EGP pipeline, given the existence of the MSP, was uneconomic in a 'commercial' sense. Most likely, the construction of the EGP has largely been driven by competition for rents in the production of upstream gas. However, commercially profitable 'competition' for economic rents (rent seeking) does not imply that the associated investment is economically efficient from a society wide perspective.

By way of example, imagine a pipeline from gas field A to consumers of delivered gas at B is in existence and that this pipeline is of sufficient capacity to service the market for delivered gas at B for the foreseeable future. Imagine also that the economic cost of gas at production field A is substantially less than the price received for that gas by producers – that is, there are significant economic rents being earned by the gas producers on gas supplied from A to B.

Imagine further there is a second gas field at C where gas becomes available at a cost that is significantly less than the price of delivered gas at market B. If the gas cost difference is greater than the unit cost of constructing a new pipeline from C to B (given forecast of achievable sales in B) then it may be commercially profitable to construct a pipeline from C to B. Essentially, the economic rents available in market B may commercially justify the costs of attempting to capture those rents.

The attempt to capture these rents is primarily an attempt to transfer rents from producers at field A to producers at field C. A simple transfer of economic benefits does not create any net increase in economic benefits. However, costs incurred in chasing that transfer of rent (the building of the pipeline from C to B) result in a commensurate reduction in net economic benefits. Unless there are additional benefits[22] to society as a result of the construction of this pipeline then the pipeline will be inefficient (ie, not least cost) in an economic sense but may still be commercially successful.

[22] These benefits may occur if, in the process of seeking economic rents, competition between gas field C and gas field A results in a substantial reduction in the wellhead price of gas at A which flowed through into a reduction in the delivered price of gas from A to B. However, any tendency for transport costs on the A to B pipeline to rise as a result of this competition would tend to offset any gains in economic benefits. In addition, any such reduction in the delivered price of gas at B would have to create sufficient additional demand for gas (and associated additional consumer surplus) to exceed the cost of building the pipeline from C to B.

2.5. Conclusion

The following is a summary of important conclusions from the above analysis:

- the hypothetical new entrant test asks "w*hat is the maximum price customers would be willing to pay an existing infrastructure owner if they had the hypothetical option to overcome transaction costs and negotiate as a coalition with a new entrant to provide a substitute service?";*
- the relevant substitute service in the context of the application of the hypothetical new entrant test to the MSP is the delivery of gas to the ACT/NSW market by an alternative pipeline system. This does *not* imply that a 'point to point' service definition is inappropriate for the MSP. Rather, it simply reflects that the fact that, in the context of the hypothetical new entrant test, the economic least cost method of supplying a market must be defined in terms of the costs imposed on final consumers;
- the hypothetical new entrant price sets the *market price* not the *revenue* of individual incumbent pipelines;
- the hypothetical new entrant price is unaffected by the actual level and type of investment that has occurred in supplying customers;
- there is an *a priori* reasonable assumption that a single pipeline from a single gas field is the least cost way of servicing a given market;
- on this basis an upper bound for the hypothetical new entrant price for transport of gas on the MSP can be calculated with reference to the total cost of bypassing the MSP and NSW/ACT market volumes; and
- if it is assumed, alternatively, that the hypothetical new entrant would only carry incumbent firm specific volumes (rather than market volumes) then the hypothetical new entrant test would suggest that prices should rise in the advent of 'competition' and loss of market share by the incumbent firm—an irrational outcome of such competition.

3. EAPL/NECG'S APPROACH

In their response to the NCC's draft determination, EAPL has put forward analysis performed by NECG in the document *"Critique of the ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price"*. In this document NECG have implicitly argued that:

- the 'hypothetical new entrant test' is the appropriate method for determining whether prices reflect the exercise of market power; and
- the 'hypothetical new entrant test' takes a particular form – namely it is assumed that the test compares current revenues from an infrastructure asset with the revenues just sufficient to entice a hypothetical new entrant to provide the same services currently provided by that asset.

Our analysis identifies shortcomings in each of these points. The first is NECG's failure to recognise that there are other tests that may provide suitable assessments of whether a firm is exercising its market power. In particular, the regulatory contract approach attempts to assess whether a firm earns higher than normal profits over the life of the asset. This is in contrast to the hypothetical new entrant test, which assesses whether prices at a given point in time are higher than would be implied by competitive market conditions.

The second shortcoming is that NECG relied upon *firm revenue* characteristics in its new entrant test rather than on *market price* characteristics. Under a competitive market, all firms face a given price. The new entrant test should therefore be *price* rather than *revenue* based. It is the least cost way of supplying the market and the market volumes that are relevant for determining the new entrant price. NECG's approach clouds the distinction by taking the cost base from the hypothetical new entrant test while protecting the firm from loss of market share by applying firm specific volumes. This tends to result in higher calculated prices for MSP and is similar to the 'cherry picking' of concepts which NECG accuses the ACCC.[23]

It is useful to list the critical points in which NECG's analysis of the hypothetical new entrant test concords with our own analysis and to show why we consider that NECG's findings are inconsistent with these aspects of their analysis.

- *"Contestable* ***market prices*** *can be estimated by applying the hypothetical new entrant test"* Page 11 (emphasise added)
    - We strongly agree with this statement and in particular with the emphasis we have added. However, the conclusions NECG reach are *not* based on the

[23] For example see NECG's paper "Critique of the ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price", p 12.

setting of market prices but, rather, are based on setting the revenue of a single firm in the market. Unfortunately, NECG's analysis does not consider the possibility that:

a) there is more than one incumbent firm in the relevant market; or

b) the hypothetical new entrant would not serve the market via a pipeline from Moomba to Sydney.

- *"A hypothetical new entrant is not likely to inherit the baggage of an incumbent, whether the baggage is unfavourable (such as obsolete equipment, gold plated assets or outmoded work practices) or favourable (such as peculiarities in the tax position of an incumbent or below budget construction outcomes on some assets)."* Page 12

  - We strongly agree with this statement and would add to the 'baggage' an hypothetical new entrant would not inherit 'poor capacity utilisation due to over investment in the relevant market'. For example, if two pipelines between Moomba and Sydney had been built side by side, resulting in poor capacity utilisation and high unit costs for both pipelines, an hypothetical new entrant would not inherit this 'baggage'. Similarly, if a pipeline from an alternative gas field had replicated some of the MSP's coverage and resulted in poor capacity utilisation on the MSP a hypothetical new entrant would not inherit this 'baggage'.

- "*Selectively adopting the best elements from each scenario (hypothetical versus actual) will not yield the contestable market price. If the hypothetical new entrant test is to be used effectively it must be used in its entirety.*" Page 12

  - We strongly agree with this statement but note that by using actual volumes on the MSP to calculate hypothetical new entrant prices NECG has committed precisely this error.

- "*A hypothetical new entrant must, according to the thought experiment, construct an optimal new asset*". Page 13

  - We strongly agree with this statement and note that an optimal new asset will be one that minimises the costs to final consumers of delivered gas. However, we note that such an asset need not connect Moomba to Sydney and assuming that it would without any further analysis only provides an upper bound of the hypothetical new entrant price.

The explicit (as opposed to implicit) statement by NECG that we most strongly disagree with is as follows.

- "*This test* [the hypothetical new entrant test] *asks what tariff level (or permitted revenue level) would just be sufficient to encourage an efficient hypothetical new firm to enter the market, assuming it could completely displace the incumbent service provider.*" Page 11

    - This statement implies that there is a single incumbent service provider and that the test would compare that firm's revenue with that a hypothetical new entrant would require. This ignores the possibility that more than one incumbent may operate in the market. We have explained that the hypothetical new entrant test requires examination of the least cost method of servicing the market – the number of actual incumbents in that market is irrelevant.

4. AN ALTERNATIVE HYPOTHETICAL NEW ENTRANT TEST

Section 2 above provides analysis suggesting that an upper bound estimate of the hypothetical new entrant test would likely involve postulating that:

- the hypothetical new entrant would incur costs associated with building a pipeline from Moomba to Sydney; and
- the hypothetical new entrant would capture close to all current ACT/NSW demand for gas transportation (and hence would capture greater economies of scale than are currently captured by the MSP).

By contrast, NECG have argued for an alternative approach whereby the volumes used to derive prices are the current volumes on the MSP – which are lower than they would have been in the absence of the construction of the EGP. However, we believe this aspect of NECG's analysis is flawed. The correct approach, divides the annual cost of a new pipeline by current market demand for gas transportation.

We believe our analysis stands on its own. However, we note that there is an additional (and distinct) test that can be applied to the reasonableness of our analysis compared to NECG's. This relies only on the acceptance of the following logically compelling propositions:

- if NECG's methodology for calculating the hypothetical new entrant costs for the MSP is the correct methodology to apply today then it must also be the correct methodology to have applied prior to the entry of the EGP;
- the entry of the EGP as a 'competing' pipeline cannot by itself result in the hypothetical new entrant price rising, ie, competition does not cause the competitive price to rise; and
- if current prices are higher than prices determined by the application of the NECG new entrant test *prior to* the introduction of the EGP then this is evidence of the exercise of market power unless there have been cost and volume changes independent of the EGP's entry that fully explain those higher prices.

If this set of propositions is accepted then, not only does it support our earlier conclusions but it also provides an independent test of the exercise of market power by the MSP. The MSP can be found to be exercising market power provided that its post-EGP pricing is above the 'competitive benchmark' levels that existed prior to the entry of the EGP - unless changed cost or demand conditions can explain the difference independent of EGP's entry.

5. EMPIRICAL APPLICATION TO THE MSP

In this section we calculate actual hypothetical new entrant prices which can be compared with those currently charged by the MSP. In order to do this it is first necessary to calculate the annual cost a hypothetical new entrant would incur in serving the market and second to transform this cost into a price (or set of prices) per unit of output which can be meaningfully compared with that charged by the MSP. This is done in the following two sections.

5.1. Estimating the Annual Cost of a New Entrant

There are a number of parameters that will affect the cost of a hypothetical new entrant. In particular these are the cost of:

- financing the capital involved in the project;
- depreciation in the value of the capital invested; and
- ongoing operating and maintenance costs (including the cost of tax).

We use the parameters outlined in the following table that are discussed in the following sections.

Table 5.1
Hypothetical New Entrant Cost Parameters

Parameter	Value)	Source
Real Post Tax WACC	6.28%	Calculated from below
Real risk free rate	2.87%	RBA 40 day average of 5 year bond rate at 9 August '02
Market Risk Premium	6.00%	ACCC Draft Decision
E/V	40%	"
D/V	60%	"
Asset Beta	0.50	"
Equity beta	1.16	Calculated using Monkhouse levering formula
Debt beta	0.06	ACCC Draft Decision
Debt margin	1.20%	"
Real cost of debt	4.04%	Calculated from above
Real cost of equity	9.65%	Calculated from above
Cost of Tax		
Gamma	50%	ACCC Draft Decision
Corporate tax rate	30%	Legislative rate
Nominal risk free rate	5.62%	RBA 40 day average of 5 year bond rate at 9 August '02
Expected 5 year inflation rate	2.67%	Calculated from real and nominal risk free rates
Replacement cost and depreciation	(in July 2000 $m)	
Optimised replacement cost	$976.1m	ACCC Draft Decision and NERA analysis
Life of asset	80 years	EAPL
Rate at which replacement cost falls over time	0.5% per annum	NERA analysis
Operating and Maintenance Costs	$12.18m per annum	ACCC Draft Decision

5.1.1. The Initial Capital Outlay of a New Entrant

Were a new entrant to serve the existing NSW/ACT gas market it would have to first build an alternative pipeline. An upper bound estimate of the cost a new entrant would incur in doing this is the optimised replacement cost (ORC) *of the MSP.* The ORC of the MSP is the cost of a new entrant in replicating the services provided by the MSP in particular the provision of gas from Moomba to customers currently connected to the MSP. However, as noted in section 2.4.2 above this is an upper bound estimate of the costs of a new entrant in serving the NSW/ACT as it is possible that the MSP is not the most efficient pipeline/gas field combination to serve that market. In which case a hypothetical new entrant would not be constrained to replicate the MSP but could instead build a pipeline to an alternative gas field.

We note that it is possible that a hypothetical new entrant would supply gas to the NSW/ACT market via a pipeline from the Gippsland basin – following a similar path to the EGP. In this regard we note:

- the Gippsland basin is closer to the main gas loads in the NSW/ACT than is Moomba (besides representing potentially greater reserves);
- the capital costs of the EGP are understood to be in the vicinity of $450m (or half the lowest estimate available for the MSP);[24] and
- the EGP's entry (despite the fact that the MSP existed) suggests that either the EGP is a lower cost pipeline/gas field combination or that the EGP was built in an attempt to capture monopoly rents being charged to NSW/ACT gas consumers served by the MSP.

Nonetheless, in our analysis we have adopted the ORC associated with the replacement of the MSP as our estimate of the cost of a hypothetical new entrant in serving the NSW/ACT market. The estimate of the ORC for the MSP used in the ACCC's draft decision is $976.1m in July 2000 dollars. This is effectively equal to EAPL's estimate of the ORC less the removal of a 10 per cent contingency factor included in the EAPL estimate.

We understand that the use of contingency amounts in planning the construction of assets such as pipelines is common practice. In this situation the contingency does not reflect the expected cost of the pipeline but rather reflects an estimate of the highest cost that is likely to be incurred above the expected cost of the pipeline. By definition it is equally likely that costs will come in under the expected costs as it is likely that they will exceed expected costs.

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24 ACCC draft decision. This comparison of costs is only rough as we note that the EGP is a smaller capacity pipeline than the MSP (both potential and actual) and the EGP could not serve a number of current MSP customers without the existence of the MSP (eg, those in Dubbo). However, the marginal cost of adding capacity at the time of construction are low relative to the total cost suggesting a pipeline could be built by a hypothetical new entrant with double the capacity at much less than double the cost.

However, it is sensible to plan for a contingency in which costs exceed expected costs in order to avoid the (potentially) costly requirement to negotiate further finance in the event of such cost overruns.

However, budget planning and market pricing are completely separate issues. If all firms in the economy priced as though their asset costs were 10% more expensive than in fact they were on average then there would be excessive profits being earned. This would in turn attract new entrants until prices were reduced to recover only the expected costs of a new entrant. It is for this reason that the appropriate ORC value to use in the context of applying the hypothetical new entrant test does not include such contingency costs.

5.1.2. Weighted Average Cost of Capital

The majority of a new entrant's costs in the years following entry will be the costs of financing the construction of the new pipeline system. These will in turn be determined by the risk adjusted rate of return demanded by the providers of capital used to finance the initial (and any later) capital investment. The magnitude of the risk adjusted rate of return is referred to as the weighted average cost of capital (WACC) – in practice most projects are financed by both equity and debt so the cost of capital is a weighted average of the cost of each funding source.

In our analysis we have used the capital asset pricing model (CAPM) in order to determine the WACC for a hypothetical new entrant. The CAPM estimates the cost of capital based on the riskiness of a particular asset relative to the market. The CAPM includes a number of parameters that are intended to reflect the riskiness of the individual asset/financing vehicle type (asset, equity and debt betas). All other things constant, the higher is the value of beta the higher is the riskiness of the underlying asset relative to the market – and the greater the compensation that those who finance the asset will demand. The other parameters in the CAPM (the risk free rate and the market risk premium) are intended to capture elements of the cost of capital that are determined independently of individual asset classes.

We have adopted the same CAPM parameters as adopted by the ACCC in its draft decision on the MSP[25] – with the exception of the observable risk free rates which we have updated based on more recent observations of yields on Commonwealth government bonds. Adopting the ACCC's assumptions and using latest observations of the risk free rate gives a

25 We note that a great deal of debate is possible on each of these assumptions and that many economists and finance experts will hold reasonable and different views on each of them. This length of this report could easily be increased ten fold if we were to examine each of these views in detail. In order to avoid this and minimise the scope for controversy we have adopted the ACCC's WACC assumptions. However, we note that NERA has argued in a submission to the ACCC on behalf of Incitec that the equity beta for the MSP should be no more than 1. The ACCC draft decision adopted an equity beta of 1.16 which adds over 1 percentage point to the return on equity above that recommended by NERA in that report. (See Comments on East Australian Pipeline Limited Access Arrangements On Behalf of Incitec Ltd by Jeff D. Makholm, Ph.D. Senior Vice President)

real post tax WACC of 6.28 percent. Given an initial capital outlay of $976.1m this translates to a first year capital financing cost of $61.3m.

5.1.3. Economic Valuation of Assets

In addition to the cost of financing the initial capital outlay of building a new pipeline asset the hypothetical new entrant would also have to be compensated for any loss in value of that asset over time. As the hypothetical new entrant operates in a competitive market paradigm the depreciation in the value of its asset must also be calculated in a competitive market paradigm. In a competitive market the value of existing assets is determined by what a new entrant would be prepared to pay for those assets rather than purchase new assets today. This is in turn determined by the expected profile of future costs associated with its use.

The ACCC's Draft Statement of Regulatory Principles of Transmission Revenues[26] provides a formula to calculate the value of an existing asset on the assumption that there is a constant annual rate of technological change reducing the cost of replacement assets. That formula gives the following relationship:

$$A_t = A_1 * (1-p)^{t-1} * (Z^L - Z^{t-1})/(Z^L - 1) \qquad \text{Eqn 5.1}$$

Where:	A_t	the economic value of the asset in period t
	p	annual rate of decline in the cost of replacing the asset
	r	discount rate (WACC)
	Z	equals $(1+r)/(1-p)$
	L	the economic life of the asset
	t	the age of the existing asset

In terms of its economic interpretation this formula calculates the benefit a potential new entrant receives in terms of delaying new capital expenditure if they were to buy the existing asset rather than build a new asset today. This benefit has two components, first by delaying the time at which new construction costs must be incurred it reduces the present value of those costs. Secondly, to the extent that replacement costs are falling over time it reduces the real cost of construction when it is actually constructed (eg, future construction of a pipeline at the end of the existing pipeline's life will be cheaper than construction of a pipeline today).

However, it should be noted that the above formula also implicitly assumes the operating costs associated with an existing asset are the same as the operating costs associated with a new asset and this is true no matter what age difference exists between the assets. There are two reasons to consider that such an assumption is conservative. First, it is likely that the

[26] The ACCC's Draft Statement of Regulatory Principles of Transmission Revenues, p 66.

operating costs of a hypothetical new entrant would be lower than the operating costs of the MSP due to two factors. A new pipeline would be able to take advantage of technological advances that were unavailable at the time of the design and construction of the MSP in order to reduce operating costs. Second, operating costs of almost all assets increase as the age of the asset increases. As a result, we would expect a new asset to have lower operating costs than the MSP, which is 24 years old, currently does. In our analysis we have assumed that the operating costs of a hypothetical new entrant would be the same as for the MSP and, in this regard, our approach tends to estimate an upper bound for the hypothetical new entrant test.

5.1.4. New Entrant Depreciation (and the Rate of Technological Change)

The higher is the rate at which new pipeline construction costs are falling in cost the greater will be the depreciation in the value of the hypothetical new entrants assets – and the greater the costs of a hypothetical new entrant. For example, an increase in the assumed annual rate of technological change ('p') from 0.0 percent to 1.0 percent increases economic depreciation from less than $1m to $10m in the first year of an asset's life (assuming an economic life of 80 years, a WACC of 6.28 percent and a year one construction cost of $976.1m).

5.1.4.1. NECG's estimate of the value of 'p'

A submission by NECG on behalf of EAPL estimates the value of 'p' to be between 1 and 2 percent per annum. The reasoning behind this is set out in the following quote.

> *"As built at the time, the MSP had a 60 year engineering life. Using present construction materials, technology, and methods an equivalent pipeline can be built for similar cost but providing an 80 year engineering life. In crude terms this is equivalent to 33% more service potential over a sufficiently long time horizon for a nearly equivalent cost. Looking at this at the level of very broad approximation, this could be interpreted as a 33% improvement in output over the 24 year period since the MSP was built. This is consistent with a 1 – 2% per annum average rate of productivity improvement."*[27]

However, the conclusion NECG draws from its evidence is wrong. If the initial construction cost of an asset is unchanging over time, a 1-2 percent increase in the life of replacement assets *is not* equivalent to a 1-2 percent reduction in the cost of replacement assets. Rather, what is relevant to the application of a hypothetical new entrant test is the rate at which the cost of capital expenditure by new entrants is falling over time. A one year longer asset life provides a benefit to a hypothetical new entrant by virtue of the fact that they are able to delay replacement of that asset by one year (many years into the future). The value of this

[27] Appendix B to EAPL's 11 February 2002 submission to the NCC. "Response to National Competition Council Draft Recommendation on Application for Revocation of Coverage of the Moomba-Sydney Pipeline and Canberra Lateral, p 3.

distant benefit must be discounted by the time value of money—and hence is much less than the percentage change in asset life.

If NECG is right that initial construction costs are unchanging but that the life of replacement assets is increasing annually by 1.2 percent[28] then the NPV of capital expenditure costs for a hypothetical new entrant are falling by less than 0.05 percent per annum (assuming a real discount rate of 6.3 percent). That is, the value of delaying expenditure on a replacement pipeline from 80 to 81 years (approximately 1.2 percent increase in asset life) is less than 0.05 percent (ie, one twentieth of one percent) of the current construction costs. This is far from 1.00 to 2.00 percent per annum reductions in replacement costs.

5.1.4.2. Historical estimates of the value of 'p'

For the purposes of the hypothetical new entrant test it is the rate at which the costs of pipeline construction can be expected to fall in the future which is important for determining the economic depreciation of the new entrant's assets. However, it is likely that the best indicator of technological change in the future is the rate of technological change in the recent past.

In this regard we have derived estimates of the historical rate of productivity change (p) by calculating the value of 'p' that sets:

- the rolled forward value of historical capital expenditure on the MSP pipelines (adjusted for inflation); equal to
- current estimates of the ORC of the MSP pipelines

The results of this analysis are presented in the table below. More details on are provided in Appendix A.

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28 A 1.2 percent per annum increase in replacement asset's life over 24 years gives a 33 percent increase over 24 years – which is the proportionate increase in asset life assumed for the MSP by NECG.

Table 5.2
Historical Rates of Technological Change

Pipeline*	Junee to Griffith	Young to Lithgow	Dalton to Canberra	Young to Wagga	Moomba to Wilton	Average weighted	Average unweighted
Annual reduction in replacement costs (p)[1]	-4.06%	-0.55%	0.64%	1.31%	0.46%	0.46%	-0.63%
Age (years)	12	12	18	18	23		
Annual reduction in replacement costs (p)[2]						0.07%	

* Data on the historical construction cost of the Wagga to Culcairn pipeline and the Young to Lithgow compressor are not available so this has been excluded from our analysis.

1 Using the ACCC ORC valuations.

2 Using the EAPL ORC valuation after deducting the ACCC ORC values for the Wagga to Culcairn pipeline and the Young to Lithgow compressor.

From this table it can be seen that using the ACCC's values for ORC the estimates of rates of reduction in replacement costs vary between negative 4.1 percent (suggesting replacement costs are rising 4.1 percent per annum) and positive 1.3 percent. For the total system weighted by the replacement cost of each pipeline the average is 0.46 percent that is also equal to estimated rate for the Moomba to Wilton pipeline (this is not surprising as the Moomba to Wilton pipeline accounts for 84 percent of the replacement cost of the entire pipeline). However, the unweighted average is a value of negative 0.63 percent. This unweighted average is influenced by the inclusion of a large negative value for the Junee to Griffith pipeline. While we have no reason to consider this observation less reliable than any other, excluding the Junee to Griffith pipeline gives an unweighted average of 0.16 percent. Excluding both the Junee to Griffith and the Young to Wagga pipeline (the pipeline with the other extreme observation) gives an unweighted average of negative 0.22 percent.

It is also relevant to note that the two most recently built pipelines both have the greatest negative productivity growth estimates associated with them. Given that we are interested in forecasting future rates of change in productivity estimates it is arguable that the most recent historical observations should be given the most weight. In light of all these issues we consider that it is probably most reasonable to adopt an assumption of zero productivity growth when calculating competitive market depreciation costs for the hypothetical new entrant. This is consistent with the use of the data provided by NECG discussed above (when properly interpreted).

Nonetheless, for the sake of conservatism we have adopted an assumption of 0.5 percent per annum in order to be consistent with our other assumptions – which are predicated on estimating an upper bound estimate of hypothetical new entrant costs. This assumption is greater than the weighted average of all pipelines. This result is also conservative as it allows for the possibility that observations on smaller pipelines may be biased estimates of productivity growth on larger pipelines (such as the Moomba to Wilton pipeline which accounts for the majority of MSP costs).

When this assumption of a 0.5 percent fall in replacement cost is used then the estimated cost of economic depreciation for a hypothetical new entrant in the first year of operation is $5.2m.[29] This compares to a value of $0.5m if an assumption of 0 percent productivity growth is used.

5.1.5. Non Capital Costs

In addition to the capital costs discussed above (capital financing and capital depreciation) a hypothetical new entrant will also incur operating and maintenance and taxation costs. These are discussed below.

5.1.5.1. Operating and Maintenance Costs

Operating and maintenance costs are those costs incurred in the delivery of a service in a particular year that do not contribute to the delivery of that service in future years (ie, that are not capitalised into the value of the underlying asset). We have assumed that a hypothetical new entrant would have the same costs as the MSP currently incurs. As discussed above this is likely to be a conservative assumption because a hypothetical new entrant would likely have lower operating and maintenance costs due to:

- technological change in the design and construction of pipelines since the MSP was built that minimises operating and maintenance costs; and
- the relative age of a new entrant asset compared to the MSP.[30]

The ACCC Draft Decision essentially adopts EAPL's estimates of operating and maintenance cost[31] which were themselves based on EAPL's actual operating and maintenance costs. We have also adopted this value of $12.2m in July 2000 dollars.

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29 Calculated on the basis of the other assumptions outlined in table 5.1

30 However, we should note that any inherent conservatism associated with the second dot point will be partially offset by a higher rate of economic depreciation. That is, if the costs of operating and maintenance rise with the age of an asset this will mean that the market value of that asset will fall faster than would otherwise be the case. This in turn would mean that economic depreciation would be higher than would otherwise be the case. Nonetheless, at any reasonable assumption for the annual rate at which O&M costs increase with asset age (less than 5.5 percent per annum) the depreciation in the value of a new entrant's asset in the first year of its operation due to rising future O&M costs would be less than the savings in actual O&M costs relative to the (24 year old) MSP.

31 We note that EAPL has since provided the ACCC with higher estimates of O&M costs (around 80% higher) but little in the way of firm explanation of these changes. In the absence of such explanation we consider it is prudent to continue to rely on EAPL's original estimates. Had we adopted this assumption then or finding that current MSP prices are significantly in excess of the HNE prices would not have been altered.

5.1.5.2. Tax costs

Our above estimates of capital financing costs are based on the post tax return that a hypothetical new entrant would require. However, income also attracts tax through the company tax regime, the cost of which will depend on:

- nominal income (which is itself a function of the inflation rate and the compensation for the above real costs, plus any compensation for the cost of tax itself);
- the level and timing of tax deductions under corporate tax law;
- the corporate tax rate; and
- the value to shareholders of any imputation credits associated corporate tax liabilities.

When all of these factors are taken into account in conjunction with the assumptions outlined in Table 5.1 above then a hypothetical new entrant has a negative cost of tax in the first year of operation of over $4m and this cost continues to be negative for several years thereafter. The reason for this negative cost of tax is that pipeline assets are depreciated for tax purposes over 20 years despite the fact that their economic life is around 80 years. This means that in the first 20 years of operation the cost of tax is significantly lower than it would be if tax depreciation was based on economic life. However, thereafter the annual cost of tax is significantly higher as tax depreciation has been fully exhausted.

It would be inappropriate to use a negative cost of tax in the first year of an hypothetical new entrant's operations when calculating hypothetical new entrant prices. This is because a competitive market would result in prices that allowed the cost of tax to be recovered over the life of an asset rather than in any given year. Indeed, given that at any one time there will be a number of firms with different asset ages operating in a competitive market then it is not possible to have a single competitive price which allows each firm to recover the cost of tax to it in that year where that cost of tax is dependent on the asset's age. Rather, the market will set a price based on the recovery of the net present value of tax costs over the life of an asset.[32]

In order to capture this we have calculated the annuity value of compensation for the cost of tax over the life of a hypothetical new entrant's asset and have included this in the calculation of the cost of a hypothetical new entrant in the first year of its operation. We

[32] More specifically, over the life of a new entrant's asset (to the extent that this may be different to that of incumbents).

calculate[33] this annuity value to be equal to $1.4m per annum that is consistent with a total NPV of compensation for tax equal to $18.2m.

5.1.6. Total Cost of an Hypothetical New Entrant

The above results are summarised in the following table where we calculate the upper bound estimate of the hypothetical new entrant cost to be $80.1m.

Table 5.3
Hypothetical New Entrant Costs

Cost Element	Value (June 2000 dollars)
Post tax return on capital	61.3
Depreciation	5.2
Operating and maintenance	12.2
Tax	1.4
Total	**80.1**

5.2. Estimating the Price of a Hypothetical new Entrant

As discussed in section 2.2.1, in a competitive market the hypothetical new entrant sets the market price incumbents receive, not the revenue that they receive. In order to transform the costs of a hypothetical new entrant (as set out above) into prices it is necessary to determine what volume of gas a hypothetical new entrant would transport. As outlined in section 2.4.3 we consider that the appropriate *a priori* assumption is that a single pipeline serving the NSW/ACT market will minimise the costs associated with serving that market, and therefore customers in that market would, given the opportunity, contract with a single (hypothetical) new entrant to supply their gas transportation needs. This means that the price a hypothetical new entrant would need to charge to recover its costs would depend on the entire NSW/ACT market for gas.

The purpose of applying the hypothetical new entrant test is to make a comparison with prices currently (and previously) charged for use of the MSP. To the extent that hypothetical new entrant prices are less than actual prices then this is deemed under that test evidence of the exercise of market power by the MSP over those periods. We calculate the relative average price for a hypothetical new entrant compared with the MSP as the ratio of the two prices, where the hypothetical new entrant price (P_{HNE}) is the ratio of its costs divided by

33 The assumed inflation rate used is 2.67 percent per annum. The assumed inflation rate impacts on the cost of tax in two offsetting ways. Higher inflation tends to reduce the real cost of tax due to the debt shield provided by nominal deductibility of interest costs for tax purposes. However, higher inflation also tends to increase the real cost of tax due to the fact that only depreciation of the historical asset base is deductible for tax purposes. In the current circumstances these effects almost exactly offset with no significant sensitivity of the results to increased assumed inflation rates (eg, an increase to an assumed inflation rate of 4 percent increases annuity compensation for tax by less than $0.2m).

total market volumes (V_{MKT}) and MSP's price (P_{MSP}) is the ratio of its total revenues and its volumes (V_{MSP}). The ratios of those two prices can be expressed as follows:

$$\frac{P_{HNE}}{P_{MSP}} = \left(\frac{HNE\ total\,\text{costs}}{MSP\ total\,revenue\,(associated\,with\,P_{MSP})} \right) * \left(\frac{V_{MSP}}{V_{MKT}} \right) \qquad \text{Eqn 5.2}$$

In other words, if the annual cost of a hypothetical new entrant (HNE) were equal to half the revenue MSP achieves at its current prices and if volumes transported were the same then the hypothetical new entrant would charge half of MSP's current prices. Similarly, if costs and revenues were the same but an hypothetical new entrant would transport twice the volumes as the MSP then hypothetical new entrant prices would be half those currently charged on the MSP. Finally, if MSP transports half the volumes at half the total costs of the hypothetical new entrant, then the prices are the same (and the ratio above is 1.0).

In order to put the above equation into practice it is necessary to know the ratio of HNE costs to MSP revenues and the ratio of MSP volumes to total market volumes in each relevant period. These we summarise in the following table.

Table 5.4
Cost, Revenue ($ July 2000) and Volume Figures

	1999	2001	2002
MSP volumes*	117.7	99.4	89.8
HNE volumes	117.7	116.1	114.8
MSP volumes/HNE volumes	**100%**	**86%**	**78%**
Hypothetical new entrant costs (upper bound)	80.1	80.1	80.1
MSP revenues	113.6**	88.9	81.2
HNE costs/MSP Revenues	**71%**	**90%**	**99%**

* These are volumes for the entire pipeline system. To the extent that the entry of the EGP has meant that average distances transported are now lower then our analysis is conservative.

** Calculated as 2001 revenues multiplied by the 1999 to 2001 ratio of Moomba-Wilton tariffs and the ratio of MSP volumes.

MSP volumes are taken from the NCC Draft Recommendation "*Application for revocation of coverage of parts of the Moomba to Sydney pipeline system*" page 48. The hypothetical new entrant volumes are calculated as MSP volumes plus volumes estimated to be carried by the EGP. The NCC estimates that in 2002 the EGP was supplying 25 PJ per annum into the Sydney region[34]. An efficient hypothetical new entrant would minimise unit costs and maximise economies of scale by carrying current EAPL volumes plus this additional 25 PJ/annum. The MSP and EGP volume figures for 2001 are affected by the completion of the EGP in August 2000 meaning it was only operational for 10 out of 12 months in 2001. In order to be conservative we assume the EGP was only operational for 8 months of 2001 and then only at an annual rate of 20 PJ/annum (which is equal to estimates of volumes

[34] NCC Draft Recommendation "*Application for revocation of coverage of parts of the Moomba to Sydney pipeline system*", p 52.

demanded by EGP's foundation customers). This gives a 2001 figure of 13.3 PJ supplied by EGP. Adding this to EAPL's forecasts of its own volumes in 2001 (of 99.4 PJ) gives a total market volume of 116.1 PJ. In 1999 the EGP was not yet built and, as a result, MSP and market volumes are assumed to be equal.

MSP revenue figures in 2001 and 2002 are based on forecast revenues taken from EAPL's access arrangement information and scaled down by 7 percent to account for the fact that EAPL's actual reference tariffs are approximately 7 percent lower than those set out in EAPL's access arrangement information. This is based on tariff for the Moomba to Wilton service that is \$0.66/GJ rather than \$0.71/GJ. It is only strictly true that this results in a 7 percent reduction in forecast revenues to the extent that all other prices are also 7 percent lower than as set out in the access arrangement information. For this reason we consider our approach to estimating MSP revenues in 2001 and 2002 is conservative. MSP revenue figures for 1999 are estimated as 2001 revenue scaled up for the higher 1999 reference tariff for Moomba to Wilton (\$0.71/GJ instead of \$0.66/GJ) and scaled up for the higher volume transported on the MSP.

Using equation 5.2 and the information contained in equation table 5.4 it is possible to estimate MSP average prices as a percentage of the hypothetical new entrant average prices in 1999, 2001 and 2002. These are set out in table 5.5 below.

Table 5.5
Hypothetical New Entrant Prices

	1999	2001	2002
Excess of MSP prices over HNE prices	41.8%	29.5%	29.6%

[1] Calculated as $P_{MSP} / P_{HNE} - 1$ (as per equation 5.2)

Applying this difference in the average HNE and MSP prices to the price for the Moomba to Wilton service allows for the following comparison in prices.

Table 5.6
Moomba to Wilton Price Differences

	1999	2001	2002
MSP price for Moomba to Wilton service ($/GJ)	0.71	0.66	0.66
HNE price for equivalent service ($/GJ)	0.50	0.51	0.51

The HNE price is slightly lower in 1999 than in 2001 and 2002 due to slightly higher volumes in that period. We note that we have not assumed that there would be any demand response to a reduction in prices to HNE levels. This makes our analysis particularly conservative as one would expect such a price reduction to cause a demand increase and, consequently, further reductions in unit costs as pipeline capacity utilisation increases.

5.3. Interpretation and Conclusions

The foregoing analysis and the results reported in table 5.5 suggest that in each of the last two years the MSP has been charging tariffs around 30 percent above an upper bound estimate of the hypothetical new entrant tariffs. This is evidence of the exercise of market power by the MSP. The reason MSP prices exceed new entrant prices by more than revenues is that the entry of the EGP in financial year 2001 has resulted in a loss of market share to the MSP and reduced MSP revenues towards new entrant levels but not prices received by consumers.

Our conclusion that current prices are evidence of exercise of market power is further buttressed by an application of the hypothetical new entrant test to the MSP prior to the entry of the EGP. Applying the hypothetical new entrant test prior to the EGP does not require one to accept the proposition that a hypothetical new entrant would carry entire market volumes because prior to the entry of the EGP market volumes and MSP volumes were identical (or very close to it).

Under this test we calculate that MSP prices prior to the entry of the EGP (of around $0.71/GJ for the Moomba–Wilton service) were at least 42 percent above hypothetical new entrant prices (of around $0.50/GJ). Since then MSP prices have fallen by around 7 percent to $0.66/GJ (on the Moomba – Wilton service) but remains over 30 percent above those hypothetical new entrant prices. This suggests that either:

- contrary to reasonable expectations, entry of the EGP somehow caused competitive prices to rise by around one third (from $0.50/GJ to $0.66/GJ); or

- more reasonably, that MSP prices are still substantially above competitive levels (ie, the MSP is exercising market power).

We are unaware of any arguments that can convincingly explain why the entry of a new firm results in competitive benchmarks increasing. As a result, we consider that MSP prices are still substantially above competitive levels and this is evidence that the MSP is currently exercising market power.

6. THE REGULATORY CONTRACT APPROACH

6.1. The Regulatory Contract Test

The objective of the hypothetical new entrant test is to assess whether current prices are higher or lower than would be expected if entry into the market were a credible threat. Under this test, past prices, revenues and costs are irrelevant to the determination of current prices. In this way, the hypothetical new entrant test provides a static assessment of whether a firm could be said to be abusing its market power *at a particular point in time*. However, it may be appropriate to consider whether the firm has exercised its market power *over the life of the asset*.

This will tend to be the case if past prices / revenues have been set on the basis of an explicit or implicit contract between owners and customers (or with regulators on behalf of customers) and that contract required future revenues or prices to have regard to past prices / revenues and costs. The distinction between the application of the hypothetical new entrant test and a test based on the existence of a regulatory contract is best understood by reference to an example from a competitive industry.

In a competitive industry firms have a choice of selling their output on the market at the market price (the ‘spot’ price) which, in the long run, is determined by new entrant costs. Alternatively, they have the choice of contracting with a purchaser to sell future output at a pre-agreed price – irrespective of the spot price in the future. Firms in a competitive industry may wish to enter into this type of contract to reduce the risk that falls in the spot market price result in an inability to recover sunk investment costs. Similarly, purchasers may wish to enter into such contracts in order to remove the risk to them of spot market prices rising above expected levels.

Consider the case where a new firm enters the competitive industry and, at the same time, enters into a long term contract with a customer to sell all their future output at a pre-arranged price (or according to a pre-arranged formula for setting prices) which ensures the recovery of all the firm’s sunk investment costs. It is possible that shortly after entering into this contract the market spot price (determined by new entrant costs) falls below the price set out in the contract. In this circumstance it is not reasonable to regard this firm as exercising market power even though it is pricing above new entrant costs.

It is also possible that after many years of recovering costs above new entrant costs the price set out in the contract falls below new entrant costs (spot prices) - either because this was an intended consequence of the contract or because new entrant costs unexpectedly rose above the contract price. In this situation if the firm were to increase its price above the contract price (ignoring the legal difficulties it may face in doing this) it could reasonably be considered to be exercising market power. This is true even if, in so doing, the firm did not increase its price above new entrant costs.

With this hypothetical example from a competitive market in mind it is possible to return to the examination of a natural monopoly industry. In a natural monopoly industry there will very often exist explicit or implicit contracts between firms and customers/regulators that provide a level of certainty to the firm that they will be able to recover their initial investment costs. The reason such agreements are common is due in part to the fact that natural monopoly industries, by definition, tend to require significant investment in long lived sunk assets.

Customers (or regulators on their behalf) may well be willing to enter into agreements with investors that provide a high level of certainty that, over the life of the asset, the investment owner will be able to recover the costs of the asset. One way of providing this certainty may be to 'front load' the recovery of investment costs on the basis that in later years cost recovery will be commensurately lower – with cost recovery over the life of the asset equal to actual costs incurred. If this is the case then it is likely that cost recovery in the early years of an asset's life will be above hypothetical new entrant costs and cost recovery in later years will be below hypothetical new entrant costs. There may also be circumstances where the converse applies, ie, if customers and investors arrange to 'back load' the recovery of costs, eg, where market demand is expected to grow significantly over the life of an asset.

This does not mean that an investor is exploiting market power in the early years even if it is pricing above hypothetical new entrant costs. Similarly, the fact that an investor may be pricing below hypothetical new entrant costs in the later years of the assets life is not proof that it is not exploiting market power. The correct test in the later years of the asset's life is "are prices above the level dictated by any relevant contract with customers/regulators".

The *regulatory contract* approach to testing for market power will be most appropriate when:

- the asset is part way through its useful life and:
    - past prices and revenues have been set under an implicit/explicit regulatory contract; or
    - a regulatory contract has recently been imposed after past above cost (monopoly) pricing of the asset;
- these regulatory arrangements have as an objective the provision of certainty of recovery of reasonable sunk costs over the life of the asset; and
- there has been an expectation that prices would continue to be set into the future under that regulatory framework arrangement.

6.2. Comparison of the Regulatory Contract and New Entrant Tests

The hypothetical new entrant test effectively gives consumers the benefit of technological advances and places the risk of these on the pipeline owner.[35] However, a natural monopoly is by definition not subject to competitive pressures. In recognition of this, consumers (or regulators on behalf of consumers) may choose to remove the uncertainty associated with the application of a hypothetical new entrant test, and remove the need to calculate and pay compensation to pipeline owners for anticipated technological change, by entering into a long-term contract or contract with infrastructure owners.

Unlike the hypothetical new entrant test, a long term contract provides asset owners with greater certainty over the recovery of their sunk costs in return for a commitment not to recover more than those costs. The regulatory contract approach effectively starts at a point in time and may limit the risk of stranding the pipeline owner is subject to from such things as:

- technological changes;
- changes in market demand; and
- changes to market share as a result of entry.

6.3. Applying the Regulatory Contract to the MSP

The first issue that must be addressed is whether a regulatory contract (either explicit or implicit) can be said to currently exist between the owners of the MSP and customers/regulators. In this regard it is pertinent to note that:

- the MSP was originally owned by the Commonwealth Government on behalf of citizens (including consumers of gas transportation services);
- in February 1994 the Council of Australian Governments agreed to put in place a uniform national framework for access to natural gas pipelines both within and between jurisdictions (the Gas Code);
- in the same year the MSP was sold by the Commonwealth under the *Moomba-Sydney Pipeline System Sale Act 1994*. The Act gave the ACCC responsibility for monitoring prices charged for use of the pipeline and the power to arbitrate access disputes including in relation to usage charges; and

[35] Technological change in this context is not limited to pipeline construction costs but also includes such advances as the discovery of gas at a site closer to consumers – such that the least cost technology for delivering gas to consumers is from that closer location.

- the ACCC's price monitoring role on the MSP was replaced by the ACCC's role under the Gas Code (the implementation of which was announced by COAG in 1997).

It appears reasonable to believe that the regulatory frameworks governing the past pricing of the MSP have had significant regard to providing owners of the MSP with certainty over the recovery of the sunk costs in exchange for a commitment that customers would not pay significantly more than the actual costs of the pipeline over its life. In particular, the Gas Code appears to have precisely these considerations in mind to the extent that it allows past cost recovery to impact on future prices. The ACCC's use of firm specific volumes to protect the owners of the MSP from financial losses due to loss of volumes to the EGP is also consistent with the interpretation of the Gas Code as a regulatory contract.

That is, the Gas Code appears to set out a regulatory contract between the owners of the MSP and its customers. In particular, by allowing past over recovery of costs to be offset against future revenues the Gas Code takes into consideration the long run recovery of sunk costs when setting prices.

If it is determined that a regulatory contract exists, there would be a number of implications for the assessment of the price level beyond which it can reasonably be said the owners of the MSP are exercising market power. In fact, the decision as to whether to use the new entrant test or the regulatory contract approach to determine the extent to which the MSP may be exercising market power will impact each of the factors used to calculate the maximum price. For example, compared to the hypothetical new entrant test:

- the asset valuation will no longer depend on the most efficient method for supplying the NSW/ACT market with delivered gas but will depend on the regulatory contract;
- the extent to which sunk costs have been recovered through past pricing decisions will be taken into account when setting the asset valuation in any given year;
- compensation for anticipated future technological change will be lower than that under the hypothetical new entrant test, reflecting the lower level of risk incurred by the firm; and
- the regulatory contract approach may determine revenues rather than prices, therefore, in setting prices the appropriate level of volume may be the firm's volumes rather than market volumes.

To the extent that the Gas Code represents the best description of the regulatory contract then the prices determined under the Gas Code may be a valid test of the exercise of market power. We note that the Gas Code allows for the departure from hypothetical new entrant prices on each of the above points.

7. CONCLUSIONS

In this report, we consider three alternative tests for exercise of market power for the period 1999-2002 for MSP:

1. The hypothetical new entrant test, which considers whether prices at a point in time are higher than those that could be expected to prevail under 'competitive' conditions. Under this test, prices are assessed on the basis of:

    - the current costs associated with the most efficient means of meeting market demand; and
    - market volumes.

    The application of this test exposes the firm to competitive costs associated with technological advances. Compensation for these costs must be incorporated into the test.

2. A test based on NECG's definition of the hypothetical new entrant test combined with the proposition that the entry of a new firm does not cause the competitive price to rise.

3. The regulatory contract approach, which allows a firm to recover its reasonable or agreed costs over the life of the asset. Under this approach, prices may be assessed on the basis of:

    - the level of investment and costs the firm is "allowed" to recover and the extent to which the firm has recovered this investment through past prices; and
    - the firm-specific volume of output.

The firm would not be exposed to the same magnitude of risks as under the hypothetical new entrant test, however, the compensation for those risks would be correspondingly lower.

The test that is most appropriate in any given situation will depend on the extent to which a regulatory contract can be said to exist. However, it is possible to apply all of these tests to the MSP's current prices. For each of the above tests we calculate that MSP prices are currently 30 percent above the maximum level at which we would conclude no exercise of market power is evident. As such, we conclude that MSP's prices for the period 1999-2002 reflect the exercise of market power.

APPENDIX A. HISTORICAL RATE OF PRODUCTIVITY CHANGE

Historical estimate of the rate of technological change (‘p’) on the Moomba to Sydney Pipeline (MSP) is calculated as the rate of ‘p’ that equates the historical capital expenditure on the MSP (in current prices) with the current estimates of the ORC.

To calculate the rate of technological change requires the following three steps:

- estimate annual historical capital expenditure exclusive of replacement capital in current prices;
- estimate the replacement cost of the assets to which the above historical capital expenditure relates; and
- calculate the rate of technological change per year that adjusts historical expenditure to be equal to replacement cost.

We base our estimates of replacement cost on the Venton and Associates Pty Ltd optimised replacement cost (ORC) study provided by EAPL to the ACCC and subsequently adopted by the ACCC with some amendments. We base our estimates of historical capital expenditure on the annual reports of the Pipeline Authority.

A.1. Historical Capital Expenditure in Current Prices

The historical capital expenditure is extracted from the annual reports of the Pipeline Authority and is reproduced in Table A below. It is necessary to adjust these figures from the Pipeline Authority as the purpose of these reports was to satisfy the laws governing company reports rather than to provide data on the historical cost of current assets. Therefore NERA has adjusted the reported capital investment to:

- remove any optimised and disposed assets;
- remove replacement capital expenditure; and
- adjust historical expenditure for inflation to derive current prices.

Removing Optimised and Disposed Assets

As the aim is to compare historic capital expenditure with current ORC estimates it is necessary to remove any historical capital expenditure on assets that have subsequently been either optimised or disposed of and are therefore excluded from the ORC estimates.

NERA’s understanding is that the only major asset disposed / optimised in the MSP network is the Moomba bypass. Therefore all capital expenditure and disposal revenue associated with the Moomba bypass has been excluded from our historical capital expenditure data. However, the Moomba bypass does highlight an important issue for our analysis. Although the annual reports show that the Moomba bypass cost over $23 million to construct they only show disposals of for just over $1.1 million. This is due to the financial nature of annual reports which report cash expenditures. To the extent that there are other disposals associated with the other pipeline assets where both the investment and disposal have not been removed our analysis will likely over state the initial capital base (and thereby ‘p’) as the cash raised by the disposals of asset tends to be less than the initial cost of the investment.

Removing the Replacement Capital Expenditure

In addition to the Moomba bypass vehicles, equipment and stores have also been excluded from the ORC and the historical capital expenditure data. This is because much of the historical value of this capital expenditure is in the nature of replacement capital expenditure (eg, replacement of a vehicle). If all such historical capital expenditure was included then it would be the equivalent of assuming that every vehicle purchased since the MSP’s inception is still in service and is included in the ORC. This is clearly not the case and the most accurate way to ensure that this form of ‘double counting’ does not occur is to remove such expenditures/assets from both the historical data and the ORC.

In addition, there are at least eight years during which investment on the Moomba to Wilton pipeline appears to be too small to be anything other than replacement capital.[36] We have used the average of those eight years as an estimate of annual replacement capital expenditure and have deducted this amount from the capital expenditure figures in table A for the years 1978-1993. We have not removed any replacement capital expenditure from any of the other pipelines.

Current Prices of the Initial Capital Investment

The initial capital investment and all subsequent capital investments have been scaled up by the ABS All Groups Weighted Average of Eight Cities Consumer Price Index.

A.2. Optimised Replacement Costs

As historical capital expenditures are extracted from the annual reports of the Pipeline Authority figures are only available from the period of 1977 to 1994. It is NERA’s understanding that the only major capital expenditure to occur from the period of 1995 to 2000 is the Wagga to Culcairn pipeline and the Young to Lithgow compressor. These figures have therefore been removed from the ORC calculations so that we are comparing the costs of the same assets.

[36] The years include, 1981-83, 1985, 1988-99, 1992-93.

The ACCC ORC[37] estimate from the draft decision has been reproduced in Table B with the assets to be excluded from our analysis highlighted. Table C shows the adjusted EAPL ORC.[38] As the EAPL ORC does not identify either the Young to Lithgow compressor or the Wagga to Calcairn pipeline asset values, the ACCC values for these assets has been deducted from the total ORC value given by EAPL.

We also note that to the extent there are any optimisations of existing assets in the ORC (other than the Moomba bypass – which has been excluded from historical data) our analysis will tend to bias the estimated value of 'p' above its true value.

A.3. Calculate the Implied Rate of Technical Improvement

The rate of technical improvement was then calculated by adding a productivity factor that annually reduced the productivity adjusted cost of historical capital investment until the productivity adjusted historical cost equals the ORC estimates. Using the ACCC ORC value implies a 'p' figure of 0.47 per cent for the weighted average of all pipelines in the MSP. As EAPL has submitted a higher 2000 ORC estimate this implies a lower 'p' factor with the estimate for the total system equal to 0.07 per cent.

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37 ACCC, Draft Decision *Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System*, 19 December 2000.

38 ACCC, *Op Cit*, Table 2.6.

Table A – Historic Capital Expenditure

Capital expenditure (estimates based on increase in historical cost asset values)

Year	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
	$'000																	
Moomba-Wilton	226,936	2,096	7,709	1,370	252	331	259	1,175	308	1,093	17,667	723	669	18,138	2,114	651	612	
Young-Wagga Wagga						20,413	94	7	-7	19	2							
Dalton-Canberra						8,709	176	-19	36	1	3	0	-1	0				
Moomba bypass							5,888	15,110	2,643	-661	-38	-405	-70					
Young-Lithgow												30,000						
Brewongle-Oberon												4,158	5	4				
Junee-Griffith																	10,957	8,148
Vehicles, equipment	98	22	23	29	-13	157	6	7	16	52	23	61	50	229				
Stores	48	12	7	18	20	5	14	4	16	7	1	47	-6	60	-23	8	36	
Total capital cost	227,082	2,130	7,739	1,417	259	29,615	6,437	16,284	3,012	511	17,658	34,584	647	18,431	2,091	659	11,605	8,148
Adjusted Capital Expenditure	226,936	2,096	7,709	1,370	252	29,453	529	1,163	337	1,113	17,672	34,881	673	18,142	2,114	651	11,569	8,148

Removed from Capital Expenditure

Table B – ACCC Adjusted ORC

	Moomba to Wilton	Young to Wagga	Wagga to Culcairn	Dalton to Canberra	Young to Lithgow	Junee to Griffith	Total ($000)
Pipelines	748,748	34,632	23,088	15,550	40,937	24,823	887,779
Compressors	49,732	0	0	0	1,815	0	51,547
Metering	9,410	1,063	709	1,906	4,211	3,185	20,483
Plant etc	8,678	383	256	188	504	301	10,310
Mobile equipment	5,050	223	149	109	294	175	6,000
Total	821,619	36,302	24,201	17,752	47,761	28,484	976,119
Adjusted ACCC ORC	816,569	36,079	0	17,643	45,652	28,309	944,252

Not in Capital Expenditure

Table C – EAPL OCR Estimate

	$'million
Pipeline – Moomba to Wilton	819.9
Pipeline – Young to Calcairn	59.4
Pipeline – Laterals	90.8
Compressors	58.1
Metering	14.0
Plant, Machinery, Equipment	10.3
Mobile Equipment	6.0
less	
Mobile Equipment	6.0
Young to Lithgow Compressor	1.8
Wagga to Calcairn Pipeline	24.1
Adjusted ORC	1026.6

RESPONSE TO EAPL/NECG SUBMISSION ON NERA'S APPLICATION OF THE HYPOTHETICAL NEW ENTRANT TEST

A Report for the ACCC

Prepared by NERA

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1. INTRODUCTION AND BACKGROUND

1.1. Background

In early September 2002, NERA provided the Australian Competition and Consumer Commission (ACCC) with a report discussing potential measures of the exercise of market power in the context of the Moomba to Sydney Pipeline (MSP) prices. East Australian Pipeline Limited (EAPL) and Network Economic Consulting group (NECG) on behalf of EAPL have responded to that report in late September 2002. The ACCC has engaged NERA to provide a critique of EAPL / NECG's response to our September report and this critique forms the remainder of this report.

1.2. Structure of Report

The remainder of this report is divided into:

- Section 2 which is a rebuttal of NECG's 6 main arguments as identified by NERA; and

- Appendix A which provides a rebuttal of NECG's interpretation of the academic literature.

2. REBUTTAL OF NECG ARGUMENTS/ASSERTIONS

NECG's critique of the original NERA report makes a number of arguments and assertions ranging over a large set of theoretical and empirical issues. Many of the arguments made by NECG are mutually inconsistent, lack relevance to the issues at hand or involve assertions regarding the contents of our original report that are demonstrably false.

A point-by-point rebuttal of each of NECG's arguments would tend to cloud the main areas of contention. In order to avoid this, we have organised NECG's criticisms into six main themes–relegating the detailed rebuttal of NECG's specific claims in relation to the academic literature to an appendix.

NERA interprets the six main themes raised by NECG as the following:

1. NECG states that applying "NERA's approach" would allegedly result in significant asset stranding risks with concomitant regulatory and incentive problems. NECG argues that the "NERA appraoch" is inconsistent with analysis provided by NERA in other areas (specifically in relation to telecommunications regulation);

2. According to NECG, NERA has failed to provide sufficient depreciation in the calculation of a hypothetical new entrant's (HNE) costs because NERA allegedly fails to take account of commercial practice and to fully compensate for asset stranding risks;

3. NECG alleges that comparison of the MSP prices to HNE prices is incorrect and inconsistent with the economic literature on market power. Rather MSP revenues should be compared to HNE costs when attempting to establish whether market power is being exercised;

4. NECG contends that even if the MSP is pricing above competitive levels this need not be considered exercise of market power as MSP may simply be capturing "Ricardian" rents from upstream gas producers;

5. According to NECG, NERA has incorrectly assumed that final NSW/ACT customers would choose to build only one pipeline rather than two – due to a failure by NERA to recognise redundancy and inter-basin competition benefits from the construction of two pipelines; and

6. The application of the regulatory contract approach proposed by NERA would justify tariffs that significantly over recover current costs in order to compensate for past under-recoveries.

We deal with each of these criticisms in turn.

2.1. Asset Stranding Risk and Investment Incentives

2.1.1. NECG position

NECG argues that calculating HNE prices on the basis proposed by NERA (ie, dividing efficient HNE costs by efficient HNE volumes) will result in:

- outcomes that are inconsistent with the gas code;
- asset stranding whenever bypass occurs that raises total pipeline costs – even if such bypass is efficient; and
- asymmetric risks that give inefficient incentives to delay investment.

2.1.2. NERA response

The critical flaw in NECG's report, is that neither NERA nor the ACCC advocate setting regulated prices equal to HNE prices. We propose to use HNE prices to inform the decision on *whether* to regulate the MSP – not on *how* to regulate the MSP. In fact, the ACCC has proposed to regulate the MSP's price based on MSP specific volumes, rather than on efficient volumes – ie, to fully compensate MSP's owners for the loss of volume it has suffered as a result of the entry of the Eastern Gas Pipeline (EGP). For this reason, a great deal of NECG's[1] report is arguing against a position that has not been advocated and is consequently irrelevant. As we stated on page 9 of our original report.

> *"Whether it is an appropriate regulatory goal to ensure prices are no higher than these hypothetically competitive levels is a separate question. … The price volatility associated with cost recovery in competitive markets may not be appropriate for markets with very long lived, dedicated and immobile assets. In addition, there may be a significant information burden placed on those carrying out the hypothetical new entrant test. However, such issues are beyond the scope of this report."*

NECG's discussion of stranding risk is only relevant to the question of whether NERA has correctly carried out the theoretical exercise of determining hypothetical new entrant prices. NECG argues that NERA has not provided sufficient compensation to a hypothetical new entrant for the risk of stranding. (Although we show in the next section that even NECG's suggested solution to this "error" still leaves the MSP pricing significantly above HNE prices.) NECG argues that NERA has ignored three reasons why a HNE might face stranding risk, namely:

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[1] For example, the entirety of NECG's section 6 "Appendix – The implications of adopting NERA's approach".

- if efficient bypass occurs resulting in a loss of volume on the HNE's pipeline (ie, a bypass that raises pipeline costs but provides additional benefits to consumers which exceed the increase in pipeline costs);

- if a HNE following the MSP route were to stop being part of the least cost pipeline infrastructure at some point in the future (eg, due to the discovery of a new low cost gas field next to Sydney); and

- if inefficient bypass occurs resulting in a loss of volume on the HNE's pipeline (ie, if a new pipeline is built that raises pipeline costs but does not provide additional benefits to consumers that exceed those costs).

NECG's criticisms in these respects are not valid. To see this, we examine our treatment of each of the above asset stranding 'risks' in turn.

Firstly, let us take the case of efficient bypass. Contrary to NECG's assertions, an efficient pipeline bypass that raises total pipeline costs *does not* result in *any* asset stranding under the NERA HNE test. This is clear from page 17 of our original report.

> *"As discussed above, in the context of the application of the hypothetical new entrant pipeline the market is defined as the market for delivered gas in the ACT/NSW. In other words, final consumers of delivered gas in the ACT/NSW would choose the pipeline that minimises the unit cost of delivered gas to them. These customers are currently served by two major pipelines (the MSP and the EGP) that connect customers to two different gas fields. If this is the most efficient (least cost) pipeline network for delivering gas to final customers then the hypothetical new entrant test would replicate this network. That is, final customers would choose to contract with a new entrant (or two new entrants) that would build and operate two pipelines from different gas fields. The total costs of transportation charged to final customers would be based on the combined cost of the two pipelines (given current cost conditions)."*

In other words, if downstream customers would rationally choose to build two pipelines then both pipelines would be included in the HNE cost structure and there would be no asset stranding of either pipeline when applying the HNE test.

Secondly, we have assumed that the MSP was the most efficient pipeline for the delivery of gas to NSW/ACT at its inception and that it remains the most efficient pipeline today. This is despite the fact that the mere entry of the EGP suggests that this may not be the case and that a HNE may therefore have considerably lower cost than the MSP. Page 16 of our original report addresses this issue directly:

> - *"the Gippsland basin is closer to the main gas loads in the ACT/NSW than is Moomba;*

- *the capital costs of the EGP are understood to be in the vicinity of $450m (or half the lowest estimated ORC available for the MSP);*[2] *and*
- *the EGP's entry (despite the existence of the MSP) suggests that the EGP is a lower cost pipeline/gas field combination (or longer-lived, reflecting larger Gippsland reserves) or that the EGP was built in an attempt to capture monopoly rents being charged to ACT/NSW gas consumers served by the MSP."*[3]

In other words, we have not imposed any asset stranding on the MSP despite the fact that evidence exists that it is not the least cost gas field/pipeline combination to serve the ACT/NSW market. Therefore, we consider that we have been highly conservative when dealing with the issue of asset stranding as we have assigned a zero probability to the possibility that the MSP is not part of the hypothetical least cost pipeline network supplying NSW/ACT. In any event, we state in section 5.1.4 of our September report that, based purely on historical evidence, it would be most appropriate to use a zero rate of technological change in our calculations. We nonetheless included a rate of 0.5 percent that we consider more than adequately compensates for any additional stranding risks – given that we have generously ruled out the Gippsland basin as a source of stranding risk.

Thirdly, it is inappropriate to compensate a HNE for asset stranding risk due to inefficient bypass. Conceptually, the HNE revolves around the concept that new entrants could never price above what a hypothetical coalition of consumers could build for themselves. Thus, in order for inefficient bypass to occur under the HNE test it would be necessary for the hypothetical coalition of consumers to decide collectively to build a pipeline which cost them more to construct than it provided in benefits. Including any positive level of compensation for this risk is illogical.

Of course, this does not imply that the risk of inefficient bypass is zero in the real world. On the contrary, if Moomba/MSP is truly the most efficient gas field/pipeline combination then the entry of the EGP must itself be an example of inefficient bypass that could only have been expected to be profitable precisely because the delivered price of gas on the MSP embodied sufficient monopoly pricing to make inefficient bypass profitable. A positive risk of inefficient bypass requires that the investors in that bypass perceive monopoly pricing by the incumbent gas field/pipeline *and* expect that monopoly pricing to be maintained after

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2 ACCC draft decision. This comparison of costs is only approximate as we note that the EGP is a smaller capacity pipeline than the MSP (both potential and actual) and the EGP could not serve a number of current MSP customers without the existence of the MSP (eg, those in Dubbo). However, the marginal cost of adding capacity at the time of construction are low relative to the total cost. That is, it is generally true that pipeline construction costs increase linearly in the diameter of the pipeline, while the capacity of larger lines increases exponentially. As such, a pipeline could be built by a hypothetical new entrant with double the capacity at much less than double the cost.

3 As a practical matter, it is well known the at the time the MSP was built, there were institutional and political barriers to the interstate trade in gas—barriers that have largely been eradicated with the reform of the gas sectors generally in Australia. Thus, the recent construction of the EGP may also partly reflect a generally closer, larger and less expensive supply of gas to NSW.

entry. The expectation that monopoly pricing will be maintained after entry is a necessary condition for inefficient bypass as some share of monopoly rents is necessary for the owner of the inefficient bypass assets to recover their higher cost structure. If either of these conditions do not hold then the risk of inefficient bypass must be zero. In other words, including compensation for the risk of inefficient bypass is itself tantamount to assuming that monopoly power exists.

2.2. Adequacy of NERA's Depreciation Charge

2.2.1. NECG position

In section 3.1 of its report NECG argues that NERA's year one depreciation charge of $5.2m is implausibly low. This is argued on the basis that:

- NERA's basis for adopting the depreciation schedule used is not set out;
- on a straight line basis, NERA's year one depreciation charge corresponds to a 188 year asset life; and
- NERA's use of market volumes instead of MSP specific volumes when calculating the HNE price imposes a significant risk of asset stranding for which NERA has provided no compensation.

NECG argues that these "flaws" can be corrected by calculating depreciation over a 30 year period (the period of a lengthy foundation contract) rather than over the asset's economic life. When NECG employs this approach it calculates an appropriate depreciation charge of $15.9m, compared to the $5.2m calculated by NERA in our original report.

2.2.2. NERA response

NECG's criticisms mix the concepts of economic and straight-line (or regulatory) depreciation. Firstly, we explained in sections 5.1.3 and 5.1.4 of our original report that our calculation of depreciation is based on the economic recovery of depreciation that would flow from a competitive market. Secondly, it is meaningless and misleading to discuss a "corresponding" straight line asset life in the context of economic depreciation. Thirdly, as discussed in the previous section it would be inconsistent to conclude that the hypothetical new entrant requires any additional compensation for stranding risk.

In any event, it is important to note that even if NECG's criticisms and its suggested solution were accepted, the MSP would still be found to be exercising significant market power. To see this note that NECG claim that the extra $10.7m depreciation charge is required in order to compensate a HNE for asset stranding risks.

> *"NERA's use of the competition depreciation formula, which is intended to reflect by-pass risks generally, not merely stranding due to technological change, inappropriately ignores the major source of asset stranding risk in this situation. That risk can be captured quantitatively within the competition depreciation formula, as the worked example below explains.*
>
> *The consequences of altering NERA's assumptions can be seen by assuming that capital recovery for an entrant, building facilities in a competitive market, should occur over a 30 year time period – the duration that corresponds to a lengthy foundation contract. If such a 30 year period were used instead of the 80 year engineering life, the year 1 depreciation charge using the NERA formula would be $15.9m, rather than the $5.2m NERA has in fact used."*[4]

However, adding $10.7m to the HNE's costs only increases HNE prices (calculated in line with NERA's September report by dividing HNE costs by market volumes) by around 13 percent. This would still leave MSP prices 14 percent above HNE prices (compared to the 30 percent calculated in our original report). NECG does not calculate HNE prices in this fashion. Instead NECG attempts to "have its cake and eat it too," in a sense, by arguing for higher depreciation due to stranding risk *and* then using MSP specific volumes to calculate the HNE price.[5] NECG can not have it both ways, if NECG includes compensation for the risk of stranding justified on the basis of the use of market volumes in the HNE price calculation then NECG must also use market volumes when calculating HNE prices.

2.3. Comparisons of HNE/MSP Prices Rather than HNE/MSP Revenues

2.3.1. NECG position

In section 4.1 of its paper NECG appear to infer that NERA's application of a hypothetical new entrant test based on a comparison of HNE prices with MSP prices is inconsistent with the literature. NECG claims the approach is "novel" and is:

> *"…inconsistent with the evidence the ACCC has led in a number of proceedings (including for example the section 46 proceedings involving parallel importation of CDs), acceptance by the ACCC of this test would clearly be a matter of significant importance to the public, as would any endorsement of this test by the NCC."* Page 12

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4 NECG, *Revocation of Coverage for the Moomba – Sydney Pipeline attachment in support of EAPL response to NERA/ACCC submissions*, September 2002, p. 24.

5 See the table on page 18 of the NECG report where NECG calculates the HNE price by dividing HNE costs (including $11m in higher depreciation) by MSP specific volumes.

NECG also seems to infer (but does not state outright) that NERA's description of the HNE test is flawed as it allows for the possibility that a firm may be exercising monopoly power but not earning monopoly profits.

2.3.2. NERA's Response

NECG's assertions are contrary to basic economic theory and are directly contradicted in the academic literature which NECG quotes in support its own analysis. Firstly, there is more than one test for the exercise of monopoly power and if NECG believe that the test as outlined in NERA's original paper in any way contradicts positions taken by the ACCC in other forums it would be better served to show this than assert it. We are certainly unaware of anything the ACCC has publicly stated in relation to parallel importation of CDs that is inconsistent with our analysis.

Secondly, there is no reason why the exercise of monopoly power must give rise to above normal profits on sunk assets. (For example, a patent owner can be expected to act as a monopolist and restrict supply to maximise net revenues. However, whether those net revenues are sufficient to return a profit on sunk research and development costs is a moot point.) In fact, any test for the exercise of monopoly power, such as that proposed by NECG on page 12, that *does not* allow for the possibility of the exercise of monopoly power resulting in a lower than normal return on sunk costs is fundamentally flawed and at odds with the economic literature.

The fact that monopoly profits do not always translate to monopoly prices is well documented, including in a paper by Mankiw and Wilson[6] which NECG itself invokes to support its own arguments (see section 4.3 of the NECG report). In that paper Mankiw and Wilson show that monopoly pricing is consistent with firms not earning monopoly profits. This is because under a range of conditions, prices will be raised above the prices necessary to recover efficient costs but that inefficient bypass will occur such that these monopoly prices are offset by inefficiently high unit costs. In the words of Mankiw and Wilson:

> *"…firms enter until all the collusive monopoly profits are dissipated into set-up costs. The welfare losses caused by free entry in this example are similar to those Posner (1975) describes in his discussion of competition for monopoly positions. In both cases rent-seeking turns monopoly profits into deadweight losses."* (Page 53)

So rather than our description of market power without above normal profits being 'novel' it is in fact deeply embedded in the economic literature – even in the literature that NECG quotes.

6 Mankiw, N. Gregory and Whinston, Michael (1986) "Free entry and social inefficiency", *Rand Journal of Economics*, 17, Spring, 48-58).

Leaving aside NECG's assertion that our test of market power is flawed, NECG have also conspicuously failed to address the fact that its own test, which compares HNE revenues with MSP revenues, would have calculated that the MSP was charging prices around 42 percent above competitive levels in 1999 (prior to the introduction of the EGP).[7] Since the introduction of the EGP, MSP prices have only fallen around 7 percent – leaving current prices still well above 1999 competitive levels – even as would be calculated by NECG. By not addressing this issue NECG fails to explain why NECG's test has the competitive benchmark increasing upwards of 30 percent with the entry of a new "competitor" in the form of the EGP.

We remain interested in NECG explaining why the test based on revenues that they propose (and which allows for the novel result that the entry of a competitor increases benchmark competitive prices by 30 percent), is more appropriate than the test outlined by NERA.

2.4. Ricardian Rents

2.4.1. NECG position

In section 4.4 of the NECG report it is argued that even if the MSP is charging unit prices above efficient unit costs then this is not necessarily evidence of the use of market power. It is argued that:

> *"…even if EAPL's unit prices and aggregate revenues (at notional efficient volumes) did exceed the long run costs of supply, the inference that EAPL revenues in excess of those costs reflect the exercise of market power does not follow. Rather, EAPL may simply be obtaining a share of the Ricardian rents associated with gas supply from Moomba." (Page 15)*

NECG define the difference between monopoly rents and Ricardian rents in the following manner.

> *"Rents from market power involve price-setting behaviour; Ricardian rents accrue to inframarginal low-cost sources of supply independently of any power over price."* (Page 16)

NECG go on to argue that because there are no efficiency implications associated with particular allocations of Ricardian rents then evidence that the MSP is sharing in these rents is not a rationale for any public policy response.

[7] For example, see section 5 of our original report.

2.4.2. NERA response

There are two significant problems with the line of argument advanced by NECG. Firstly, even if it were true that by pricing above efficient costs the MSP is simply transferring Ricardian rents from gas producers to itself, this transfer is still being achieved by the exercise of market power. The first of the above quotes from NECG is inconsistent with the second. If MSP's gathers rents by pricing above cost then those rents accrue from "price-setting behaviour" not from "inframarginal low cost sources of supply". As a result, NECG's own definition suggests any rents to the MSP are due to exercise of monopoly power.

Secondly, in order for all monopoly rents garnered by the MSP pricing above cost to be simply the transfer of what would otherwise have been Ricardian rents to gas producers it is necessary that reductions in profitability of upstream gas producers would have no long run effect on extraction and exploration activity. We find such a claim extreme and note that no evidence is provided to support it.

2.5. EGP is Efficient Bypass

2.5.1. NECG position

NECG argues that the EGP is efficient bypass of the MSP due to the fact that it provides redundancy benefits and inter-basin competition benefits.

2.5.2. NERA response

NECG provides no evidence to support its assertions in this regard. We note that in the presence of the Interconnect (which provided the redundancy benefits that NECG discuss in relation to the Longford plant crisis) the redundancy benefits of the EGP are of doubtful magnitude.

With regards to inter-basin competition, this is not a rationale for bypass under the HNE test. That is, a hypothetical coalition of consumers would not contract to build the EGP in addition to the MSP in order to provide inter-basin competition. This is because the hypothetical coalition of consumers could simply negotiate directly with gas fields using the threat of bypass to deliver the full benefits of inter-basin competition.

In any event, even if the EGP did have benefits associated with inter-basin competition and redundancy they can not be used to explain the EGP's entry. This is because such benefits are in the nature of 'public goods' for which the EGP is unable to charge.[8] Rather, as noted

[8] That is, once the benefits exist they are automatically available to all consumers at zero cost (in economic jargon they are non excludable and non rivalrous in consumption). This creates the standard economic problem of free-riding, with consumers unwilling to individually finance the creation of a new pipeline, even if such benefits warranted it, because each consumer will receive the benefits even if they do not pay.

above in section 2.1.2, if the Moomba/MSP is truly an efficient gas field/pipeline combination the EGP would only be privately profitable if the owners of the EGP expected the price of delivered gas to continue to include monopoly rents following the introduction of the EGP. This fact militates against the likelihood of any significant benefits to consumers in the form of inter-basin competition. Certainly, NECG provides no evidence of such benefits.

2.6. Regulatory Contract Approach

NECG argue that:

> *"In any case, a full implementation of the regulatory compact concept as described in the NERA report would require consideration of the pattern of over or under-recoveries over the life so far of the MSP. The ACCC's Draft Decision on the MSP Access Arrangement presents a calculation of past recoveries on the MSP from its construction in 1977 to its privatisation in 1994.[9] The ACCC's own calculation shows that tariffs on the MSP over every year of that period were so low that the implied depreciation charge was negative. The regulatory compact approach described by NERA would require capitalisation of these past under-recoveries. The ACCC's calculation shows that this approach would lead to an economic value of the MSP in 1994 of $1.29b.[10] It seems clear that the regulatory compact approach described by NERA would justify tariffs which significantly over-recover current costs in order to compensate for past under-recoveries which approach $1b on the ACCC's own numbers."* (Page 5)

2.6.1. NERA's response

NECG is incorrect when it implicitly states that NERA's definition of the regulatory contract *"would require consideration of the pattern of over or under-recoveries over the life so far of the MSP"*. NECG appear to be implying that NERA states that a regulatory contract can only come into existence at the start of an asset's life. This is not a view stated nor held by NERA - as is amply evidenced by the fact that we countenance in Section 6.3 of our September report the possibility that the Gas Code, which was enacted some 20 years after construction of the MSP, is an appropriate regulatory contract.

NERA also notes that an alternative interpretation of the regulatory contract would be that a regulatory contract came into existence with the sale of the MSP in 1994. Such a view would be supported by the recent WA Supreme Court Epic gas pipeline decision, which emphasises the legitimate business interest of the facility owner in recovering the outlays incurred in procuring the asset. In this regard we note that the MSP was procured by its current owners in 1994 for $539m. In our view, and in light of the Epic court decision, this figure of $539m is a much more realistic candidate for the opening 1994 asset value of a

9 ACCC Draft Decision on MSP Access Arrangement, Table 2.7, p. 37.

10 *This asset value is $1b more than the opening asset value in 1977 of $227m.*

regulatory contract than the $1.29b figure quoted by NECG. The 'fair' price under such a regulatory contract would certainly be less than the price calculated by NERA under the HNE test.

APPENDIX A. NECG'S REFERENCES TO THE ACADEMIC LITERATURE

NECG refer to a number of academic references that NECG claim support its argument. However, NECG tends to simply assert that these articles support its argument rather than explaining in any detail how this is the case. We find that this is simply not the case and in many cases the specific articles referred to support NERA's analysis.

A.1. Hotelling Competition

NECG argue that NERA has invoked the application of "Chadwick-Demsetz" competition 'for the market' but that:

> *"It is more plausible, and at least analytically tractable, to treat rivalry between the basins as involving Hotelling competition.*[11] *This is the conventional approach to modelling competition in which suppliers are differentiated by location – for example, as in suppliers transporting goods in a linear city, with free entry subject to a fixed set-up cost and then marginal costs that depend on distance. In this type of competition, no supplier will charge a price in excess of average cost – in other words, no monopoly profits are being earned. However, NERA's assumption that the entirety of the market will go to a single supplier will not hold."* (Page 14)

In response we make a number of points. First, it is important to note that the hypothetical new entrant test does not attempt to explain actual behaviour. The purpose of the hypothetical new entrant test is to determine a hypothetical price based on hypothetically competitive supply[12] – not to explain monopolistic behaviour, as did the original Hotelling analysis. This means that even if Hotelling competition did explain the behaviour of gas basins it would still be of no or limited relevance to the application of the hypothetical new entrant test.

Second, we consider that Hotelling competition is a remarkably poor analytical framework within which to describe any inter-basin rivalry that may exist. Hotelling competition (and the closely associated analytical models developed by Lancaster and Chamberlain) models the behaviour of firms in the provision of product diversity to customers. Hotelling competition has nothing to say about the behaviour of firms supplying goods which final customers consider homogeneous. In fact, Hotelling wrote his seminal 1929 article[13]

11 More careful analysis would seek to account for cost of extraction at the wellhead and for the value attached to redundancy. Other forms of effective competition where normal profits are earned (for example, monopolistic competition) are also more suitable than NERA's approach, though, less *a propos* than Hotelling competition.

12 In any event, NERA does not assume that the entirety of the market will go to a single supplier. Section 2.4.4 of our September report explains why it is likely that the EGP was profitable (although not efficient) and hence why it is not surprising that the market is shared between 2 firms.

13 Hotelling, H., *Stability in Competition*, The Economic Journal, March 1929.

precisely as a critique of the too common assumption that final consumers perceived all firms outputs as identical and therefore businesses could only compete with each other on price terms.

> *After the work of the late Professor F. Y. Edgeworth one may doubt that anything further can be said on the theory of competition among a small number of entrepreneurs. However, one important feature of actual business seems until recently to have escaped scrutiny. This is the fact that of all the purchasers of a commodity, some buy from one seller, some from another, in spite of moderate differences in price… A profound difference in the nature of the stability of a competitive situation results from this fact.*[14]

Hotelling goes on to postulate a model based on consumers incurring travelling costs to purchase an item from a particular firm with those costs depending on the relative location of each consumer to each firm in a linear city (as described by NECG in the above quote). Thus, while each firm's output is physically homogeneous the fact that the consumer must incur travelling costs makes them perceive the output as non-homogeneous. Hotelling effectively asks the question "will firms locate in positions along a line that minimise average travelling distances and maximise economic efficiency"? In this regard, 'travelling' distances between firms is a proxy for the diversity of product attributes between firms outputs – such as the sweetness of cider etc. Hotelling finds that under certain conditions he considers reasonable there will be too little product diversity provided by profit maximising firms.

> *"It leads some factories to make cheap shoes for the poor and others to make expensive shoes for the rich, but all the shoes are too much alike. Our cities become uneconomically large and the business districts within them are too concentrated. Methodist and Presbyterian churches are too much alike; cider is too homogeneous."* (Page 57)

We can see little relevance of Hotelling competition to explaining inter-basin rivalry. Indeed, Hotelling competition absolutely rules out the possibility that consumers located at the same point (eg, consumers serviced by delivered gas at the Wilton gates) would choose to purchase output from two different firms. Hotelling's framework is based on the assumption that firms have a degree of monopoly power over customers whose preferences are located closest to them on a linear product diversity scale and can raise price without losing all of their customers.

By contrast, delivered gas at a particular point is arguably as close to a perfectly homogeneous product in consumers' perceptions as exists. If two or more basins deliver gas to the same point then there is little they can do to differentiate their products - other than by price. This renders the theoretical framework developed by Hotelling (which is aimed at explaining how firms will differentiate their products in non price terms) almost singularly unhelpful in explaining inter-basin rivalry.

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[14] Ibid, page 41.

With this in mind we are perplexed by NECG's statement:

> *"Having said that, Hotelling competition is a realistic and well understood form of competitive discipline in cases where location is an issue. Moreover, it is more obviously applicable to an industry in which sunk costs are substantial and wellhead and customer location are largely determined exogenously. As a means of modelling hypothetical entry, it is more appropriate than that proposed by NERA."* (Page 14)

In this regard we note that:

- location is ***not*** an issue in inter basin rivalry – gas basins can not compete with each other by shifting their location closer to customers (as a cider producer can compete with another cider producer by changing the sweetness of their product);

- the very fact that basin and customer locations are exogenously set (and that delivered gas is homogeneous) means that Hotelling competition is **not** a useful framework to model inter-basin rivalry; and

- as stated above, the hypothetical new entrant test is not, and should not, be intended to replicate actual (uncompetitive) outcomes.

A.2. Competition and Cost Increases

NECG argues that NERA is "simply incorrect" in arguing that competition never gives rise to cost increases:

> *"Hotelling competition is clearly not perfect competition. There may indeed be excess entry, as each entrant firm does not take account of the impact of its entry on the fixed costs of other firms. (In this context, NERA's claim that competition never gives rise to cost increases in equilibrium is simply incorrect, as economists have known for many years – see Mankiw, N. Gregory and Whinston, Michael (1986) "Free entry and social inefficiency", Rand Journal of Economics, 17, Spring, 48-58)."*

The first point to note is that NECG is incorrect in attributing to us a claim that "competition never gives rise to cost increases in equilibrium". We can only assume that NECG is referring to our statement that:

> *"the entry of the EGP as a 'competing' pipeline cannot by itself result in the hypothetical new entrant price rising, ie, competition does not cause the competitive price to rise."* (Page 24)

Our statement is very clearly different to the statement NECG attributes to us. It is indeed well known that competition can increase *costs* but it is certainly not the case that competition increases *prices* – as per our statement. A new entrant may well increase the costs of incumbent firms in a market but new entry is only ever attracted by the existence of above normal profits. Any increase in *costs* due to new entry will not be passed on to customers in the form of higher *prices* but will rather be absorbed in the form of lower profits for incumbents (and will generally also result in lower prices in an attempt to retain market share).

Indeed, we find the paper quoted by NECG to be highly useful in supporting the analysis undertaken in our paper. Mankiw and Whinston focus on situations where entry by one firm result in a loss of market share for another firm, they call this effect the 'business-stealing effect':

> *"The business-stealing effect exists where the equilibrium strategic response of existing firms to new entry results in their having a lower volume of sales – that is when a new entrant "steals business" from incumbent firms… Intuitively, it would seem that most markets would be characterised by such an effect. As we shall demonstrate, in the presence of imperfect competition (so that firms do not act as price takers after entry), the business stealing effect is a critical determinant of the direction of entry bias.*
>
> *After formally specifying our model in Section 2, we begin our analysis in Section 3 by considering a homogeneous product market. Ignoring the integer constraint on the number of firms (as has been done in most of the previous literature), we demonstrate that if the post-entry price exceeds marginal cost and if a business-stealing effect exists, then free entry leads to excessive entry from a social standpoint (Proposition 1). Intuitively, business stealing by a marginal entrant drives a wedge between the entrant's evaluation of the desirability of his entry and the planner's: the marginal entrant's contribution to social surplus is (except for second order effects) equal to his profits less the social value of the output lost owing to the output restriction he engenders in other firms. The business-stealing effect therefore makes entry more attractive than is socially warranted."* (Page 49)

Put simply, NECG reference a paper that directly supports section 2.4.4 of our original paper which explained why the entry of the EGP pipeline may be privately profitable but not economically efficient. It is the premise of our original report that a firm can only maintain normal profit levels in the face of inefficient entry resulting in 'business-stealing' if that firm can exercise market power.

A.3. Monopoly Power

In section 4.1 of its paper NECG appear to infer that NERA's application of a hypothetical new entrant test based on a comparison of HNE prices with MSP prices is inconsistent with the literature. NECG claim the approach is "novel" and is:

> *"…inconsistent with the evidence the ACCC has led in a number of proceedings (including for example the section 46 proceedings involving parallel importation of CDs),*

acceptance by the ACCC of this test would clearly be a matter of significant importance to the public, as would any endorsement of this test by the NCC." Page 12

NECG also seem to infer that NERA's description of the HNE test is flawed and is inconsistent with the academic literature because it allows for the possibility that a firm may be exercising monopoly power but not earning monopoly profits.

"While it is obviously the case that a monopolist can incur losses (if aggregate demand falls below the level required for cost-coverage), it would be unusual for a net income test to be used to diagnose monopoly power in the way NERA suggests. Rather, net-income based tests for monopoly power generally involve a comparison of the aggregate revenues of the firm with its aggregate economic costs so as to determine whether the rate of return on its assets durably exceeds the competitive cost of capital. It is this comparison that NERA says is irrelevant." (Page 12).

In contrast to NECG's assertions it is NECG's position that is conflict with the academic literature. There is no reason why the exercise of monopoly power must give rise to above normal profits on sunk assets. (For example, a patent owner can be expected to act as a monopolist and restrict supply to maximise net revenues. However, whether those net revenues are sufficient to return a profit on sunk research and development costs is a moot point.) In fact, any test for the exercise of monopoly power, such as that proposed by NECG on page 12, that *does not* allow for the possibility of the exercise of monopoly power resulting in a lower than normal return on sunk costs is fundamentally flawed and at odds with the economic literature.

The fact that monopoly profits do not always translate to monopoly prices is well documented, including in the paper by Mankiw and Wilson[15] quoted from above (and which NECG itself invokes to support its own arguments in section 4.3 of the NECG report). In that paper Mankiw and Wilson show that monopoly pricing is consistent with firms not earning monopoly profits. This is because under a range of conditions, inefficient bypass will occur such that monopoly prices are offset by inefficiently high unit costs. In the words of Mankiw and Wilson:

"…firms enter until all the collusive monopoly profits are dissipated into set-up costs. The welfare losses caused by free entry in this example are similar to those Posner (1975) describes in his discussion of competition for monopoly positions. In both cases rent-seeking turns monopoly profits into deadweight losses." (Page 53)

So rather than our description of market power without above normal profits being 'novel' it is in fact deeply embedded in the economic literature – even in the literature that NECG quotes.

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[15] Mankiw, N. Gregory and Whinston, Michael (1986) "Free entry and social inefficiency", *Rand Journal of Economics*, 17, Spring, 48-58).

NECG have also conspicuously failed to address the fact that its own test, which compares HNE revenues with MSP revenues, would have calculated that the MSP was charging prices around 42 percent above competitive levels in 1999 (prior to the introduction of the EGP).[16] Since the introduction of the EGP, MSP prices have only fallen around 7 percent – leaving current prices still well above NECG's own implied estimate of 1999 competitive levels. By not addressing this issue NECG fails to explain why its test of monopoly power has the competitive benchmark increasing upwards of 30 percent with the entry of a new "competitor" in the form of the EGP?

16 For example, see section 5 of our September report.