Final Decision

East Australian Pipeline Limited
Access arrangement
for the Moomba to Sydney Pipeline System

2 October 2003

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Abbreviations and glossary

ABARE	Australian Bureau of Agriculture and Resource Economics
ABDP	Amadeus Basin to Darwin Pipeline
ABS	Australian Bureau of Statistics
access arrangement	an arrangement for third party access to a pipeline provided by a service provider and approved by the relevant regulator in accordance with the Code
access arrangement information	information provided by a service provider to the relevant regulator pursuant to section 2 of the Code
access arrangement period	the period from when an access arrangement or revisions to an access arrangement takes effect (by virtue of a decision pursuant to section 2 of the Code) until the next revisions commencement date
ACCC	Australian Competition and Consumer Commission
ACG	The Allen Consulting Group
ACT	Australian Capital Territory
AGA	Australian Gas Association
Agility	Agility Management Pty Ltd
AGL	Australian Gas Light Company and AGL Energy Sales and Marketing
AGLGN	AGL Gas Networks Ltd
AGLP	AGL Pipelines (NSW) Pty Ltd
AGLWG	AGL Wholesale Gas Limited
AGSM	Australian Graduate School of Management
ANAO	Australian National Audit Office
APT	Australian Pipeline Trust
CAPM	Capital Asset Pricing Model
CWP	Central West Pipeline
Code	National Third Party Access Code for Natural Gas Pipeline Systems
Commission	Australian Competition and Consumer Commission
CPI	Consumer Price Index
DAC	Depreciated actual cost
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DEI	Duke Energy International, Duke Eastern Gas Pipeline Pty Ltd and

	Duke Australian Operations Pty Ltd (collectively)
DORC	Depreciated optimised replacement cost
DRC	Depreciated replacement cost
DRP	*Draft Statement of Principles for the Regulation of Transmission Revenues,* 27 May 1999
EAPL	East Australian Pipeline Limited
EGP	Eastern Gas Pipeline
EMRF	Energy Markets Reform Forum
Epic Decision	*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231*
ESC	Victorian Essential Services Commission
EUAA	Energy Users Association of Australia
ExxonMobil	ExxonMobil Gas Marketing
FRC	Full Retail Contestability
GJ	Gigajoules (1 000 000 000 joules)
GTA	Gas Transportation Agreement
GST	Goods and Services Tax
GTD	Gas Transportation Deed
ICB	Initial capital base
IPART	NSW Independent Pricing and Regulatory Authority
IRR	Internal rate of return
km	Kilometre
KPI	Key performance indicator
MAPS	Moomba to Adelaide Pipeline System
MDQ	Maximum daily quantity
MEU	NSW Ministry of Energy and Utilities
MHQ	Maximum hourly quantity
MMA	McLennan Magasanik Associates
MSP	Moomba to Sydney Pipeline System
MSPSS Act	Moomba-Sydney Pipeline System Sales Act 1994
MW	Megawatt
NCC	National Competition Council
NECG	Network Economics Consulting Group
NEMMCO	National Electricity Market Management Company
NERA	National Economic Research Associates

NGAC	New South Wales Greenhouse Abatement Certificate
NPV	Net present value
O&M	Operating and maintenance
OffGAR	Office of Gas Access Regulation (Western Australia)
ORC	Optimised replacement cost
ORG	Office of the Regulator-General, Victoria (now the Victorian Essential Services Commission)
Origin	Origin Energy Pipelines Pty Ltd
PIAC	Public Interest Advocacy Centre
PJ	Petajoules (equal to 1 000 000 Gigajoules)
PMA	Pipeline Management Agreement
prospective user	a person who seeks or who is reasonably likely to seek to enter into a contract for a service (including a user who seeks or may seek to enter into a contract for an additional service)
reference service	a service which is specified in an access arrangement and in respect of which a reference tariff has been determined
reference tariff	a tariff specified in an access arrangement as corresponding to a reference service
reference tariff policy	a policy describing the principles that are to be used to determine a reference tariff
service provider	a person who is the owner or operator of the whole or any part of the pipeline or proposed pipeline
SIB	Stay in business
SKM	Sinclair, Knight Mertz Pty Ltd
SOO	Statement of Opportunities
TJ	Terajoule (equal to 1 000 Gigajoules)
TPA	The Pipeline Authority
WACC	Weighted Average Cost of Capital

Executive Summary

Background

On 5 May 1999, East Australian Pipeline Limited (EAPL) submitted a proposed access arrangement and access arrangement information for the Moomba to Sydney Pipeline System (MSP) which extends from Moomba (South Australia) to Wilton (Sydney, NSW) and includes laterals to Canberra and regional centres including Lithgow and Griffith.[1] Approval was sought from the Australian Competition and Consumer Commission (the Commission) under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code).

An access arrangement and access arrangement information describe the terms and conditions on which the company will make access to its pipeline available to third parties. The Commission's assessment of this original access arrangement and access arrangement information involved public consultation and an examination of information provided by both EAPL and interested parties. The Commission released its *Draft Decision* in December 2000 in which it proposed, in accordance with section 2.13(b) of the Code, not to approve the access arrangement in its current form. The Commission put forward a number of amendments that would have to be made in order for the access arrangement to be approved.

Since the release of the *Draft Decision* there have been a number of events that have delayed the Commission's assessment process, most notably:

- EAPL's application to the National Competition Council (NCC) for revocation of coverage on the Moomba to Wilton and Canberra lateral segments of the MSP;
- the large number of changes proposed by EAPL following the change in ownership;
- the WA Court of Appeal's ruling on the Dampier to Bunbury pipeline access arrangement[2] (the Epic Decision), following which EAPL submitted further revisions to the proposed value of the initial capital base (ICB); and
- the announcement by AGL that it had entered into a new portfolio of gas supply contracts, following which EAPL submitted revisions to the proposed capital expenditure and volumes forecast to be transported on the MSP.

In addition to these events, the delay in the assessment process can be partially attributed to EAPL's inability to meet deadlines and information requests made by the Commission.

After considering EAPL's proposals and submissions by interested parties, the Commission has decided, pursuant to section 2.16(b)(ii) of the Code, not to approve the revised access arrangement proposed by EAPL. This *Final Decision* sets out the

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1 The ownership of EAPL was transferred to the Australian Pipeline Trust in June 2000. For consistency, all references to the service provider made throughout this document will be to EAPL as the applicant.

2 *Re: Dr Ken Michael AM; ex parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231*, 23 August 2002.

amendments (or nature of the amendments) which are required in order for the Commission to approve EAPL's revised access arrangement. These vary in some instances from those proposed in the *Draft Decision*, primarily as a result of consideration by the Commission of submissions by EAPL and other interested parties.

EAPL is required to submit a revised access arrangement that complies, to the Commission's satisfaction, with this *Final Decision* by 23 October 2003. The Commission will then assess the revised access arrangement and release a *Final Approval* (section 2.19 of the Code). If EAPL fails to submit an amended revised access arrangement, or submits an amended access arrangement that does not comply with the *Final Decision*, then the Commission must draft and approve its own access arrangement (section 2.20 of the Code).

The table below compares a number of key access arrangement elements proposed by EAPL with those approved by the Commission. Following this is a brief outline of the key issues arising within the *Final Decision*.

***Final Decision* at a glance**

Elements	EAPL's proposal	Commission's Final Decision
DORC	$972m Based on the NPV of the first 'n' years' cash flows of a new entrant in a hypothetically contestable market where 'n' is the remaining life of the existing asset.	$715m Based on 'straight line depreciation' methodology for deriving DORC from ORC.
ICB	$779m Based on EAPL's 'reasonable expectations under the prior regulatory regime'. Represents the NPV of EAPL's cash flows at 1998.	$559m ORC written down on basis of a 50 year asset life, the depreciation rate assumed by EAPL in the past.
New facilities investment	Includes a proposed back-up compressor on the Northern lateral at an estimated cost of $4m.	The Commission considers that EAPL's forecast capital expenditure is reasonably likely to meet the test under section 8.16 of the Code.
Depreciation	-$14.4 m (real) over the access arrangement period. Economic depreciation used which produces a back-end loaded depreciation schedule and negative depreciation during the first access arrangement period.	$60.6m (real) over the access arrangement period. The Commission considers that negative depreciation in real terms for the MSP is inappropriate. Differences in the parameters used for the value of the ICB, rate of return and non capital costs result in differences in the assumed depreciation.
Rate of return	EAPL proposed a post-tax nominal return on equity of 14.8% and a pre-tax real WACC of 7.9%.	Applying the Commission's standard post-tax nominal framework, the Commission considers that a nominal post-tax return on equity of 11.3% and a nominal vanilla WACC of 8.2% best meets the Code requirements.
Non capital costs	EAPL proposed non capital costs of approximately $23m (real $2001/02) per annum over 2004-2008.	The Commission considers these costs to be in excess of what would be incurred by a prudent service provider acting efficiently. Specifically, the Commission considers that two fees payable to Agility and Petronas would not have been incurred by a prudent service provider acting efficiently and has proposed that forecast operating costs be reduced by the forecast value of these two components.

Forecast volumes	In May 2003 EAPL proposed a significant reduction in forecast volumes (to those previously submitted) with average volumes of 92.9 PJ pa over the access arrangement period.	The Commission has approved average volumes of 93.4 PJ pa. The Commission has broadly accepted EAPL's forecasts with a minor upwards adjustment to the base year volumes.
Tariff methodology, tariff path and forecast revenue	NPV methodology. Price path approach to setting tariffs using the CPI-X mechanism. X factor of 0.33% for the mainline. X factor of -4% for the laterals. Average nominal revenue of \$80.86 m per year over the access arrangement period. Average tariff of \$0.71/GJ on Moomba to Sydney segment over the same period.	NPV methodology Price path approach to setting tariffs using the CPI-X mechanism. X factor of 1.60% for the mainline. X factor of 0.38% for the laterals. Average nominal revenue of \$68.1m per year over the access arrangement period. Average tariff of \$0.53/GJ on Moomba to Sydney segment over the same period. (Because of EAPL's existing contractual arrangements with AGL in which AGL is required to make minimum monthly payments to EAPL irrespective of the level of reference tariffs, EAPL's actual revenue will be considerably higher in the short term than that approved by the
Cost allocation and tariff setting	EAPL proposed allocating costs between two pipeline systems: the mainline and regional laterals. Only one reference tariff was proposed, and this tariff was divided into a capacity and throughput charge.	The *Final Decision* accepts the approach proposed by EAPL.
Incentive structure and pass through	EAPL proposed a pass through mechanism for taxes as well as costs associated with full retail contestability. A simple 'P_0' incentive mechanism was also submitted – EAPL retains any gains from outperforming its forecasts in the current period, but no carryover mechanism was proposed.	The Commission has largely accepted EAPL's proposed pass through mechanism, however, it has only allowed EAPL to recover certain costs associated with tax changes and full retail contestability. The Commission has also accepted EAPL's proposed incentive mechanism, however, the Commission notes EAPL's limited opportunity to reduce its operating costs because of its contractual arrangements with Agility and Petronas.
Services policy	EAPL's services policy consists of a Firm Service (the Reference Service) and a Negotiable Service.	The Commission accepts that the proposed services policy satisfies the requirements of the Code.
Extensions and expansions policy	Apart from addressing the requirements of section 3.16 EAPL also proposed a method by which acquired covered and uncovered pipeline assets should be treated. In addition, EAPL proposed that some flexibility be incorporated into the extensions and expansions policy to allow the Interconnect to be viewed as an extension to the covered pipeline unless the relevant Minister decides to revoke coverage.	The Commission considers that the proposal to incorporate into the capital base acquired covered and uncovered pipelines does not adequately address the new facilities investment tests in the Code and requires this provision to be removed. As to the treatment of the Interconnect, the Commission considers that the Code does not allow for such flexibility on issues of coverage. For the purposes of the *Final Decision* the Interconnect will be viewed as part of the covered pipeline.
Review and expiry	EAPL proposed to submit revisions to the access arrangement 5 years after its commencement. EAPL also proposed that that be a 7 month review period.	The Commission considers that the access arrangement period should be 5 years in duration and that there should be a 12 month access arrangement review period.

Key Issues

Reference tariff methodology, tariffs and revenue

EAPL has proposed the use of the Net Present Value (NPV) methodology applied on a real pre-tax basis to determine its total revenue requirement over the expected life of the MSP. EAPL has also proposed the use of price path approach to varying tariffs using the Consumer Price Index – X (CPI-X) mechanism to establish the path of tariffs over the remainder of the economic life of the pipeline. The NPV framework differs from the traditional cost of service approach in a number of ways. First, total revenue is simply the product of forecast volumes and the proposed tariff path. Second, depreciation is the amount left after deducting capital costs and non capital costs from total revenue (termed economic depreciation) such that where there is an under recovery of these factors the extent of under recovery is added to the capital base. Conversely, where there is an over recovery of these factors the difference is subtracted from the capital base. Finally, the X factor in the NPV framework is the value which produces a tariff path (and total revenue) that results in the asset base reducing to zero by 2056.

Using the NPV methodology and its assumed values for the ICB, capital costs, non capital costs and volumes EAPL has proposed an X factor of 0.33 per cent on the mainline and an X factor of -4 per cent on the regional laterals with tariffs commencing at their current published levels. These price paths produces average revenue of $90.86 million (nominal) per annum over the period 2004-2006 and an average tariff of $0.71 per GJ on the Moomba to Sydney segment of the pipeline.

As the NPV and the price path methodologies are set out in the Code the Commission has no objection to their use. The Commission does, however, have concerns with the individual parameters proposed by EAPL and has adopted different values for the ICB, rate of return, non capital costs and volumes. Using the Commission's proposed parameters the X factor derived using the NPV approach is 1.60 per cent for the mainline with an initial fall in tariffs of 21 per cent. On the regional laterals the X factor generated using the Commission's proposed parameters is 0.38 per cent with no initial fall in tariffs. This price path produces average revenue of $68.1 million (nominal) per annum over the period 2004-2006 and an average tariff of $0.53 per GJ on the Moomba to Sydney segment of the pipeline.

The Commission is aware of the existence of the Gas Transportation Deed (GTD) between EAPL and AGL Wholesale Gas (AGLWG). While this existing contractual agreement has not been taken into account when assessing the proposed tariffs, the Commission notes that the agreement in effect provides EAPL with a shelter from the Commission's decisions affecting revenue through to the beginning of 2007.

The principal differences between the Commission's proposed parameter values and those proposed by EAPL are briefly outlined below.

Initial capital base

EAPL proposed a value for the ICB of $779 million, based upon what it contends were its *'reasonable expectations under the prior regulatory regime'*. According to EAPL these reasonable expectations were formed in 1997/98 and the value of these expectations can be estimated using the NPV of its expected future cash flows at that time.

The Commission has assessed the $779 million ICB value proposed by EAPL in accordance with section 8.10(g) which states that consideration should be given to the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code. The Commission does not, however, consider that EAPL has sufficiently demonstrated that an ICB of $779 million is underpinned by the previous regulatory regime, or that it forms part of the 1994 sale agreement with the Australian Government. Accordingly, the Commission does not consider that EAPL's proposal satisfies the criteria in section 8.10(g) of the Code.

For the purposes of the *Final Decision* the Commission considers that the appropriate value for the ICB is $559.3 million. This valuation is based on the optimised replacement cost (ORC) of the assets, which the Commission has, over the period 1976 to 2000, depreciated on the basis of a 50 year asset life (the life assumed in the past by EAPL for depreciation purposes). Future depreciation charges, however, are based on an 80 year asset life, which EAPL submitted is now the useful life of the MSP and which the Commission has accepted. In determining the value for the ICB, the Commission has placed significant weight on section 8.10(f) of the Code which provides for consideration to be given to the basis on which tariffs have been (or appear to have been) set in the past, economic depreciation and historical returns.

The Commission did not consider it appropriate to revalue the asset base upwards as a result of the variation to the useful life from 50 to 80 years. Revaluations upwards as a result of extensions to the useful life of an asset would result in the asset owner more than recovering its efficient costs over the life of the asset.

New facilities investment

EAPL's proposed capital expenditure over the access arrangement period includes the construction of a back-up compressor on the Northern Lateral to avoid what EAPL considers to be potential peak system constraints.

The Commission considers that projected demand for the Northern Lateral supports the current need for compression at Young during the peak winter season. Given the dependency on compression, the Commission considers that it would be prudent for EAPL to improve the reliability of compression on the Northern Lateral by installing a back-up unit at Young. The Commission therefore considers that EAPL's forecast capital expenditure is reasonably likely to meet the new facilities tests contained in the Code.

Depreciation schedule

In keeping with the NPV methodology to setting tariffs, EAPL has proposed an economic depreciation approach, in which depreciation charges change in a manner consistent with the growth in the market. Under this approach depreciation charges change in line with projected volumes which according to EAPL are expected to fall in the short term before subsequently rising over the medium to longer term. In effect this produces a back end loaded depreciation profile. As a result of the price path assumed by EAPL over the access arrangement period, EAPL has proposed economic depreciation charges of -$14.4 million (real). According to EAPL the negative allowance reflects an under recovery of capital and non capital costs.

While the Commission accepts EAPL's economic depreciation methodology in principle, it does not accept that negative depreciation in real terms is appropriate for the MSP for the initial access arrangement period. EAPL's negative depreciation schedule is a function of its high proposed costs (notably the value for the ICB) coupled with its proposed price path, which has EAPL's current published tariffs as its starting point. This would produce an under recovery of EAPL's proposed costs in the short term, which is rolled into the asset base and results in an increase in the value of the asset base over the access arrangement period.

Such an approach may be appropriate, for example, for new pipelines with low levels of initial volumes and which anticipate market growth. The Commission does not consider, however, that negative depreciation is appropriate for the MSP, given its level of maturity and current and future throughput profiles. The depreciation charges approved by the Commission for each year of the access arrangement period will differ to those proposed by EAPL to reflect differences in the value of the ICB, rate of return, non capital costs and net tax allowances approved by the Commission in this *Final Decision*.

Rate of return

EAPL has proposed a nominal post-tax return on equity of 14.8 per cent and a nominal return on debt of 7.3 per cent. The Commission does not, however, consider that these values would result in a return which is commensurate with prevailing conditions in the market for funds and the risks involved in delivering the reference service. The Commission is of the view that a better estimate of the nominal post-tax return on equity is 11.3 per cent. Similarly, the Commission considers that a value of 6.2 per cent reflects a better estimate of the nominal cost of debt. Combining these values with a 60:40 gearing level yields a nominal vanilla WACC of 8.2 per cent.

The Commission notes the three principal differences between EAPL's proposal and the Commission's estimation are the equity beta, risk free rate and debt margin. In terms of the 1.45 equity beta proposed by EAPL, the Commission considers that this exaggerates the systematic risks faced by a regulated natural gas transmission service provider and that a value of one (the market average) would be more appropriate. While the Commission accepts that EAPL faces a number of specific risks which have the potential to affect forecast volumes, consistency with the Capital Asset Pricing Model (CAPM) framework suggests that such risks should not be compensated by a high equity beta but rather through cash flows where the risks can be identified and estimated. The Commission notes that allowance for the risks cited by EAPL has been made through the downwardly revised volume forecasts.

In relation to EAPL's proposed use of a 10 year risk free rate the Commission has maintained its approach of matching the bond rate with the length of the access arrangement period (which in this case is five years). Lastly the Commission notes that since the release of the *Draft Decision*, the Commission has adopted an empirical approach to estimating the debt margin which utilises data from capital markets. This data suggests that the debt margin applicable to a five year term is currently around 92 basis points compared to the 120 basis points proposed by EAPL.

Apart from the specific differences set out above, the financial market related parameters relied upon by EAPL has not been updated since the submission of the revised access arrangement in May 2002. Since that time the risk free rate and inflation expectations have fallen. These changes in market conditions are reflected in the Commission's analysis.

Non capital costs

EAPL has forecast non capital costs of approximately $23 million per annum in real terms ($2001/02) over the period 2004-2008. These costs are almost double the costs originally proposed by EAPL and approved by the Commission in the *Draft Decision*. EAPL has sought to justify the upwardly revised costs by stating that the revised costs reflect the change in ownership and operation of the MSP resulting from the formation of APT by AGL. EAPL has also attributed the rise to the increase in insurance premiums and the disposal of various assets used in operation of the pipeline.

The Commission notes APT's decision to outsource the majority of the day to day operation of its pipelines to its affiliates – Petronas and Agility Management Pty Ltd (a subsidiary of AGL). Two cost components arising from this outsourcing that were of particular concern to the Commission were the management fee payable to Agility and a marketing fee payable to Petronas. The Commission considers that these costs would not have been incurred by a prudent service provider acting efficiently and considers that forecast operating costs should be reduced by the forecast value of these two cost components.

Forecast volumes

Following AGL's announcement regarding its new portfolio of gas supply contracts, EAPL submitted revised volume forecasts. In view of the magnitude of the downward revisions, the Commission engaged an external consultant to prepare independent forecasts and to provide a critique of the assumptions and methodology underpinning EAPL's revised forecasts. The results of this analysis suggested that if an adjustment of 2 to 4 PJ was made to the 2001/02 base year estimate of total NSW and ACT demand, then EAPL's forecasts for this aspect of demand and in turn its projections for forecast flows on the MSP would be plausible.

Overall, the Commission considers that a 2.36 PJ adjustment should be made to the base year estimate of NSW and ACT gas demand. This adjustment amounts to an average increase in EAPL's proposed volumes of approximately 0.54 PJ per annum over the access arrangement period and overall result in average volumes to be transported on the MSP of 93.4 PJ per annum over the period.

Reference tariff variation policy

In its revised access arrangement, EAPL put forward a reference tariff mechanism that allows it to pass through to users any changes in taxes and full retail contestability (FRC) costs. In the *Final Decision* the Commission has accepted EAPL's proposal subject to several amendments, including that EAPL must demonstrate to the

Commission's satisfaction that it has incurred only certain costs associated with retail contestability and changes in taxes/levies.

Incentive structure

EAPL has proposed what is known as a P_0 benefit sharing mechanism. Under this approach, EAPL retains any unanticipated savings (or losses) achieved above (or below) the path of revenues through the initial access arrangement period, but no additional allowance is provided in the subsequent access arrangement period for efficiencies achieved. Whilst the Commission considers that the proposed incentive structure proposed meets the relevant Code requirements, it notes that EAPL's current significant outsourcing arrangements provide EAPL with limited opportunity to reduce its operating costs. Therefore the parties to these contractual arrangements (Agility and Petronas) are best positioned to capture any attainable efficiencies.

Cost allocation and tariff setting

EAPL has proposed allocating pipeline costs between two pipeline systems: the mainline and regional laterals. The Moomba to Wilton Pipeline, the Wagga Lateral, the Interconnect and the Canberra Lateral have been classified as part of the mainline, while the Northern Lateral and Griffith Lateral are considered to be regional laterals. Costs are allocated between these segments on the basis of ORC. EAPL also proposed one reference tariff, which is separated into a capacity charge and a throughput charge. Fixed pipeline costs are allocated to the capacity charge and variable costs are allocated to the throughput charge in the ratio 96 per cent to 4 per cent.

In the *Final Decision*, the Commission has accepted EAPL's proposal on the basis that the elements comply with the relevant provisions of the Code.

Services policy

EAPL's proposed services policy consists of both a Firm Service and a Negotiable Service. The Firm Service represents the reference service and is defined as a service which provides for the transportation of gas through any part of the pipeline in any direction and in so doing provides for backhaul services. As its name suggests the Firm Service is not subject to curtailment or interruption, except as set out in the access arrangement or the transportation agreement.

The Commission accepts that the Firm Service is one which is likely to be sought by a significant part of the market and therefore satisfies the requirements of the Code. The Commission also considers that the inclusion of the Negotiable Service provides users and prospective users with the ability to obtain only those elements it wishes to be included in the service at a negotiated tariff.

Terms and conditions

Interested parties have expressed a number of concerns with EAPL's proposed terms and conditions, in particular those terms and conditions relating to: receipt and delivery points; operational and balancing provisions; gas quality; overrun charges; daily variance charges; liabilities and indemnities; the order of priority of service; custody, control and title of gas; force majeure and capacity charge relief; assignment; insurance; and system use gas.

The Commission has examined each of the proposed terms and conditions to assess whether they are in fact reasonable taking into account the factors set out in section 2.24 of the Code. As a result of this examination, the Commission requires a number of amendments to the terms and conditions proposed.

Trading policy

EAPL's proposed trading policy provides that a user may: make a bare transfer if the transferee notifies EAPL beforehand; transfer its contracted capacity other than by way of a bare transfer with the prior written consent of EAPL; and transfer its Maximum Daily Quantity from a receipt or delivery point subject to consent from EAPL. EAPL's consent to the transfer may not be unreasonably withheld subject to the satisfaction of a number of commercial and technical criteria.

The *Draft Decision* proposed a number of amendments to the trading policy originally proposed by EAPL and these amendments have been incorporated within the revised trading policy. The Commission is satisfied that the amendments address the concerns raised in the *Draft Decision* and the revised trading policy complies with the principles set out in the Code.

Queuing policy

The Commission has accepted that EAPL's proposed 'first in first served' policy is appropriate for the MSP given the excess capacity expected to prevail over the initial access arrangement period. The Commission, however, has some concerns with the order of priority accorded to the reference and negotiable service. The *Final Decision* therefore requires an amendment to provide that the reference service and negotiated service will have equal priority in the queue subject to a prospective user seeking the reference service at the reference tariff having priority over a prospective user seeking the reference service at a tariff less than the reference tariff.

Extensions and expansions policy

The Commission has broadly accepted EAPL's proposed extensions and expansions policy, however, there are two aspects which the Commission considers need to be addressed. Specifically, the proposed treatment of acquired covered or uncovered pipelines and the proposed treatment of the Interconnect. With regard to the former the Commission considers that the provision proposed by EAPL does not adequately reflect the new facilities investment tests set out in the Code and thus in its current form is not consistent with the Code. After due consideration the Commission is of the view that there are adequate provisions within the Code to deal with the merger of two pipelines, and therefore the inclusion of this provision within the access arrangement is unnecessary.

With regard to the treatment of the Interconnect, EAPL has proposed that if its application for the revocation of coverage of the Moomba to Wilton segment and Canberra lateral is unsuccessful, then the Interconnect should be viewed as part of the covered pipeline and therefore included within its extensions and expansions policy. If, however, the application is successful, EAPL submits that the Interconnect should not be covered. In view of these alternative scenarios EAPL has requested that a flexible coverage mechanism be included within the access arrangement to provide for these possibilities.

The Commission has examined whether a flexible coverage mechanism can be incorporated. The Commission's analysis, however, suggests that the Code does not appear to provide for such flexibility as decisions relating to the revocation of coverage can only be made by the relevant minister. Ultimately the decision as to whether the Interconnect should be included within the extensions and expansions policy can only be made by EAPL. In view of the access arrangement information provided by EAPL to date which explicitly provide for the incorporation of the Interconnect (such as estimates of the ICB, forecast volumes and non capital costs) the Commission has decided for the purposes of the *Final Decision* to assume that the Interconnect forms part of the covered pipeline.

Review and expiry

EAPL has proposed to submit revisions to the access arrangement five years after the date the regulator deems that the access arrangement comes into effect. EAPL also proposes that revisions to the access arrangement commence either seven months after the revisions submission date or on the date that the regulator approves the revised access arrangement.

After taking into account the length of time it would take for the Commission to assess any revisions, the proposed duration of the initial access arrangement exceeds five years. The Commission does not consider in this instance that an access arrangement period in excess of five years is appropriate given that the five year period has formed the basis for the selection of a number of financial parameters. Furthermore, the Commission considers that in view of the time it has taken to assess the revised access arrangement a longer assessment period is required to minimise the risk that the access arrangement period will extend significantly beyond five years. Accordingly, the *Final Decision* provides for an amendment to the access arrangement which requires EAPL to submit revisions four years after the current access arrangement comes into effect.

Key performance indicators

EAPL put forward two key performance indicators (KPI) in its revised access arrangement, that is operating costs as a per cent of ORC and operating costs per thousand kilometres of pipeline. EAPL stated that under both these measures its performance is within the range accepted by regulators.

The Commission acknowledges the limitations of KPI measures and the debate surrounding the relevance of different benchmarks. The Commission, however, considers that a variety of KPIs can help develop a better understanding of the costs proposed by EAPL. Accordingly, in the *Final Decision* the indicators proposed by EAPL in its initial access arrangement have been re-calculated by the Commission with reference to Australian transmission pipeline data. In addition, the Commission has used non capital costs (less compressor maintenance and fuel gas costs) per km per PJ as a KPI.

The KPIs calculated by the Commission generate mixed results. In terms of total expenses, EAPL's revised costs exhibit the fourth highest costs on a per kilometre basis relative to comparator pipelines. EAPL exhibits the third highest total costs per kilometre net of depreciation and the fourth highest costs in terms of total expenses per km per PJ.

With regard to operating costs, EAPL sits at the low end of the range in terms of general and administrative costs per km per PJ (which include overheads and marketing expenses). However, EAPL performs poorly with regard to operating and maintenance costs (which broadly constitutes pipeline and compressor maintenance costs) exhibiting the highest total operating costs per km relative to other pipelines. EAPL also performs below average when total operating costs per km are compared and exhibits higher costs than comparable pipelines in terms of non capital costs on a volume-distance basis.

1. Introduction

On 5 May 1999, East Australian Pipeline Limited (EAPL) submitted a proposed access arrangement and access arrangement information for the Moomba to Sydney Pipeline System (MSP) to the Australian Competition and Consumer Commission (the Commission).[3] Approval was sought under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code). The MSP extends from Moomba (South Australia) to Wilton (Sydney, NSW) and includes laterals to regional centres including Lithgow and Griffith.

The Commission released its *Draft Decision* on EAPL's proposed initial access arrangement on 19 December 2000. It proposed not to approve the access arrangement in its current form. The Commission identified a number of amendments to the proposed access arrangement that would need to be satisfactorily incorporated in a revised access arrangement in order for it to be approved (pursuant to section 2.13(b) of the Code).

In June 2001, EAPL applied to the National Competition Council (NCC) for partial revocation of coverage of the MSP under the Code. At the same time, EAPL requested that the Commission delay the release of its *Final Decision* on the access arrangement pending the NCC's *Final Recommendation* in relation to the revocation of coverage issue. The Commission agreed to EAPL's request subject to a six month review.

At the review of this decision in January 2002, the Commission received a further request from EAPL to postpone the *Final Decision*. After careful consideration of the request the Commission decided it would not be in the public interest to delay the assessment process further. This was based on the fact that the *Draft Decision* was 12 months old and the NCC had made a *Draft Recommendation* not to revoke coverage based on the Commission's findings in the *Draft Decision*.

EAPL had previously advised the Commission (on 14 March 2001) of its concerns with the original access arrangement (submitted prior to APT's acquisition of EAPL) and foreshadowed its intention to submit a revised access arrangement. When the Commission recommenced the assessment process a deadline of 28 February 2002 was initially set for the submission of the revised access arrangement. This was later extended to 30 April 2002 at EAPL's request.

The revised access arrangement was submitted on 30 April 2002, however it lacked sufficient access arrangement information to conduct the public consultation process as required under the Code. Following numerous requests for additional information and EAPL's revisions to forecast volumes, capital expenditure and the value of the ICB the Commission decided in May 2003 to request a consolidated access arrangement information document. This was submitted on 7 July 2003.

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3 The ownership of EAPL was transferred to the Australian Pipeline Trust in June 2000. For consistency, all references to the service provider made throughout this document will be to EAPL as the applicant.

The access arrangement and access arrangement information describe the terms and conditions on which the company will make access to its pipeline available to third parties. The Commission's assessment of the revised access arrangement (of May 2002) is being conducted in accordance with the requirements set out in the Code and is based on information and comments provided by EAPL and interested parties.

This document sets out the Commission's *Final Decision* and related proposed amendments under section 2.16 of the Code for EAPL's revised access arrangement.

The remainder of this introduction includes:

- a description of the regulatory framework;
- an outline of the MSP and coverage issues;
- an outline of the MSP revised access arrangement submitted for approval;
- a description of the NSW gas industry structure;
- a description of the MSP;
- a description of the current assessment process;
- an outline of the criteria for assessing an access arrangement;
- an overview of the information provided by EAPL;
- an outline of the consultative process; and
- the Commission's *Final Decision*.

Chapter 2 of this *Final Decision* considers major issues associated with the regulatory rate of return and the initial capital base (ICB) valuation which are required to determine reference tariffs for third party access. The reference tariff principles in section 8 of the Code are also examined.

Chapter 3 provides an assessment of the revised access arrangements in terms of the non-tariff mandatory elements in the Code.

Chapter 4 examines performance indicators.

Chapter 5 sets out the Commission's *Final Decision*. The Commission has identified the amendments that would need to be made to the revised access arrangement in order for it to be approved. These proposed amendments are set out in the relevant sections of the *Final Decision* and are brought together in this chapter.

1.1 Regulatory framework

The main legislation and relevant documents regulating access to gas transmission pipelines in NSW are:

- the Code, under which transmission service providers are required to submit access arrangements to the Commission for approval;

- the *Gas Pipelines Access (South Australia) Act 1997*;[4] and
- the *Gas Pipelines Access (New South Wales) Act 1998*.[5]

Code and appeal bodies in NSW with respect to transmission pipelines are:

- the Commission – regulator and arbitrator;
- the National Competition Council – Code advisory body;
- the Commonwealth Minister – coverage decision maker;
- the Federal Court – judicial review; and
- the Australian Competition Tribunal – administrative appeal.

The Independent Pricing and Regulatory Tribunal (IPART) is the regulator for gas distribution systems in NSW and the Independent Competition and Regulatory Commission (ICRC) is the regulator for the gas distribution system in ACT, Queanbeyan and Yarralumla Shires.

1.1.1 Coverage under the Code

All of the pipelines included in the MSP are covered under the Code with the exception of the EAPL owned portion of the Interconnect (that extends from Wagga Wagga to Culcairn). For the purpose of the *Final Decision* the Interconnect has been treated as an extension to the covered pipeline and therefore included as part of this access arrangement.

EAPL has lodged applications with the NCC on two separate occasions for the revocation of coverage of various parts of the MSP. The first, submitted on 28 April 2000, requested coverage be revoked for the MSP mainline and two lateral pipelines under the Code.

In its *Final Recommendation* to the Minister on 8 September 2000, the NCC concluded that coverage of the Moomba to Wilton pipeline, the Young to Culcairn pipeline and the Dalton to Canberra pipeline should not be revoked. The Minister for Industry, Science and Resources, Senator The Hon. Nick Minchin, released his decision on 16 October 2000 in support of the NCC's recommendation.

In June 2001, EAPL lodged a second application for revocation with the NCC on the basis that the Australian Competition Tribunal's decision regarding coverage on the EGP provided support for revocation of the MSP.[6] On this occasion EAPL requested the NCC consider the revocation of coverage on the Moomba to Wilton pipeline and the Canberra lateral.

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4 South Australia acted as lead legislator for the national gas access legislation.

5 NSW subsequently enacted legislation applying the SA legislation in NSW. The NSW legislation commenced on 14 August 1998.

6 *Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2*, 4 May 2001.

On 14 November 2002, the NCC forwarded its *Final Recommendation* that coverage of the pipelines not be revoked to The Hon. Ian Macfarlane MP, Minister for Industry, Tourism and Resources. The Minister is currently considering the recommendation.

1.2 Structure of the gas industry in NSW

Briefly, the overall structure of the gas industry in NSW has the following key characteristics:

- the total volume of natural gas consumed (including gas used in electricity generation) in NSW was 136.3 PJ in 2000-2001;[7]
- the MSP transports gas from Moomba to the Sydney city gate at Wilton, with laterals and spur lines to Canberra and regional centres including Lithgow, Yass and Wagga Wagga;
- the Eastern Gas Pipeline (EGP), a transmission pipeline from Longford (Victoria) to Horsley Park (NSW), was commissioned in September 2000 to supply Gippsland Basin gas into NSW;
- prior to the commencement of the EGP, almost all of the natural gas demand in NSW were supplied solely by the Cooper Basin Production Unit in South Australia, which has supplied natural gas to NSW since 1976;
- AGL Gas Networks Limited (AGLGN) operates the natural gas distribution system in Sydney and most regional centres in NSW, including Newcastle and Wollongong;
- Envestra Ltd operates the natural gas distribution system in Albury, and Country Energy Gas Networks distribute natural gas in Wagga Wagga;
- under the NSW Government's timetable for the introduction of competition in the NSW retail gas market all gas customers became contestable on 1 January 2002; and
- the Interconnect, a pipeline between Barnawartha (Victoria) and Wagga Wagga (NSW), was completed in August 1998 linking the NSW and Victorian natural gas systems.[8] This was initially the only link between the NSW and Victorian gas pipeline systems and now provides an alternative supply route for Gippsland Basin gas into NSW since the commencement of the EGP.

1.2.1 The MSP

The MSP was built in the mid 1970s to supply Sydney with gas from the Cooper Basin. It extends from Moomba in South Australia to Wilton on the outskirts of Sydney, where it connects with AGLGN's distribution networks. The Moomba to Wilton pipeline is 1299 km in length with a diameter of 864 mm and has compressors located at Bulla Park and Young to augment capacity. Mainline offtakes are located at Marsden, Young and Dalton.

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[7] ABARE, *Australian Energy: National and State projections to 2019-2020*, June 2003, p. 78.

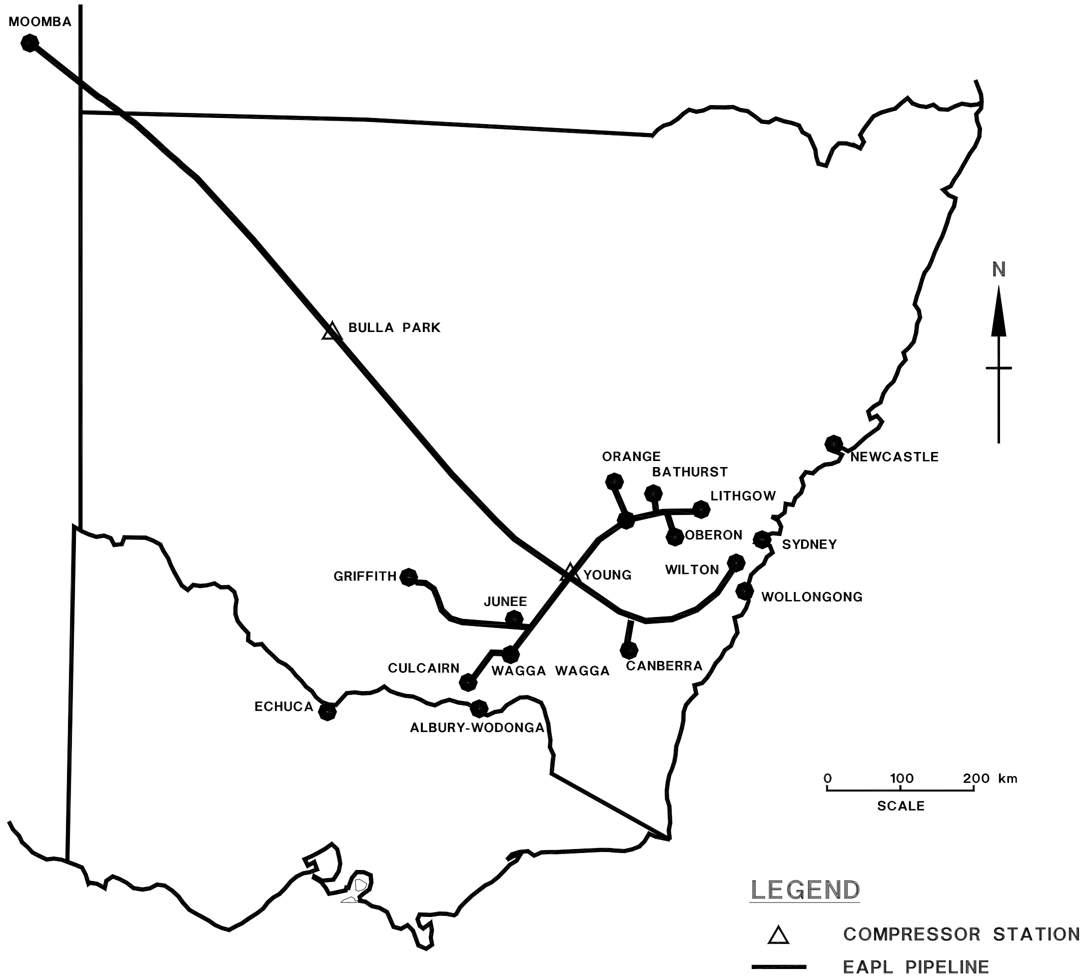
[8] EAPL owns the Interconnect section extending between Wagga Wagga and Culcairn, GasNet owns the remainder (Culcairn to Barnawartha, Victoria).

The MSP also includes the following pipelines:

- Young to Wagga Wagga: commissioned in 1981 (131 km in length);
- Dalton to Canberra: commissioned in 1981 (58 km in length);
- Young to Lithgow: commissioned in 1987 (270 km in length);
- Junee to Griffith: commissioned in 1993 (179 km in length);
- Wagga Wagga to Culcairn: commissioned in 1998 (88 km in length).

The location of the MSP is illustrated in Figure 1.2.1.1 below.

Figure 1.2.1.1: Geographic location of the MSP



Source: EAPL access arrangement information, 7 July 2003, p. 23.

For tariff setting purposes, EAPL has segregated the MSP into two pipeline groups. These are the:

- Mainline: Moomba to Young, Young to Wilton, Young to Culcairn; Dalton to Canberra; and
- Laterals: Young to Lithgow with spur lines to Bathurst, Cootamundra, Oberon and Orange (Northern lateral), and Junee to Griffith (Griffith lateral).

The service provider

Section 2 of the Code specifies that the service provider is required to submit a proposed access arrangement (and associated access arrangement information) to the regulator for approval. The service provider is defined as 'a person who owns (whether legally or equitably) or operates the whole or any part of a Pipeline'. EAPL currently owns the MSP. The access arrangement provides for ownership of the MSP to change over time.[9] The Commission expects that it will receive notification of any change in ownership or operation of the MSP should any changes occur in the future.

EAPL purchased the MSP from The Pipeline Authority (TPA), an Australian Government owned entity, in June 1994. At the time, and until December 1999, EAPL was owned by AGL (51 per cent) and Gasinvest Australia Pty Ltd (49 per cent).[10] Maintenance and operational activities of the pipeline were carried out by EAPL Operations Pty Limited while marketing activities were conducted by East Australian Pipeline Marketing Pty Limited. These companies were owned by AGL and Gasinvest Australia.

AGL increased its interest in EAPL to 76 per cent in December 1999 through its acquisition of shares held by TransCanada Pipelines Limited. AGL's ownership of the MSP (and other transmission pipelines wholly or partly owned by AGL) was subsequently transferred to the Australian Pipeline Trust (APT) when the company was floated in June 2000. While 60 per cent of shares in APT are now held by the general public, AGL (with 30 per cent ownership) is the largest single investor and Petronas now has a 10 per cent interest in the company.

Historical background to the MSP

The MSP was initially proposed by AGL in the early 1970s following the discovery of natural gas in the Cooper Basin. The Australian Government established the TPA as part of a plan to facilitate the establishment of an interconnected national gas pipeline system and assumed control of the project in 1974. TPA subsequently transported gas on behalf of AGL consistent with the contractual commitments AGL had already entered into with the Cooper Basin producers.

As part of its long term restructuring of the Australian economy in the 1980s, the Australian Government embarked on a broad range of micro and macro economic reforms, including a National Gas Strategy in November 1991. The sale of the MSP

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9 EAPL access arrangement, 5 May 1999, p. 50.

10 Gasinvest Australia was jointly owned by the TransCanada Pipelines Limited (formally NOVA Gas Australia Pty Ltd) and Malaysian owned Petronas Australia Pty Ltd.

was part of this strategy. The *Interstate Gas Pipelines Bill* introduced in 1993 was designed to establish an appropriate regulatory environment following the sale of the pipeline. More specifically, the regulatory framework was designed to promote the development of a competitive pipeline industry structure by providing, among other things, for open access to third parties.

The *Moomba-Sydney Pipeline System Sale Act 1994* (MSPSS Act) enabled the sale of the MSP to EAPL. The sale of the pipeline system and related assets to EAPL for $534 million was completed on 30 June 1994.[11]

Under the provisions of the MSPSS Act the Commission's predecessors (the Trade Practices Commission and the Prices Surveillance Authority) had regulatory responsibility regarding third party access disputes and the monitoring of haulage charges and transactions that were not conducted at arm's length.

The legislative framework underpinning the MSPSS Act was seen as a temporary measure pending the implementation of the current uniform framework applying to third party access to gas transmission pipelines and distribution networks in Australia under the Code.

Gas Transportation Agreement

Between 30 June 1994 and 30 June 2000, AGL Wholesale Gas Limited (AGLWG) acquired most of its haulage services through the MSP under the Gas Transportation Agreement (GTA) with EAPL. These rights were preserved under the MSPSS Act. Under the GTA, the terms and conditions for the transmission haulage of gas were established between EAPL and AGLWG to supply customers in NSW and ACT. The terms and conditions of this agreement were separate to those established for third party access under the MSPSS Act. Although the GTA was scheduled to conclude on 31 December 2016, it was terminated and replaced by the GTD between AGLWG and EAPL on 30 June 2000.

The GTD is a framework agreement setting out the broad relationship between EAPL and AGLWG until 31 December 2016. Haulage services provided to AGLWG are in accordance with the minimum published reference tariffs[12] for comparable haulage services under this access arrangement.

The GTD also specifies a minimum level of monthly payments that AGLWG must make to EAPL until 1 January 2007. AGLWG is entitled to deduct from these payments the tariffs payable by AGLWG for services provided in that period. However, if, at 1 January 2007, the amounts AGLWG is entitled to deduct are less than the total of the payments, EAPL will retain the difference. That is, the payments would be non-refundable.

On 4 January 2000, the Commission received an application from EAPL seeking approval for the GTD with AGLWG as an associate contract under section 7.1 of the

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11 The Pipeline Authority, *1993-94 Annual Report*, pp. 30-31.

12 These tariff charges may be varied in certain events as defined in the GTD.

Code. The Commission approved the revised GTD as submitted by EAPL on 3 April 2000.[13]

1.2.2 The Interconnect

The Interconnect, which was completed in July 1998, is a 151 km pipeline of 450 mm diameter linking the NSW and Victorian pipeline systems. EAPL owns the 88 km northern section (from Wagga Wagga to Culcairn) while GasNet Pty Ltd owns the 62 km southern section (from Barnawartha (near Wodonga) to Culcairn).

The Interconnect is able to provide northern or southern gas flows thereby enabling customers in both NSW and Victoria to potentially enjoy alternative supplies of gas. Following the Longford processing plant explosion in 1998, the capacity of the Interconnect to deliver gas into Victoria was increased from 35TJ/day to 92TJ/day.[14]

In April 2000, the Commission approved an application by GasNet to include the capital cost and associated operations and maintenance costs of its portion of the Interconnect (and associated compressor and valves) to the Victorian Principal Transmission System access arrangement.[15] EAPL has sought to include its portion of the Interconnect in this revised access arrangement, should its application for revocation currently before the Minister not be approved.[16]

1.2.3 Eastern Gas Pipeline

The EGP is owned by Duke Eastern Gas Pipeline Pty Ltd, DEI Eastern Gas Pipeline Pty Ltd and Duke Australia Operations Pty Ltd (collectively known as DEI). The 792 km pipeline extends between Longford (Victoria) and Horsley Park (NSW). The pipeline provides an alternative source of gas for consumers in Sydney as well as providing the possibility for natural gas supply for the first time to towns on the eastern seaboard of Australia south of Wollongong.

The EGP was completed on 17 August 2000 and had an initial capacity of 55 PJ of gas per year, which is equal to approximately half the current NSW gas demand that had been supplied by the MSP. Since this time the capacity of the EGP has been expanded to 65 PJ and DEI has proposed to install additional compressors to the pipeline to match demand growth up to a maximum capacity of 110 PJ per annum.

On 7 January 2000, AGL Energy Sales and Marketing Ltd lodged an application with the NCC for coverage of the EGP under the Code. On 3 July 2000 the NCC released its *Final Recommendation* in which it recommended coverage of the whole pipeline.

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[13] ACCC, *Statement of reasons for decision: East Australian Pipeline Limited proposed Gas Transportation Deed*, 3 March 2000.

[14] ACCC, *Final Decision*: *GasNet application for revision*, p. 21.

[15] ACCC, *Final Decision*: *Access arrangement for the Principal Transmission System, application for revision by GPU GasNet Pty Ltd,* 28 April 2000.

[16] EAPL letter to the Commission, 15 August 2003.

On 16 October 2000, the Minister for Industry, Science and Resources, Senator The Hon. Nick Minchin, accepted the NCC's recommendation and announced that the EGP would be a covered pipeline for the purposes of the Code. On 27 October 2000, DEI filed an Application for Review of the decision for coverage of the EGP with the Australian Competition Tribunal (Tribunal).

On 4 May 2001, the Tribunal overturned the Minister's decision and ordered that the EGP should not be covered.[17] The basis for the Tribunal's decision was that the EGP did not have market power to hinder competition due to the countervailing power of other market participants, the existence of spare pipeline capacity and the competition it faced from the MSP and the Interconnect. The Tribunal concluded that coverage would not promote competition in either upstream or downstream markets.

1.3 The assessment process

The revised access arrangement and access arrangement information dated May 2002 and July 2003 respectively describe the terms and conditions on which EAPL will make access to the MSP available to third parties during the initial access arrangement period which EAPL proposes will last approximately five years. However, under the provisions of the Code, EAPL has the discretion to submit revisions earlier than the scheduled review.

While the Commission's current assessment process relates to the initial access arrangement period it will also impact on subsequent access arrangement periods.

Section 2 of the Code sets out the assessment process to be undertaken by the Commission which involves the following:

- Inform interested parties that it has received the access arrangement and access arrangement information from EAPL;
- Publish a notice in a national daily newspaper which describes the covered pipeline to which the access arrangement relates and states how copies of the documents may be obtained. A date by which submissions are to be lodged must also be specified in the notice;
- After considering submissions received, issue a draft decision which proposes either to approve the access arrangement or not to approve the access arrangement and state the amendments (or nature of the amendments) which have to be made to the access arrangement in order for the Commission to approve it. Submissions are sought again following the release of the Commission's draft decision;
- After considering any additional submissions and a revised access arrangement (if submitted), issue a *Final Decision* that either approves or does not approve the access arrangement (or revised access arrangement) and states the amendments (or nature of the amendments) which have to be made to the access arrangement (or revised access arrangement) in order for the Commission to approve it; and

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17 *Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2*, 4 May 2001.

- If the amendments are satisfactorily incorporated in a revised access arrangement, issue a final approval. If not, the Commission must draft and approve its own access arrangement.

1.4 Criteria for assessing an access arrangement

The Commission may approve a proposed access arrangement only if it is satisfied that it contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code, which are summarised below. An access arrangement cannot be rejected by a regulator solely on the basis that it does not address a matter that section 3 of the Code does not require it to address. Subject to this, the Commission has a broad discretion in accepting or opposing an access arrangement.

An access arrangement must include a policy on the service (or services) to be offered which includes a description of the service(s) to be offered. The policy must include one or more services that are likely to be sought by a significant part of the market and any service(s), which in the Commission's opinion should be included in the policy. To the extent practicable and reasonable, users and prospective users must be able to obtain those portions of the service(s) that they require, and the policy must allow for a separate tariff for an element of a service if requested.

An access arrangement must also contain one or more reference tariffs. A reference tariff operates as a benchmark tariff for a particular service and provides users with a right of access to the specific service at the specific tariff. Tariffs must be determined according to the reference tariff principles in section 8 of the Code.

An access arrangement must also include the following elements:

- a services policy which must include a description of one or more services that the service provider will offer to users and prospective users;
- one or more reference tariffs and a reference tariff policy with tariffs determined according to the reference tariff principles in section 8 of the Code;
- the terms and conditions on which the service provider will supply each reference service;
- a statement of whether a contract carriage or market carriage capacity management policy is applicable;
- a trading policy that enables a user to trade its right to obtain a service (on a contract carriage pipeline) to another person;
- a queuing policy to determine users' priorities in obtaining access to spare and developable capacity on a pipeline;
- an extensions and expansions policy to determine the treatment of extensions and expansions of a pipeline under the Code;
- a date by which revisions to the arrangement must be submitted; and
- a date by which the revisions are intended to commence.

In considering whether an access arrangement complies with the Code, the Commission must (pursuant to section 2.24 of the Code) take into account:

- the legitimate business interests and investment of the service provider (section 2.24(a));
- firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline (section 2.24(b));
- the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline (section 2.24(c));
- the economically efficient operation of the covered pipeline (section 2.24(d));
- the public interest, including the public interest in having competition in markets (whether or not in Australia) (section 2.24(e));
- the interests of users and prospective users (section 2.24(f)); and
- any other matters that the Commission considers are relevant (section 2.24(g)).

The WA Court of Appeal handed down its decision on the 23 August 2002 in relation to the matter of *Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002]* (the Epic Decision). This decision is the only legal precedent currently available which addresses the interpretation of the Code and its supporting legislation. Accordingly, in reaching its *Final Decision,* the Commission has considered carefully the implications of the Epic Decision.

Briefly the Epic Decision followed the release of the Draft Decision by the Independent Gas Pipelines Access Regulator WA (WA Regulator) for the access arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP). In that decision the WA Regulator proposed an ICB of approximately $1.234 billion.[18] This contrasted with Epic's proposed ICB of $2.407 billion. Based on its findings, the WA Regulator proposed reference tariffs of $0.74 and $0.85 per GJ. Epic subsequently sought judicial review of the Draft Decision. As such a review is confined to errors of law, Epic's application was referred directly to the Court of Appeal where the matter was considered.

The Epic Decision focused primarily on the appropriate approach to adopt when setting the ICB for a pipeline. The Court of Appeal concluded that the WA Regulator's Draft Decision was affected by error. While the Court of Appeal did not quash the Draft Decision, it did indicate an expectation that the WA Regulator would apply the Court's decision in making its Final Decision.

In the course of its judgement the Court of Appeal also made a number of findings regarding the meaning and operation of various provisions of the Code. These findings provide valuable guidance in the interpretation of the Code that is directly relevant to the current assessment process. In particular, the Court of Appeal found that the factors in section 2.24 of the Code are relevant to the whole of the access arrangement,

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18 While the National Code applies in WA, the Office of Gas Access Regulation (OffGAR) is the relevant regulator.

including reference tariffs and the reference tariff policy. In determining reference tariffs and reference tariff policy, the regulator should apply the objectives in section 8.1, but should be guided by section 2.24 where the section 8.1 objectives conflict or give the regulator discretion. A regulator must also consider each of the factors specified in section 2.24 as fundamental elements.

1.5 Information provision

In addition to submitting a proposed access arrangement a service provider is required, pursuant to section 2.2 of the Code, to submit access arrangement information. This must contain sufficient information to enable users and prospective users to understand the derivation of the elements in the proposed access arrangement and to form an opinion as to the compliance of the access arrangement with the provisions of the Code (section 2.6). The access arrangement information may include any relevant information, but must at least contain the information described in Attachment A to the Code (section 2.7) (see Appendix A of this *Final Decision*).

Information included in the access arrangement information may be categorised or aggregated to the extent necessary to ensure that disclosure of the information is not, in the opinion of the relevant regulator, unduly harmful to the legitimate business interests of the service provider, users or prospective users (section 2.8).

If the regulator is not satisfied that the access arrangement information meets the requirements of the Code, it may, of its own volition, require the service provider to make changes to the access arrangement information. Similarly, if requested to do so by any person, the regulator must review the adequacy of the access arrangement information. However, the regulator must not require access arrangement information to be released which, in the regulator's opinion, could be unduly harmful to the legitimate business interests of the service provider or a user or prospective user (section 2.9).

If the regulator requires the service provider to change the access arrangement information, it must specify the reasons for its decision and allow the service provider a reasonable amount of time to make the changes and resubmit the access arrangement information.

Original access arrangement information provision

In addition to the original access arrangement submitted on 5 May 1999 EAPL submitted access arrangement information.[19] In response to this the Commission released an issues paper on the proposed access arrangement on 4 June 1999. Following ongoing discussions with the Commission, EAPL agreed to make additional information public. On 28 October 1999, EAPL voluntarily released supplementary access arrangement information.[20] In addition to this, EAPL submitted further information to the Commission and noted that the information was commercially sensitive given the presence of the EGP in the NSW market.

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[19] EAPL access arrangement information, 5 May 1999.

[20] EAPL supplementary access arrangement information, 28 October 1999.

In August 2000, EAPL submitted an alternative proposal for determining the value of the depreciated optimised replacement cost (DORC).[21] This approach differed considerably from the more traditional approach of calculating DORC on the basis of straight line depreciation.

In September 2000, following the public float of APT, EAPL expressed concern with the access arrangement initially proposed and submitted several revisions to the access arrangement.[22] EAPL's proposed revisions were considered in the *Draft Decision* to enable interested parties to comment on the relevant issues.

Revised access arrangement information provision[23]

On 14 March 2001, EAPL submitted its response to the *Draft Decision*. In this response EAPL noted its intention to lodge with the Commission a revised access arrangement reflecting 'agreed' amendments from the *Draft Decision* as well as other matters previously advised. The assessment process was then postponed for six months following a request by EAPL that the Commission delay its consideration until the NCC concluded its assessment of whether coverage should be revoked on the Moomba to Wilton pipeline and Canberra lateral. Following the release of the NCC's *Draft Recommendation* in which the NCC recommended that coverage not be revoked the Commission requested that EAPL submit a revised access arrangement by 28 February 2002.

In a letter dated 19 February 2002, EAPL again requested the Commission defer its *Final Decision* or alternatively provide it with an extension to submit its revised access arrangement by 28 June 2002. The Commission agreed to an extension although only to 31 March 2002. The Commission subsequently extended the submission date to the end of April 2002 at the request of EAPL.

EAPL submitted a revised access arrangement on 30 April 2002. A three page document summarising the provisions of the revised access arrangement was submitted by EAPL on 3 May 2002. This attachment incorporated a number of tables setting out total operating expenditure, total capital expenditure, the proposed rate of return, depreciation, forecast throughput and the valuation of the ICB.

On 27 May 2002, the Commission requested that additional information be made public to enable informed discussion by interested parties. On 20 June 2002, EAPL submitted the further information which included: an explanation of the underlying methodology and justification of the value of the ICB; estimates of the DORC and ORC for each pipeline and asset class; a brief justification for each rate of return parameter; a brief description of forecast capital expenditure; an explanation of the depreciation approach proposed; and a brief justification for the increase in non capital cost forecasts over the access arrangement period. On the same day the Commission

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21 Agility Management, *The Construction of DORC from ORC,* August 2000.

22 EAPL response to the Commission, 21 September 2000.

23 Details of the documents referred to in this section are provided in Appendix D of this *Final Decision*.

released a second issues paper on the proposed access arrangement and invited submissions from interested parties.

In November 2002, the Commission asked EAPL to submit a non confidential consolidated information document setting out its responses to the various requests by the Commission for further information. A draft copy of this consolidated information document was provided on 21 December 2002 and a final version was received on 8 April 2003.

EAPL's submissions following the Epic Decision

On 5 November 2002, EAPL lodged a submission with the Commission in which it contended that in light of the Epic Decision, the Commission's *Draft Decision* for the MSP was fundamentally flawed, particularly in relation to the setting of the ICB. EAPL contended that the *Draft Decision* should be set aside and the Commission prepare a new *Draft Decision*. At the same time, EAPL submitted further upward revisions to the value of the ICB from the $667 million submitted in May 1999 and the $740 million submitted in April 2002 to a value of $768-$972 million based on what it claimed were its 'reasonable expectations under the prior regulatory regime'. EAPL also submitted proposed changes to the balancing arrangements.

On 11 November 2002, the Commission released its third issues paper and invited comments from interested parties with respect to EAPL's contentions regarding the value of the ICB and the proposed changes to the balancing arrangements.

On 4 December 2002, EAPL submitted further revisions to the value of the ICB with the revised value ranging from $779-$998 million.

EAPL's submissions following the AGL announcement

On 30 January 2003, EAPL foreshadowed that it would be submitting revisions to the forecast volumes, capital expenditure and operating expenditure previously supplied in May 2002. This, EAPL advised, was necessary given the announcement by AGL on 18 December 2002 that it had negotiated a new portfolio of gas supply arrangements which would result in a lower commitment to the MSP. Following this the Commission wrote to EAPL requesting the submission of revised volume forecasts by 7 March 2003.

On 7 March 2003, EAPL submitted preliminary volume forecasts to the Commission. In a letter accompanying the forecasts, EAPL stated that the AGL announcement had brought to the fore the difficulties in estimating the market share of both the MSP and the EGP.[24] According to EAPL, these difficulties along with changes in the likely sources of supply and changes to State and Australian Government policies regarding greenhouse gas emissions made it essential to totally review gas throughput forecasts.[25] At a meeting on 24 March 2003, EAPL advised the Commission that it intended to engage a consultant (ACIL Tasman) to review its revised volume forecasts and that the review would take up to six weeks. The Commission agreed to this process and at the

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[24] EAPL letter to the Commission, 7 March 2003.

[25] EAPL revised access arrangement information, 7 July 2003, p. 36.

same time requested additional information on the proposed non capital costs. The information regarding non capital costs was submitted on 15 April 2003.

On 12 May 2003, EAPL submitted a confidential version of the ACIL Tasman review and revised volume forecasts. These forecasts, which extend to 2022, represent a 35 per cent downward revision to the forecasts submitted in May 2002 and have resulted in a corresponding increase in the proposed tariffs. Along with the downward revisions to forecast volumes EAPL revised the timing of its proposed capital expenditure. This information was submitted to the Commission on 16 May 2003.

On 26 May 2003, the Commission asked EAPL to submit revised access arrangement information by 10 June 2003. In requesting this information the Commission was mindful that the last comprehensive access arrangement information had been submitted in May 1999 and that since that time EAPL had proposed fundamental changes to a number of different aspects of the original proposed access arrangement. In that letter the Commission also requested revised tariff models and further information on non capital costs, the proposed tariff path and forecast capital expenditure. EAPL agreed to the provision of this information in a letter to the Commission on 3 June 2003, but stated that the deadline could not be met. At the request of the Commission, EAPL provided its responses to the Commission's additional questions on 10 June 2003 and submitted confidential tariff models on 12 June 2003.

On 20 June 2003, EAPL advised the Commission that it would not be in a position to submit the revised access arrangement information until at least 7 July 2003. The Commission responded to this request on 25 June by informing EAPL that it was not satisfied that the information provided by it to date had met the requirements of sections 2.6 and 2.7 of the Code. As a result of the deficiencies, the Commission required EAPL to submit revised access arrangement information pursuant to section 2.9 of the Code.

In a letter dated 1 July 2003, EAPL advised the Commission that it would submit its revised access arrangement information by the requested deadline, but that due to resource constraints additional volume related information sought by the Commission would not be provided until one week after that date. On 4 July 2003, the Commission agreed to allow EAPL to submit the volume related information on 14 July 2003.

On 7 July 2003, EAPL submitted both a public and confidential version of the revised access arrangement information. According to EAPL this information replaced any previous, proposed or revised access arrangement information documents submitted by it.[26] The access arrangement information provided detailed information on the proposed: access and pricing principles; reference tariff structure; the asset base; economic lives of assets; capital expenditure; rate of return; non capital costs; total revenue; proposed tariff variation methodology; system capacity; volume assumptions; and performance measures.

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[26] EAPL revised access arrangement information, 7 July 2003, p. 3.

On 9 July 2003, EAPL informed the Commission that it would be able to submit some additional information regarding the revised volumes by 14 July 2003, but that a public version of the ACIL Tasman volumes report would not be available until 16 July 2003. The Commission responded on 11 July 2003, agreeing that it would not release its own public version of the ACIL Tasman report before 17 July 2003. Additional volume related information was received by the Commission on 14 July 2003 and EAPL provided a public version of the ACIL Tasman volumes report on 16 July 2003. An issues paper on forecast volumes, the fourth completed by the Commission during this review process, was released on 17 July 2003.

Appendix D contains a summary of the information provided by EAPL to the Commission and the requests made by the Commission for this information.

Conclusion

Over two years has lapsed between EAPL's announcement of its intention to lodge a revised access arrangement (March 2001) and its submission of revised access arrangement information (July 2003). This extensive delay to the Commission's assessment process is the product of a number of different factors, most notably:

- EAPL's application to the NCC for revocation of coverage on the Moomba to Wilton and Canberra lateral segments of the MSP;
- the large number of changes proposed by EAPL following the change in ownership;
- the Epic Decision, following which EAPL submitted further revisions to the proposed value of ICB; and
- the announcement by AGL that it had entered into a new portfolio of gas supply contracts, following which EAPL submitted revisions to the proposed capital expenditure and volumes forecast to be transported on the MSP.

In addition to these events, the delay in the assessment process can be partially attributed to EAPL's inability to meet deadlines and information requests made by the Commission. These delays can clearly be seen in the outline provided above (and in the table at Appendix D) which demonstrates not only the piecemeal nature of the information submitted to the Commission over a 14 month period but also the number of instances in which EAPL has requested extensions to the submission dates proposed by the Commission.

On a separate but related issue, the Commission has examined EAPL's contention that the *Draft Decision* should be set aside and a new *Draft Decision* prepared. The Commission rejects these contentions and notes that EAPL has had adequate opportunities to be heard in relation to all aspects of its proposed access arrangement, including matters relating to the impact of the Epic Decision and the revised volume forecasts. The Commission is also conscious that the process in the Code provides further opportunities for EAPL to be heard in relation to any amendments contained in this *Final Decision*.

1.6 Consultative process

Pursuant to the requirements of section 2 of the Code, the Commission sought input from interested parties during the assessment process of the revised access arrangement. The Commission received written submissions from seven interested parties on its *Draft Decision* and twelve interested parties following the *Draft Decision* and the release of the proposed revised access arrangement (see Appendix B). The major issues raised by interested parties have included:

- valuation of the ICB;
- rate of return;
- depreciation;
- reference tariffs;
- operating and maintenance costs;
- terms and conditions; and
- other non-tariff elements such as the extensions and expansions policy.

During the Commission's assessment process of EAPL's revised access arrangement of May 2002, two issues have arisen that have warranted further consultation with interested parties. These are:

- the Epic Decision; and
- AGL's announcement of its intention to source some 563 PJ over 10 years from Victoria's Gippsland producers to meet its requirements in Victoria and NSW.[27]

To ensure procedural fairness the Commission has conducted separate public consultation processes with regard to the impact (if any) of these issues and proposed changes. As a part of this process, the Commission released an issues paper seeking comment from interested parties on the implications of the Epic Decision on the MSP access arrangement (11 November 2002). Submissions were received from DEI, Energy Markets Reform Forum (EMRF) and EAPL in response to this issues paper. The Commission also sought public comment on EAPL's most recent volume forecast revisions on 17 July 2003 and received submissions from AGL Energy Sales and Marketing and TXU.

1.7 Final Decision

The Commission has now made a Final Decision under section 2.16(b)(ii) of the Code not to approve the MSP access arrangement in its current form and has outlined the amendments that would be required to be made in order for the access arrangement to be approved. The revised access arrangement, incorporating the required amendments, must be submitted to the Commission by 23 October 2003.

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27 ALG media release, *AGL announces new gas supply portfolio,* 17 June 2003.

In order for the Commission to approve a revised access arrangement under section 2.19, the Commission must be satisfied that the amendments specified in this *Final Decision* have been incorporated, or that EAPL has addressed (to the Commission's satisfaction) the reasons for which the Commission required the amendments. These amendments have been set out in the relevant sections in this document and also in chapter five of the *Final Decision.*

If EAPL:

- does not submit a revised access arrangement by the required date, or
- does so and the Commission is not satisfied it has incorporated amendments specified in this *Final Decision*, or otherwise addressed to the Commission's satisfaction, the reasons for which the Commission required the amendments,

then, the Commission must draft and approve its own access arrangement (section 2.20 of the Code). Such a decision is subject to merits review by the Australian Competition Tribunal under the Gas Pipeline Access Law.

2. Reference tariff elements

Pursuant to section 2.24 of the Code, the relevant regulator may approve an access arrangement only if it is satisfied that the proposed access arrangement contains the elements set out in sections 3.1 to 3.20 of the Code and satisfies the principles within these sections.

Within the next two chapters, the reference tariff and non-tariff elements contained within EAPL's proposed access arrangement will be examined and assessed for compliance with the Code. In undertaking this assessment, the relevant sections within the Code will be outlined followed by:

- a summary of the provisions proposed by EAPL in its original access arrangement submitted in May 1999;
- a summary of the Commission's *Draft Decision*;
- an outline of submissions received in response to the Commission's *Draft Decision*;
- a summary of the provisions proposed by EAPL in its revised access arrangement submitted in April 2002 and in subsequent correspondence (such as the correspondence following the Epic Decision and the AGL announcement regarding new gas supply contracts);
- an outline of submissions received in response to EAPL's revised access arrangement and, where relevant, submissions in response to EAPL's proposals following the Epic Decision and the AGL announcement;
- the Commission's considerations, which includes, consideration of relevant section 8 provisions and where required, consideration of the factors set out in section 2.24 of the Code; and
- where relevant, amendments that the Commission proposes in order for the access arrangement to be approved.

This chapter will examine EAPL's proposed reference tariff and reference tariff policy. Commencing with an outline of the principal elements of EAPL's original and revised reference tariff policy the remainder of the chapter will document the assessment of the reference tariff methodology utilised and the various parameters used to derive total revenue and reference tariffs including:

- the ICB;
- new facilities investment;
- capital redundancy;
- depreciation;
- the rate of return;
- non capital costs;
- forecast volumes;

- forecast revenue and tariff path;
- reference tariff variation policy;
- incentive mechanisms; and
- cost allocation and tariff setting.

The chapter concludes with an overall assessment of whether EAPL's proposed reference tariff and reference tariff policy complies with the reference tariff principles described in sections 8.1 and 8.2.

Principal elements of EAPL's proposed reference tariff policy

Original access arrangement

EAPL originally proposed that the revenue requirement for the MSP be calculated using the current cost accounting methodology in which its revenue requirement was calculated using:

- A notionally rebased capital base derived by indexing the capital base for an estimate of inflation on an annual basis. The valuation method proposed by EAPL for establishing the value of the ICB was the depreciated optimised replacement cost;
- A pre-tax real rate of return of 8.4 per cent applied to the ICB;
- A 5/8:3/8 kinked depreciation schedule; and
- Forecast non capital costs.

In relation to the allocation of these costs, EAPL proposed that total costs be recovered through users of the firm transportation service and small take-off point service using a distance based two part tariff comprising a capacity charge and a throughput charge. EAPL further proposed that the MSP be divided into mainline and lateral segments with different, and higher, tariff structures applying to lateral segments.

To establish the path of tariffs to prevail on the mainline over the access arrangement period, EAPL utilised a smooth price path approach. Specifically, EAPL proposed that the published tariffs applicable at the time be the reference point for the initial year with tariffs in subsequent years determined in accordance with a Consumer Price Index-X (CPI-X mechanism). Recognising that under this approach forecast revenue over the period (as calculated by multiplying tariffs by forecast volumes) may differ from the target revenue calculated using the Cost of Service approach, EAPL set the value of X to ensure that the NPV of both measures of revenue were equal. This approach in effect equated the price path approach with the strict cost of service approach. Provision within EAPL's original access arrangement was also made for the adjustment of the price path in instances of new or increased taxes, charges, levies, imposts and fees.

The X value proposed for the mainline was 1.25 per cent for the firm transportation service. In contrast to the price path proposed for the mainline, EAPL proposed that base tariffs be set for the lateral reference tariff each year and adjusted in accordance with the change in the CPI relative to the CPI prevailing in 2000. This approach was designed to phase in higher tariffs on the laterals over the access arrangement period.

The principal incentive mechanism incorporated into EAPL's proposal was that which was implicit in the price path model, otherwise known as the P_0 incentive mechanism. That is with no adjustments made to tariffs for actual outcomes over the access arrangement period under this approach a service provider has an implicit incentive to pursue efficiencies and exceed forecast volumes.

Revised access arrangement

In contrast to the Cost of Service approach proposed in the original access arrangement, EAPL's revised access arrangement proposes the use of the NPV methodology to establish the revenue requirements of the MSP over the remaining economic life of the pipeline. [28] The revenue requirement utilising the NPV methodology has been calculated using:

- An ICB of $779 million (as at 1 July 2000) adjusted to account for new facilities investment, depreciation, redundant capital and inflation;
- A pre-tax real rate of return of 7.9 per cent;
- Economic depreciation calculated as the residual amount once operating costs and the return on assets is deducted from total revenue. The proposed depreciation profile is back-end loaded for both the mainline and laterals; and
- Forecast non capital costs.

EAPL has proposed that total costs be recovered from users of the reference service and that the MSP be segregated into mainline and lateral segments. For tariff setting purposes the mainline is defined as comprising the Moomba to Wilton Pipeline, Canberra Lateral, Wagga Lateral and the Interconnect. The lateral segments are defined as the Northern Lateral (Young to Lithgow) and the Griffith Lateral. Fixed and variable costs attributable to the mainline and lateral segments have then been used to establish the capacity and throughput tariffs applicable on each segment.

In relation to the tariff path that will prevail over the access arrangement period, EAPL has proposed the use of a price path approach designed to ensure that it recovers its forecast non capital costs, a return on investment and depreciation. Specifically, EAPL has proposed that the published tariff prevailing at the time be used as the initial tariff and that tariffs in subsequent years be adjusted in accordance with the CPI-X mechanism. Within the revised access arrangement EAPL proposed X values of 4 per cent and -4 per cent for the mainline and regional laterals respectively. Following the submission of revised gas throughput forecasts, EAPL revised the X value for the mainline to 0.33 per cent and left the lateral X value at -4 per cent. As with the original access arrangement, provision has also be made for adjustments to the tariff path in instances of any new or increased taxes, charges, levies, imposts, fees or costs associated with the introduction of full retail contestability (FRC) in NSW, ACT or

[28] EAPL revised access arrangement, 30 April 2002, p. 10.

Victoria. EAPL has deemed these events as specified events under the trigger event adjustment approach.

Under EAPL's proposed price path approach, forecast revenue over the period (calculated by multiplying tariffs by forecast volumes) may differ from the cost of providing the service. To the extent that there are differences, EAPL proposes the use of economic depreciation (defined as the difference between revenue less operating costs less a return on assets) such that where the tariff path:

- under recovers non capital costs and the rate of return, the extent of under recovery is added to the regulatory asset value (negative economic depreciation); and
- over recovers non capital costs and the rate of return, the extent of over recovery is deducted from the regulatory asset value (positive economic depreciation).

In relation to incentive mechanisms, EAPL has submitted that[29]:

- the level of reference tariff is designed to enable EAPL to develop the market for the reference service and other services in an environment of pipeline competition;
- the retainment of greater than forecast returns provides EAPL with an incentive to increase volumes and minimise the cost of providing services; and
- in developing reference tariffs for the next access arrangement period, EAPL will ensure that users and prospective users share in the benefits of increased efficiencies achieved by EAPL up to that date.

The culmination of these mechanisms, will according to EAPL encourage it to reduce total operating costs and increase pipeline throughput.

2.1 Reference tariff methodology

Within this section consideration is given to the methodology utilised by EAPL to calculate its revenue requirement and the form of regulation used to establish the tariff path over the access arrangement period. Consideration of the actual calculation of the various determinants of EAPL's revenue requirement and the mechanisms used to establish the tariff path are set out in the subsequent sections of this chapter.

2.1.1 Code requirements

Section 8.3 of the Code states that, subject to section 8.3A[30] and the regulator being satisfied that it is consistent with the objectives set out in section 8.1, the method by which the reference tariff may vary during an access arrangement period through the implementation of the reference tariff policy is within discretion of the service provider. This section of the Code provides four alternative forms of regulation

[29] EAPL revised access arrangement information, 7 July 2003, p. 6.

[30] Section 8.3A of the Code states that a reference tariff may vary within an access arrangement period only through the implementation of the approved reference tariff method as provided for in sections 8.3B to 8.3H.

methodologies (but notes that any variation or combination of these approaches may also satisfy the Code). These are:

- the Cost of Service[31] approach – where tariffs are adjusted throughout the access arrangement period to account for actual outcomes (such as sales volumes and actual costs) to ensure that the actual costs of the services are recovered;
- the Price Path approach – where tariffs are determined prior to the commencement of the access arrangement period and follow a path which is not adjusted to take account of subsequent events until the start of the next access arrangement period;
- the Reference Tariff Control Formula Approach – where tariffs may vary over the access arrangement period in accordance with a specified formula or process; and
- the Trigger Event Adjustment Approach – where a reference tariff may vary within the access arrangement period following the occurrence of a specified event.

Section 8.4 of the Code permits the use of one of three methodologies for determining the total revenue:

- Cost of Service - where total revenue is set to recover costs with those costs to be calculated on the basis of:
  - A rate of return on the value of the capital assets that form the covered pipeline where the rate of return is set to provide a return commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (sections 8.30 and 8.31 of the Code);
  - Depreciation of the capital base; and
  - The non capital costs incurred in providing all services over the covered pipeline.
- Internal Rate of Return (IRR) - where total revenue is set to provide an IRR for the covered pipeline on the basis of forecast costs and sales, subject to the principles set out in section 8.30 and 8.31 of the Code.
- Net Present Value (NPV) - where total revenue is set to deliver a NPV for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using the discount rate that would yield a return consistent with sections 8.30 and 8.31 of the Code.

Section 8.4 further provides that the methodology used to calculate total revenue may also allow the service provider to retain some or all of the benefits arising from efficiency gains under an incentive mechanism. The amount of the benefit will be determined by the regulator in the range of 0 to 100 per cent of the total efficiency gains achieved.

While these methodologies are different ways of assessing the total revenue, their outcomes should be consistent. For example, it is possible to express any NPV

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[31] This approach is distinct from the Cost of Service approach detailed in section 8.4 of the Code, which refers to the methodology used to determine total revenue.

calculation in terms of a Cost of Service calculation by the choice of an appropriate depreciation schedule. In addition, other methodologies (such as a method that provides a real rate of return on an inflation-indexed capital base) are acceptable under section 8.5 of the Code, provided they can be translated into one of these forms.

Section 8.5A provides that the above methodologies may be applied on a nominal basis, real basis or any other basis in dealing with the effects of inflation. If the methodology is applied on a real basis, the capital base, depreciation and all costs and revenues are expressed in constant prices and a real rate of return is allowed.

2.1.2 Original access arrangement

EAPL's original access arrangement proposed the use of the Cost of Service methodology (pursuant to section 8.4 of the Code) and a current cost accounting framework (real basis) to determine total revenue over the access arrangement period.

EAPL proposed the use of the price path approach (pursuant to section 8.3(b)) to establish the path of tariffs over the period. Commencing with the published tariff as a reference point, EAPL proposed that mainline tariffs in subsequent years be indexed according to the CPI-X formula. To ensure the equivalency of the price path approach and the strict cost of service approach, EAPL calculated the value of X such that the NPV of the forecast revenue (tariffs multiplied by volumes) was equal to the NPV of its revenue requirement based on forecast costs.

Although referred to as a price path approach, EAPL also proposed the inclusion of a pass through mechanism to allow it to recover the costs associated with new or increased taxes, charges, levies, imposts or fees.[32]

2.1.3 Commission's Draft Decision

The Commission acknowledged that EAPL had selected to determine its total revenue using the Cost of Service methodology and a current cost accounting framework, both of which were permitted under the Code. In relation to the manner in which EAPL proposed to vary tariffs over the access arrangement period, the Commission concluded that the price path approach and the adoption of the smoothing mechanism were acceptable and in accordance with the Code.

2.1.4 Submissions in response to the Draft Decision

No submissions were received specifically in response to the Commission's conclusions regarding the methodology utilised by EAPL to calculate its revenue requirements or the form of regulation used to determine the path of tariffs over the access arrangement period.

2.1.5 Revised access arrangement

In contrast to its original proposal to utilise the Cost of Service methodology, EAPL's revised access arrangement proposes the use of the NPV methodology applied on a real

[32] EAPL access arrangement, May 1999, pp. 9-10.

basis to determine its total revenue requirement over the expected life of the assets. EAPL has also proposed the use of price path form of regulation to establish the path of tariffs over the remainder of the economic life of the MSP.

In establishing the price path of tariffs over the access arrangement period, EAPL proposes that the published tariff applicable at the time the access arrangement is lodged be used as the reference point with mainline and lateral tariffs then adjusted annually according to the CPI-X mechanism. In addition to this adjustment, EAPL has proposed that the introduction of certain costs, such as those associated with the introduction of FRC and new or increased taxes, charges, levies, imposts or fees, be deemed specified events under the trigger event adjustment approach and in effect passed through to users.[33]

2.1.6 Submissions in response to the revised access arrangement

No submissions were received specifically in response to EAPL's proposal to utilise the NPV approach to calculate its revenue requirement and the price path approach to determine the path of tariffs over the access arrangement period. However, submissions were received regarding the individual parameters used to derive the revenue requirement and reference tariff. These submissions are discussed in the relevant sections in this chapter.

2.1.7 Commission's considerations

EAPL has proposed the use of the NPV methodology applied on a real basis to determine the revenue requirement for the MSP over the term of the initial access arrangement period. The Commission is satisfied that this proposed methodology is consistent with sections 8.4 and 8.5A of the Code. As to the proposed form in which tariffs will vary over the access arrangement period, the Commission acknowledges that the adoption of a combined price path and trigger event adjustment for reference tariffs is within the discretion of EAPL under section 8.3(e) of the Code. The Commission therefore considers that the relevant Code requirements are satisfied. A further discussion of the NPV approach is provided in sections 2.5 and 2.9 of this *Final Decision*.

2.2 The initial capital base

2.2.1 Code requirements

The initial capital base – existing pipelines

For existing pipelines, the Code (sections 8.10 (a) and (b) and 8.11) requires that normally the value of the ICB should not fall outside the range of depreciated actual cost (DAC) and depreciated optimised replacement cost (DORC). In establishing the ICB, the Code also requires the Commission to consider:

- other well recognised asset valuation methodologies (section 8.10(c)) and the advantages and disadvantages of these methodologies (section 8.10(d));

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[33] EAPL revised access arrangement information, 7 July 2003, pp. 21-27.

- international best practice and the impact on the international competitiveness of energy consuming industries (section 8.10(e));
- the basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the covered pipeline, and the historical returns to the service provider from the covered pipeline (section 8.10(f));
- the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code (section 8.10(g));
- the impact on the economically efficient utilisation of gas resources (section 8.10(h));
- the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the pipeline in question) (section 8.10(i));
- the price paid for any asset recently purchased by the service provider and the circumstances of that purchase (section 8.10(j)); and
- any other matters the Commission considers relevant (section 8.10(k)).

General principles

In addition, the Commission is guided by the objectives in section 8.1:

> (a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of 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.
>
> To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which that can best be reconciled or which of them should prevail.

In the Epic Decision the Court of Appeal stated that in considering the factors in section 8.10, the regulator must give weight to them as fundamental elements in its decision in establishing the value of the ICB. In addition, when establishing the value of the ICB, regulators must take into account the objectives in section 8.1 of the Code. To the extent that these objectives conflict, the regulator, in using its discretion to reconcile the objectives and resolve the conflict, must be guided by the factors in section 2.24, which are:

> (a) the legitimate business interests and investment of the service provider;
>
> (b) firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline;
>
> (c) the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline;

(d) the economically efficient operation of the covered pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of users and prospective users; and

(g) any other matters that the Commission considers are relevant.

The Court of Appeal stated:

> … The last paragraph of s 8.1 recognises that the objectives (a) to (f) in s 8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s 8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s 8.1 itself. Of necessity, the Regulator must have guidance outside of s 8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s 2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s 8.1 the Regulator should take into account the factors in s 2.24(a) to (g). I will return to the implications of this later in these reasons. Were that not so, inevitably the Regulator would need to have regard to the general scope and objects of the Act, as revealed by the preamble, in exercising the discretions contemplated by the last paragraph of s 8.1.[34]

In determining the value of the ICB for the MSP the Commission has had regard to the findings of the Court of Appeal in the Epic Decision.

2.2.2 Original access arrangement

In May 1999 EAPL proposed a value for the ICB of $666.7 million, which included a valuation of the pipeline system as well as allowances for working capital and 'access arrangement costs'. The valuation of the pipeline system was equivalent to EAPL's DORC calculation at that time. EAPL used straight line depreciation to derive its DORC value from its proposed optimised replacement costs (ORC) of $1058.6 million.

EAPL's proposed value for ORC was based on a report prepared for EAPL by Venton and Associates Pty Ltd (the Venton report).[35] Included in Venton's ORC estimate was a 10 per cent contingency factor on various cost factors, including linepipe, survey and easement, environment, pipeline construction, stations and facilities, owner's project costs, engineering, procurement and project management. The contingency was in the order of $82 million dollars. In justifying the 10 per cent contingency, Venton stated:

> The amounts allowed in the estimates of the project approvals represent a reasonable cost for the activities. If this project was developed as a greenfields project it is possible that the project management would have some difficulty in managing the work within the estimated amounts. This is because the project profile would be such that it would attract a great deal of attention from Government and Landowner/Landholder/Land Claimant Groups that could increase the cost significantly.

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34 [2002] WASCA 231, par 85.

35 Venton and Associates Pty Ltd, *Optimised design and cost estimate EAPL pipeline network*, 20 June 1999.

> However, there is a significant allowance for Contingency (omissions) in the capital cost estimate that should accommodate omissions in this area.[36]

In addition to the 10 per cent contingency factor, Venton stated it considered the accuracy of it cost estimates to be plus or minus 20 per cent (which is equivalent to a range for the ORC of $846 million to $1270 million).

Inherent in EAPL's DORC calculation was an assumed life of 60 years for the Moomba to Wilton pipeline segment and 80 years for other segments. A shorter life was assumed for the Moomba to Wilton pipeline because of deterioration due to stress corrosion cracking and the older technology used in constructing the pipeline. The DORC for the Moomba to Wilton section was calculated as 36/60ths (or 60 per cent) of the ORC (36 years being the remaining life at the time).

Subsequent to its original proposal EAPL submitted that the life of the Moomba to Wilton section could be extended to 80 years through refurbishment by re-coating the pipeline in areas where the coating had deteriorated. EAPL's projected cost of the refurbishment was $560 000 per km for 250 km between the years 2033 and 2056.[37]

In addition, in August 2000 EAPL submitted an alternative methodology devised by Agility Management Pty Ltd (Agility) for deriving DORC from ORC (the Agility approach).[38] Agility drew on statements made in past reports by the Commission, and in particular the *Draft Statement of Principles for the Regulation of Transmission Revenues (DRP)*, to support its alternative approach. Broadly, Agility emphasised that the DORC derivation from ORC should be independent of the past or proposed frameworks for establishing tariffs. Instead, the value should be based on the net present value (NPV) of revenues that could be generated by the assets over their remaining useful life as if tariffs were set on the basis of what would be charged by a new entrant in a contestable market. EAPL estimated the value for the MSP on this basis to be in excess of $900 million.

2.2.3 Commission's Draft Decision

Optimised replacement costs

The Commission engaged the services of Kinhill Pty Ltd to review the Venton report. Kinhill compared the estimated overall unit costs of the MSP contained in the Venton report, $834 to $1241/mm/km, with unit costs based on Australian pipelines overall of $500 to $1 000/mm/km. Kinhill also noted that at $1010/mm/km the Moomba to Young pipeline, which dominates the capital cost, was on the high side of the historical range. Kinhill found that this was mainly due to a higher cost for managing land acquisitions and approvals based on experience with recent Australian pipelines. Kinhill concluded, however, that:

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36 Venton and Associates Pty Ltd, *Optimised design and cost estimate EAPL pipeline network*, 20 June 1999, p. 20.

37 EAPL letter to the Commission, 21 September 2000, p. 2.

38 Agility Management Pty Ltd, *The Construction of DORC from ORC*, August 2000.

> In general, the capital costs in the Venton Report, while at the high end of historical transmission costs, are justifiable and reasonable in view of the higher costs of managing land acquisition and approvals recently experienced with Australian pipelines.[39]

The Commission essentially accepted Venton's proposed ORC with the exception that it disallowed the contingency factor of $82 million. The Commission considered that while it may be appropriate for a business to include a contingency factor in its estimates of the projected costs of constructing a new pipeline, that was not the case when determining the regulatory value of the ICB for an established pipeline. Accordingly, the Commission proposed an ORC value of $976.1 million.

Depreciated optimised replacement costs

In the *Draft Decision* an asset with a life of 50 years was used to determine a DORC value of $539.5 million. In determining this value, past levels of recovery of depreciation were taken into account (section 8.10(f) of the Code). To determine the DORC from ORC the Commission used traditional straight line depreciation in preference to the Agility approach. The Commission gave two main reasons for rejecting the Agility approach:

- it was inconsistent with the depreciation proposed in the regulatory framework and the historical treatment of depreciation for the purpose of setting tariffs and lost its relevance for setting an ICB which needed to comply with fairness requirements of the Code, (sections 8.10(f) and (g) in particular); and
- the hypothetical contestable model used to establish the revenue profiles of new and existing assets had limited relevance to the regulated gas pipeline industry.

Accumulated deferred taxes

From the DORC value of $539.5 million, the Commission proposed to deduct the value of EAPL's accumulated deferred taxes to date. The Commission calculated this value at $37.4 million. The Commission considered that the accumulated deferred taxes represented a free source of capital to EAPL and should be deducted from the asset base.

In light of submissions made on this matter and consistent with the Commission's position in the MAPS Final Decision[40], the Commission in this *Final Decision* for the MSP has not reduced the value of the ICB by the amount of deferred tax liabilities.

Working capital

The Commission proposed to remove the value of working capital from the ICB. The rationale for this approach related to the methodology adopted by the Commission for its modelling of cash flows. Rather than model the timing of EAPL's cash flows throughout the year, the Commission assumed in its model that all costs and revenue are incurred on the last day of each year. In reality, EAPL's cash flows would occur at regular intervals throughout the year, giving EAPL a benefit above the regulated

[39] Kinhill Pty Ltd, *Review of the asset valuation of the EAPL pipeline network,* 6 January 2000, p. 7.

[40] ACCC, *Final Decision: Access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, p. 21.

revenue equal to the time value of money on the net cash flow received throughout the year. The Commission considered that this benefit more than compensated EAPL for any gap between payments and collections during the year.

Residual economic value and sale price

The Commission calculated a residual economic value (based on economic depreciation and a commercial rate of return) of $1.29 billion as at 1994, the year the MSP assets were sold by the Australian Government to EAPL. Since the sale price of $539.5 million was considerably less than the residual economic value, it was clear that the Australian Government had not earned a commercial rate of return on its investment, but rather had only recovered its costs. Statements made by TPA in its annual reports suggested that this was the Government's objective during its ownership of the pipeline.

The Commission interpreted the difference between the residual value and the sale price as the value of a subsidy provided by the Government in establishing the pipeline. The Commission considered that setting a value for the ICB above the sale price would result in a windfall gain to the new owner by effectively appropriating some of the subsidy ostensibly intended for industry development.

Proposed value of the ICB

The Commission proposed a value for the ICB of $502.081 million, which was equivalent to DORC of $539.5 million plus an allowance for access arrangement costs and less the value of accumulated deferred taxes of $37.4 million. The Commission also noted that this value was broadly consistent with EAPL's investment in the pipeline as represented by the 1994 sale price of $534 million.

2.2.4 Submissions in response to the Draft Decision

Optimised replacement costs

In a submission to the NCC with respect to the revocation of coverage of the MSP NECG (on behalf of EAPL) was critical of the Commission's proposal to reduce the ORC by the $82 million contingency factor. NECG stated:

> A hypothetical new entrant must, according to the thought experiment construct an optimal asset. In doing so it will face a degree of uncertainty as to the ultimate construction cost. The hypothetical entrant cost benchmark is based on ex ante cost estimates, which would include an allowance for construction cost overruns. This is precisely the role played by the construction contingency allowed for in EAPL's Access Arrangement, but disallowed by the ACCC.[41]

In response National Economic Research Associates (NERA) supported the stance taken by the Commission to discount the amount of the contingency factor. NERA stated:

> 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

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[41] NECG, *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price*, 11 February 2002, p. 13.

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. 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.[42]

EAPL asked Venton to comment on the Commission's proposal in its *Draft Decision* that the ORC estimate should be discounted by the amount of the contingency. Venton disagreed with the Commission's proposed approach. Venton stated that although it had considerable knowledge of the MSP pipeline routes, it did not have a detailed knowledge of several factors relating specifically to the MSP, for example, terrain and soil types and land costs. Consequently Venton established its estimated costs using assumptions, general industry knowledge and historical cost data. Accordingly, Venton added a 10 per cent contingency factor to cover cost items that would only be revealed by a more 'detailed estimating process based on well developed designs, and detailed investigation of other contributing cost factors.'[43]

Venton acknowledged that an argument could be raised that the 10 per cent contingency factor may be on the high side:

While a detailed analysis of the estimate for omissions and cost accuracy was not undertaken at the time of the 1999 report, it was considered that 10% was reasonable. A more detailed analysis may show that 7.5% would have been a more appropriate allowance.

It would be most unlikely to find that 0% was an appropriate allowance.[44]

Depreciated optimised replacement costs

EAPL reiterated the appropriateness of the Agility approach to the construction of DORC from ORC that it proposed to the Commission in August 2000 and which it stated is consistent with the Commission's DRP. EAPL also submitted a report by Professor Stephen King in support of the Agility approach.[45] As EAPL submitted, Professor King stated that:

- the Agility approach was consistent with the DRP and the interpretation of DORC presented in the Commission's 1998 Victorian gas decision;

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42 NERA, *The hypothetical new entrant test in the context of assessing the Moomba to Sydney Pipeline prices*, September 2002, pp. 26-27.

43 Venton and Associates Pty Ltd, *East Australian Pipeline Limited optimised replacement cost – estimate contingency*, 12 May 2003, p. 1 (prepared on behalf of EAPL).

44 Venton and Associates Pty Ltd, *East Australian Pipeline Limited optimised replacement cost – estimate contingency*, 12 May 2003, p. 2 (prepared on behalf of EAPL).

45 S. King, *Report on the construction of DORC from ORC*, 14 February 2001.

- the straight line adjustment adopted by the Commission in the *Draft Decision* was arbitrary, lacked economic justification and was inconsistent with the DRP and previous decisions;
- past levels of recovery of depreciation were irrelevant to the construction of DORC from ORC; and
- the depreciation schedule implicit in the construction of DORC from ORC did not place any constraints on the depreciation schedule of the ICB contained in the access arrangement.

Based on the Agility approach to the construction of DORC from ORC, EAPL stated that the DORC for the MSP is equal to approximately $940 million.

The Agility approach to depreciation is forward looking and independent of past levels of recovery of depreciation. EAPL disagreed with the position adopted by the Commission in its *Draft Decision* that past depreciation profiles should be taken into account when determining the value of DORC. According to EAPL, several of the factors that the regulator should have regard to under the Code when establishing the value of the ICB are 'economic based and forward looking with no particular linkage to actual accumulated depreciation.'[46] Accordingly, EAPL disagreed with the reliance placed by the Commission on past levels of recovery of depreciation in calculating the value of DORC.

Duke Energy International (DEI), the owner of the EGP, was also critical of the Commission's rejection of the Agility approach to deriving DORC from ORC.

1994 sale price and residual economic value

EAPL was critical of the emphasis placed by the Commission on the 1994 sale price. EAPL disagreed with the Commission's conclusion in that the difference between the residual asset value as at June 1994 and the sale price represented a subsidy provided by the Government in establishing the pipeline up to the time that the pipeline was sold. According to EAPL:

> … it was not the intention of the Government to provide a subsidy to the natural gas industry in New South Wales. If it had been the intention of the Government to perpetuate a subsidy it would have been open to it to do so. The fact is that it did not. Far from seeking to entrench a subsidy, the Government which ultimately conducted the sale had sought to underpin a maximum sale price.[47]

Furthermore, EAPL was critical of the emphasis placed by the Commission on any windfall gain accruing to EAPL from setting a value for the ICB in excess of the sale price. EAPL contended that if in the course of commercial negotiation a buyer purchases an asset at a price below the net present value to the buyer of the future cash flows, the difference is an amount won by the buyer in negotiation and should not be confiscated by the regulator from the buyer. EAPL stated:

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46 EAPL response to the Draft Decision, 14 March 2001, p. 14.

47 EAPL response to the Draft Decision, 14 March 2001, p. 10.

> The 1994 sale and purchase of the MSP was negotiated on a commercial basis in an environment where each party was seeking to maximise its position. The value of the revenue stream from the foundation contract alone is assessed to be $586m ($1994) which exceeds the purchase price of the pipeline ($534m). The purchase price is not the determinant of the pipeline's value to EAPL. The difference between the purchase price and the assessed value of the future cash flows acquired in the purchase must be viewed as value which rightfully accrues to the owner: it must not be confiscated.[48]

EAPL argued that as no subsidy existed, users would not be disadvantaged by an asset value set in accordance with the economic written down value (which EAPL assessed at $1700 million as at June 2000). That is over the life of the assets users 'would be paying no more than the full value of the pipeline.'[49]

Reasonable expectations under prior regime

Section 8.10(g) of the Code requires the Commission, when establishing the value of the ICB, to take account of the reasonable expectations of persons under the regulatory regime that applied to the MSP prior to commencement of the Code. In EAPL's opinion its reasonable expectation was a value of at least $666 million, which was the value put forward in its proposed access arrangement. EAPL stated:

> EAPL expressed its expectation by reference to the value of DORC. However, it is wrong to construe EAPL's statement to mean that its expectation under the prior regulatory regime is the value of DORC proposed in the Draft Decision i.e. $539m. The value of EAPL's expectation under the prior regulatory regime is at least $666m, which happened to be EAPL's assessment of DORC at the time it submitted the Access Arrangement Information under the current regime.[50]

Initial capital base

While EAPL stated that $940 million (its assessment of the value of DORC) would not be an unreasonable value for the ICB, it did not propose this figure as the value for the ICB. EAPL stated:

> Alternatively, if $539m was considered to be the appropriate value for the ICB on the basis of the mistaken values assumed for key factors in the Draft Decision, then a value of at least $740m would be expected when the corrected values are taken into account.[51]

The Energy Users Association of Australia (EUAA) supported a value for the ICB of $100 million in accordance with DAC. EUAA did not support the sale price as an appropriate valuation method and points to the experience in the Victorian gas industry as evidence that asset values and sale prices bear little relationship.[52] EUAA also opposed the inclusion of the costs to EAPL of preparing the access arrangement on the basis that a 'large number of organisations have incurred significant costs in participating in the review and these are not refundable'.[53]

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48 EAPL response to the Draft Decision, 14 March 2001, p. 11.

49 EAPL response to the Draft Decision, 14 March 2001, p. 13.

50 EAPL response to the Draft Decision, 14 March 2001, p. 13.

51 EAPL response to the Draft Decision, 14 March 2001, p. 15.

52 EUAA submission 21 February 2001, pp. 1-2.

53 EUAA submission 21 February 2001, p. 2.

DEI stated that, as the EGP was in direct competition with the MSP, the Commission should take into account section 8.10(i) of the Code when establishing the value of the ICB of the MSP, even though the EGP did not provide the same point-to-point service as the MSP. Section 8.10(i) states that the regulator should consider the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the pipeline in question).

DEI stated that it would not be able to compete with the MSP if the tariffs proposed by the Commission in its *Draft Decision* were adopted. DEI submitted that in setting the value of the ICB for the MSP the Commission should have regard to the 'average costs' of the EGP of $0.86/GJ. DEI stated that the *Draft Decision*:

> … has set a new benchmark price for transport of contestable volumes of gas to Sydney at a level which is approximately half the average cost level for the EGP.[54]

2.2.5 Revised access arrangement

Depreciated optimised replacement costs

In its revised access arrangement for the MSP dated 30 April 2002, EAPL made no changes to the value of ORC that was submitted in May 1999. In light of revisions to its proposed volume forecasts initially submitted to the Commission in March 2003, the Commission enquired of EAPL any whether changes to the optimised design of the MSP would be warranted.

EAPL commissioned Venton to undertake a desktop review of the original ORC estimate and to provide an assessment of the sensitivity of the ORC value to the change arising from the latest revised volume forecasts.[55] Venton concluded that any reduction in the ORC resulting from the lower revised volume forecast would be minor, in the order of a 3.6 per cent reduction. As this was within the range originally estimated by Venton, EAPL submitted that the original ORC estimate still represented the best basis for establishing the ORC for the MSP. EAPL submitted that this approach was appropriate in the absence of a more detailed review of the ORC to take into account any changes in circumstances since the original ORC was estimated.

Venton found that, while a reduction in the size of some of the sections of the MSP could be achieved as a result of the lower volume forecasts, this would be offset by the need for additional compressor stations to accommodate peak winter throughput. Accordingly, the net reduction in the ORC estimate is minor.

In June 2002, EAPL submitted a value for DORC of $972.7 million based on the Agility approach, which updated the figure of $940 million proposed by EAPL in its submission in response to the Commission's *Draft Decision*.[56]

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[54] DEI submission 9 February 2001, p. 3.

[55] EAPL submission, 23 May 2003 and Venton and Associates Pty Ltd, *Moomba to Sydney Pipeline review of optimised design for 2003 load reforecast: Report for East Australian Pipeline Limited*, 20 May 2003.

[56] EAPL response to information requested by Commission 20 June 2002, p. 1.

In further revisions submitted to the Commission in July 2003 EAPL proposed a value for ORC of $1042.3 million and for DORC of $972.3 million.[57] The value for ORC was the 1999 value of $1058.6 million less $16.3 million for disposed assets.[58] The ORC and DORC values proposed by EAPL and being considered by the Commission in this *Final Decision* are shown in Table 2.2.5.1 by pipeline segment and asset class.

Table 2.2.5.1: ORC and DORC proposed by EAPL (2000 $ million)

	ORC	DORC
Pipeline segment		
Moomba to Wilton	879.5	813.4
Dalton to Canberra	19.2	18.3
Young to Lithgow	49.6	48.2
Junee to Griffith	30.8	30.5
Young to Wagga	33.6	32.0
Wagga to Culcairn	29.6	29.7[(a)]
Total	**1042.3**	**972.3**
Asset class[(b)]		
Pipelines (Moomba to Wilton)	819.9	
Pipelines (Young to Culcairn)	59.4	
Pipelines (laterals)	90.8	
Compressors	58.1	
Metering	14.0	
Total	**1042.3**	

Note: (a) EAPL provided no explanation for DORC being greater than ORC.
(b) EAPL did not submit DORC values for individual classes of assets.

Source: EAPL access arrangement information, 7 July 2003, pp. 9-10.

The initial capital base and EAPL's reasonable expectations

In its revised access arrangement of May 2002, EAPL proposed a value for the ICB of $740 million. While the proposed value for the ICB of $740 million was not based on any particular valuation methodology, EAPL submitted that if the 'errors' in the *Draft Decision* were corrected, then it followed that the value for the ICB would be considerably higher than that proposed by the Commission in its *Draft Decision*. It was EAPL's view at that time that a value for the ICB of $740 million would have represented a reasonable balance of the interests of EAPL and the interests of users and prospective users.

Following the Epic Decision, EAPL lodged a further submission with the Commission in which it revised its proposed value for the ICB to $768 million. In proposing this

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57 EAPL revised access arrangement information, 7 July 2003, pp. 8-10.

58 EAPL submitted that as a consequence of the establishment of the APT and associated outsourcing arrangements, certain assets – SCADA system, motor vehicles, tools, plant and mobile equipment - were disposed of in June 2000 (Access arrangement information, July 2003, p. 11).

value, EAPL relied on section 8.10(g) of the Code which requires the regulator to have regard to the reasonable expectations of persons under the regulatory regime that applied to the regulated pipeline prior to the commencement of the Gas Code. EAPL stated:

> Having taken the matters in sections 8.1 and 2.24 [of the Code] into account, the minimum value which would properly recognise the interests of EAPL as required under the Code while still recognising the interests of [the] User is the amount which represents the reasonable expectations of EAPL under the prior regulatory regime, being at least $768m.[59]

EAPL's approach to determining its reasonable expectations under the prior regulatory regime was to identify its actual expectations and then test them for reasonableness. EAPL stated that its actual expectations have been determined from corporate documents prepared prior to the introduction of the Code. Those expectations related to both volumes and prices which formed the basis of future cash flows. EAPL submitted that the NPV of those expected cash flows fell within the range of $768 to $972 million.[60]

EAPL tested the 'reasonableness' of these expected cash flows by examining the validity of its assumptions on volume and price. In relation to volume, EAPL submitted that its anticipated volumes were reflected in actual demand to date. In relation to price, EAPL argued that the reasonableness of its assumptions depended on market expectations of price.

EAPL's expectations were based on the prices under the GTA between EAPL and AGLWG, and EAPL's published prices for other users. EAPL noted that its published prices were largely reflected in third party contracts for use of the pipeline. Hence EAPL submitted that its forecast cash flows, based on the GTA prices and published prices, represented a reasonable expectation under the regulatory regime that existed prior to the Code.

EAPL submitted that it was reasonable to base assumptions about non-GTA volumes on published prices because: those prices were not significantly different from contract prices and were expected to decline in the longer term; and EAPL had been able to negotiate prices at its published prices under the regime without access disputes being referred to arbitration.

Furthermore, EAPL argued that its reasonable expectations formed part of its agreement with the Government as part of the sale process and that the prior regulatory regime underpinned EAPL's reasonable expectations. EAPL submitted:

> The reasonable expectations of EAPL under the prior regulatory regime formed part of the agreement negotiated between EAPL and the Commonwealth Government in privatizing the MSP. The circumstances of the purchase of the MSP (set out in section 3.5) included the establishment of a regulatory regime specific to the MSP, which underpinned the reasonable expectations of EAPL at no less than $768m.[61]

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[59] EAPL submission, 5 November 2002, p. 5.

[60] This range was subsequently revised to $784 -$998 million, as discussed later in this section.

[61] EAPL submission, 5 November 2002, p. 11.

EAPL stated that a value of at least $768 million represented the value to EAPL of the deal (the purchase of the pipeline from the Australian Government). EAPL submitted:

> Indeed to establish an ICB at any lesser valuation is to respectively confiscate the benefit to EAPL of the deal attained in the privatisation process, a confiscation directly in contrast to the view held by the Court in the Epic Decision.[62]

Following further analysis EAPL revised its estimated value of the ICB from $768 - $972 million (based on its 'reasonable expectations') upwards to a range of $784 - $998 million.[63] On 23 June 2003 EAPL made a further submission in support of its argument that its 'reasonable expectations' valuation was underpinned by the 1994 sale agreement. EAPL submitted that the head agreement negotiated between the Australian Government and AGL (the *Moomba-Sydney Pipeline 51% Sale Agreement*) contained two key elements relating to EAPL's expectations under the regulatory regime prior to the introduction of the Code. They were:

- the arrangements under the foundation customer transportation agreement between AGL and EAPL (the GTA); and
- agreement as to the regulatory regime that would apply following the sale.

The regulatory regime referred to was contained in a condition precedent (clause 3.2(f)) of the 51% Sale Agreement, which stated:

> The coming into force of legislation of the Commonwealth Parliament substantially in the form of the Interstate Gas Pipelines Bill of 1993,[64] a copy of which is attached as Schedule 6 with such modifications as the Purchaser reasonably approves.[65]

EAPL submitted that of significance to its 'reasonable expectations' was that the prior regulatory regime:

- did not affect the provisions of the GTA – that is, prices under the GTA could not be changed and hence the prices specified in the GTA were a reasonable expectation of EAPL; and
- allowed EAPL to negotiate transportation for third parties.

In relation to the latter, EAPL stated that the issue for the Commission to consider is whether the use of published tariffs by EAPL to determine the ICB was reasonable. EAPL submitted that, as no access disputes were lodged with the Commission with respect to its published prices, its published prices for volumes in excess of the GTA represented a reasonable expectation of EAPL.

Furthermore, EAPL submitted that the purchase price embodied in the 51% Sale Agreement did not establish or limit the expected value of the MSP to EAPL. In addition, EAPL stated that the regulatory regime made no connection between tariffs to be charged and the purchase price.

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62 EAPL submission, 5 November 2002, p. 21.

63 EAPL letter to the Commission, 4 December 2002, Item 2, p. 2.

64 This bill was substantially embodied in Part 6 of the Moomba-Sydney Pipeline System Sale Act.

65 EAPL submission, 23 June 2003, p. 2.

In EAPL's view, the value of the ICB stemming from EAPL's reasonable expectations under the prior regime was best represented by its forecast cash flows that were undertaken in 1997/1998 and formed part of its five year plan. In conclusion, EAPL stated:

> …to establish an ICB at a value less than $784 million would retrospectively confiscate the value to EAPL of its reasonable expectations under the MSPSSA regulatory regime, both of which (ie EAPL's reasonable expectations and the MSPSSA regulatory regime) were established by the deal to purchase the MSP. It would at the same time provide users with a windfall gain which was never contemplated by the MSPSSA regulatory regime.[66]

In its July 2003 revised access arrangement information EAPL confirmed that its proposed value for the ICB was $784 million. However, for tariff setting purposes EAPL submitted an adjusted ICB of $779 million after taking account of disposal of assets valued at $5 million (deemed disposal value).[67]

Table 2.2.5.2 summarises the values by pipeline segment for the ICB that have been proposed by EAPL and are being considered by the Commission in this *Final Decision*. EAPL has allocated the total proposed ICB value across the various pipeline segments in accordance with the proportion of the total value of ORC that each pipeline represents. For example, the ORC value for the Moomba to Wilton pipeline ($879.5 million) represents 84.4 per cent of the proposed ORC for the entire system ($1042.3 million). Accordingly, EAPL has allocated to the Moomba to Wilton pipeline 84.4 per cent of its proposed value for the ICB.

In its May 1999 access arrangement information EAPL submitted that allocation of capital costs on the basis of ORC, rather than DORC, avoided any potential distortions caused by different asset ages. In the *Draft Decision*, the Commission proposed to accept the use of ORC as the methodology for allocating capital costs.

Table 2.2.5.2: EAPL's proposed ICB (2000 $ million)

	ICB
Moomba to Wilton	657.3
Dalton to Canberra lateral	14.4
Young to Lithgow	37.1
Junee to Griffith	23.0
Young to Wagga	25.1
Wagga to Culcairn	22.1
Total	**779.0**

Source: EAPL access arrangement information, 7 July 2003, p. 12.

66 EAPL submission, 23 June 2003, p. 3.

67 EAPL revised access arrangement information, 7 July 2003, pp. 11-12.

2.2.6 Submissions in response to the revised access arrangement

In response to the revised access arrangement DEI restated the arguments in its submission to the *Draft Decision* that the Commission had failed to give adequate consideration to the fact that the MSP and EGP are in direct competition. DEI submitted that the Commission should have regard to the costs of the EGP in setting the value for the ICB of the MSP.

In its submission in response to the Epic Decision, DEI stated that the Commission erred in the *Draft Decision* in its application of the Code, particularly in relation to the ICB. According to DEI, two areas in which the Commission erred were:

- the incorrect treatment of DORC as the maximum value for the ICB; and
- the failure to give adequate weight to EAPL's legitimate business interests.

In response to the revised access arrangement, the EMRF opposed the valuation put forward by EAPL (at that time $740 million) and supported the Commission's proposed *Draft Decision* ICB of $502 million. EMRF also opposed the methodology for calculating DORC advocated by Agility. In a further submission the EMRF opposed the revised value of $768 million proposed by EAPL for the ICB and argued that such tariffs would not be 'reasonable' in the context of the Epic Decision discussion of 'reasonable returns' and 'reasonable expectations'. The EMRF stated:

> To allow this would mean raising tariffs to a level that would mean the embedding of supra monopoly rents, and thereby clearly against the interests of users and prospective users of the MSP (and inconsistent with the principles and interpretation of the Code and covered in the Epic Decision).[68]

2.2.7 Commission's considerations

Introduction

In this section the Commission turns its attention to the various factors to which it is required to have regard under section 8.10 of the Code. Viable options for the ICB produced from this process are then evaluated comparatively in terms of the objectives in section 8.1 of the Code. The Commission's conclusions arising from this assessment are set out in the final part of this section.

Interpretation of section 8.10 factors

The Court of Appeal provided guidance on the interpretation of the factors contained in section 8.10 of the Code. The relevance of each of these factors to the value of the ICB is considered below.

While noting that the Code requires that the value of the ICB should not 'normally' fall outside the range of DAC and DORC, the Court of Appeal stated that it is clear from section 8.11 that other methodologies are to be considered and the advantages and disadvantages of each are to be weighed. Moreover, the Court of Appeal observed that

68 EMRF submission, 28 January 2003, p. 1.

each asset valuation methodology should not be evaluated according to theory of economic efficiency alone, but are to be considered and evaluated on their merits.[69]

Depreciated actual costs (section 8.10(a))

Section 8.10(a) of the Code requires the Commission to consider the value that would result from taking the actual capital cost of the covered pipeline and subtracting the accumulated depreciation for those assets charged to users (or thought to have been charged to users prior to the commencement of the Code).

On the concept of depreciated actual costs (DAC), the Court of Appeal stated:

> Under this method the actual capital cost of the pipeline is taken as the starting point. From this there is subtracted accumulated depreciation which has been charged to users prior to the commencement of the Code. Expert evidence would suggest that it is usual to take the net book value and to depreciate this in line with accounting standards. The method requires that allowance be made for inflation. While this can be done by indexation of the asset base, more commonly, it seems, this is dealt with by allowing for inflation in the Rate of Return which is a separate element in the Cost of Service methodology contemplated by s 8.4.[70]

In its original access arrangement information EAPL submitted that the DAC for the MSP was in the order of $470 million, based on the price EAPL paid to the Australian Government in 1994 ($534 million) and taking into account capital expenditure and book depreciation since that date.[71]

In its response to submissions to the original access arrangement, EAPL calculated a DAC for the MSP based on historical data from both TPA and EAPL. The resulting DAC of approximately $100 million took into account the actual costs of the MSP in 1976, together with capital expenditure and depreciation since that year.

The Commission considers that the value of DAC consistent with the Code is one that is calculated from the date that the MSP was originally constructed in 1976, notwithstanding the change in ownership in 1994. Accordingly, the Commission considers that the appropriate value of DAC for the MSP is $100 million.

Depreciated optimised replacement cost (section 8.10(b))

Section 8.10(b) of the Code requires the Commission to take into account the value that would result from applying the DORC methodology in valuing the pipeline.

Estimation of DORC is a two-fold process:

- estimate the efficient current costs of replacing the existing asset assuming optimal configuration and size and using modern engineering equivalent materials (the ORC); and
- depreciate the ORC to take account of the existing asset's lower service potential as a consequence of its remaining life being less (usually) than the useful life of the replacement asset.

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69 [2002] WASCA 231, par 176.

70 [2002] WASCA 231, par 163.

71 EAPL access arrangement information, 5 May 1999, p. 23.

In its DRP, the Commission provided two definitions of what DORC attempts to measure:

- One interpretation of DORC is that it is the valuation methodology that would be consistent with the price charged by an efficient new entrant into an industry, and so it is consistent with the price that would prevail in the industry in long run equilibrium.
- The second interpretation is that it is the price that a firm with a certain service requirement would pay for existing assets in preference to replicating the assets.[72]

The DRP also states that another justification for DORC is that it represents the maximum price that a firm would be prepared to pay for existing assets as opposed to installing new assets. In other words, if prices reflected a value in excess of DORC, then users would be better off if the existing system was scrapped and replaced with new assets.[73]

A similar argument has been put forward by Professor Stephen King. Professor King stated:

> As an alternative to purchasing new capital equipment, the new firm could purchase the assets of the existing firm. DORC may be interpreted as the maximum price that a new entrant would be willing to pay for these assets rather than purchase new assets.[74]

Likewise, NERA stated:

> The objective of DORC is to arrive at a valuation reflective of the price an entrant would be willing to pay for second-hand assets given the alternative of replacing them with new optimised assets that provide a certain service capability.[75]

Optimised replacement cost

The Commission accepts EAPL's submission that the recent revisions to its volume forecasts are likely to have only a minor impact on the ORC of the MSP. The value for ORC proposed by the Commission in its *Draft Decision*, $976.1 million, was expressed in year 2000 prices. The equivalent value in today's prices is $1092.9 million, which is the value for ORC adopted by the Commission in this *Final Decision*.

The Commission affirms its *Draft Decision* proposal to exclude the contingency factor of 10 per cent proposed by EAPL and its consultants, Venton and Associates. In its review of the Venton report, Kinhill concluded that the Venton's estimates were reasonable, although on the high side of an acceptable range. The exclusion of the contingency factor still results in a value for ORC within the 20 per cent tolerance level described in the Venton report.

The purpose of determining an estimate of ORC under the Code is to assist the regulator in establishing a value for the ICB for an existing pipeline. The Commission does not consider it necessary to replicate the cost estimations of a firm that is planning to construct a new pipeline. To make allowance for all contingencies that may occur

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72 ACCC, *DRP*, 27 May 1999, p. 39.

73 ACCC, *DRP*, 27 May 1999, p. 40.

74 S King, *Report on the construction of DORC from ORC*, 14 February, 2001, p. 6.

75 NERA, *Depreciation within ODRC Valuations - a report for the ACCC*, September 2002, p. 11.

and which produces a cost estimation at the high end of a feasible range is, in the Commission's view, contrary to the objectives in sections 8.1(a) (efficient costs) and 8.1(b) (replicating the outcomes of a competitive market) of the Code. A firm that is planning to construct a new asset may well include an allowance for contingencies that could increase the cost of construction. However, this does not mean that those contingencies will occur or that those costs will be incurred. It is equally likely that the project may cost less than was forecast. An ORC valuation seeks to estimate the actual cost of replacing the existing asset. To include in such a valuation an allowance for contingencies assumes that the replacement project would always suffer from the planned contingencies and would cost more than was forecast. This assumption is not justified.

Furthermore, one of the reasons given in the Venton report for the contingency factor was that the 'attention of Government and Landowner/Landowner/Land Claimant Groups' may increase costs significantly. This argument assumed that the estimate of ORC was based on considerations of a greenfields pipeline. By implication, these particular costs would be less if consideration of the ORC estimate was based on a brownfields project.

Finally, EAPL has provided little evidence to justify a level of 10 per cent for the contingency factor as opposed to some other value. The indicative nature of the 10 per cent level is demonstrated in Venton report of 20 May 2003 in which Venton stated that a more detailed analysis may produce a level of contingency lower than 10 per cent.

Depreciated optimised replacement cost methodology

While Section 8.10(b) requires the Commission to have regard to the value of DORC in establishing the ICB, the Code provides no guidance on the methodology to be used to depreciate the ORC to determine the value of DORC. Nor did the Court of Appeal address this matter, other than to say:

> …The expert evidence indicates that the DORC methodology is one of a number of methodologies which are described as "forward looking"…[76]

Although EAPL submitted that the Epic Decision supports the Agility approach to determining DORC, the Court of Appeal did not comment on the merits of any particular method of deriving DORC from ORC.

The traditional approach has been to assume that the asset depreciates uniformly (that is, on a straight line basis) over the life of the asset. DORC is calculated as a proportion of ORC in accordance with the ratio of the remaining life of the existing asset to the useful life of the replacement asset.

While the Code is silent of the method of depreciation to be applied, section 8.10(c) requires the Commission to consider the value of the pipeline that would result from applying 'other well recognised asset valuation methodologies'. Put in context, this suggests that the method to be used to determine the value of DORC must be a well

[76] [2002] WASCA 231, par 164.

recognised asset valuation methodology. Certainly the straight line method of depreciation falls within this category, in contrast with the Agility approach which would appear to be a relatively new method.

Under the Agility approach, DORC is the NPV of the first 'n' years of the cash flows of a hypothetical entrant in a contestable market (after taking account of any differences in operating costs between the existing asset and a new asset), where 'n' is the remaining life of the existing asset. The Commission engaged Sinclair Knight Mertz (SKM) as consultant to advise on the appropriate methodology for deriving the value of DORC from ORC that best meets the requirements and intentions of the Code. The Commission later engaged the services of NERA to critique both the SKM report and the approach proposed by Agility.

SKM recommended that the DORC[77] valuation be based on the traditional straight line methodology for determining the level of depreciation. SKM justifies its recommendation on the basis that straight line depreciation has been used in the past and it is the expectation of affected parties that straight line depreciation would be used under the current regulatory regime. SKM stated:

> As far as we are aware straight-line depreciation has been applied within the ODRC methodology for the initial capital base calculation for Australian gas and electricity networks…That we believe straight line depreciation has been previously applied tends to indicate that straight line depreciation is both part of the normal ODRC methodology, as well as being the likely expectation of the parties prior to the regime as to what the regime would provide in the ICB.[78]

To support its arguments SKM drew on a 1995 NSW Treasury Paper with respect to the NSW electricity system. SKM quotes from that document:

> Depreciation is a function of the total life and the remaining life of an asset. The generally accepted method of depreciating electricity network assets is on a straight line basis, although there are other approaches to estimating changes in an asset's value as it becomes "older" and its remaining life decreases. To ensure consistency, Network Businesses should use straight line depreciation.[79]

SKM also referred to Australian Accounting Standard AAS 4. While acknowledging that depreciation for tariff setting purposes need not be the same as accounting depreciation, SKM stated:

> Nevertheless the recommendations of Australian standards could provide an indication as to what the understanding of other parties might have been of the depreciation regime being applied in the absence of any prior signals to the contrary.[80]

SKM quoted AAS 4, clause 5.5.11:

> …The straight line method is a means of determining systematic allocations which are constant from reporting period to reporting period and is most commonly adopted because of its simplicity.[81]

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77 The terms ODRC and DORC are interchangeable although SKM has used the term ODRC.

78 SKM, *Depreciation within ODRC valuations: Report for ACCC*, June 2001, p. 8.

79 SKM, *Depreciation within ODRC valuations: Report for ACCC*, June 2001, p. 4.

80 SKM, *Depreciation within ODRC valuations: Report for ACCC*, June 2001, p. 7.

SKM also cited OFTEL's 1997 review of British Telecom's network charges. The review included a discussion of economic depreciation versus straight line depreciation. OFTEL considered two models, one based on economic depreciation and the other based on straight line depreciation. OFTEL noted that while its economic depreciation approach was conceptually the correct method for valuing assets, it was difficult to implement in practice because of the difficulties associated with forecasting future asset prices and maintenance costs. OFTEL stated:

> …the methodology requires a number of assumptions (eg about the future movements in asset prices and maintenance costs) in order to be implemented. These assumptions are difficult to forecast with confidence.[82]

NERA examined the DORC methodology from an economic perspective. NERA was critical of Agility's use of future revenue streams to determine DORC. NERA noted that an infinite range of revenue paths existed which would yield different values for DORC when DORC is calculated as the NPV of the future revenue stream over the life of the existing asset.

NERA submitted an alternative approach that focused on the cost differences (both capital and non capital) between new and existing pipelines. NERA's approach is based on the premise that DORC represents the price that a new entrant with a certain service requirement would pay for existing assets in preference to replacing them. In its report NERA stated:

> …the DORC valuation should balance the net present value (NPV) of the expected future costs associated with a decision to purchase a new asset and those associated with using the existing asset. Under this definition, the depreciation adjustment should reflect the differences in ***future*** costs associated with new and existing assets.[83]

NERA listed the following factors that would affect the value of DORC:

- remaining asset lives – the closer is the remaining life of the existing asset relative to that of the replacement asset, the closer will be DORC and ORC and the lower the depreciation adjustment;
- on-going operating and maintenance costs – existing costs will likely have higher operating and maintenance costs than their modern equivalent. The greater the difference in costs the more DORC will deviate from ORC, implying a greater depreciation adjustment;
- operating risks, such as that of break-down – the risks associated with existing assets are more likely higher than those associated with modern assets, implying a correspondingly lower valuation (these risks can be treated as a component of the ongoing cost; and
- the rate of technological change – if the rate of technological change is very high and the price of new assets is declining, there is benefit in delaying the purchase of a new asset to take advantage of lower prices.[84]

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81 SKM, *Depreciation within ODRC valuations: Report for ACCC*, June 2001, p. 8.

82 SKM, *Depreciation within ODRC valuations: Report for ACCC*, June 2001, p. 11.

83 NERA, *Depreciation within ODRC Valuations - a report for the ACCC*, September 2002, p. 2.

84 NERA, *Depreciation within ODRC Valuations - a report for the ACCC*, September 2002, p. 8.

NERA then developed a model, given various assumptions, for illustrative purposes. NERA's preliminary conclusion from the results of its model was that the straight line depreciation framework may be more consistent with the economic characteristics of the gas pipeline industry than the Agility approach. NERA did acknowledge, however, the limitations of its model from an empirical viewpoint:

> A rigorous analysis of the ORC to DORC estimation for the pipeline industry would require considerable further analysis as to the validity of these assumptions. Such analysis was beyond the scope of our terms of reference; instead this model is intended to be illustrative of the types of relationships that might emerge under varying assumptions.[85]

EAPL made submissions in response to both the SKM and NERA reports. EAPL was critical of the straight line approach recommended by SKM on the basis that DORC calculated in this manner does not reflect the underlying economic principles of the concept of DORC.

Although concurring with NERA on several points, EAPL considered that NERA misunderstood or misinterpreted some aspects of Agility's methodology. Notably, EAPL was critical of the emphasis placed by NERA on the distinction between revenue and costs. EAPL stated:

> In fact capital costs cannot be divorced from cash costs and revenues – they are simply different sides of the same coin i.e. stocks and flows.[86]

In its report NERA acknowledged that if the revenue stream reflects cost differences, the Agility approach is consistent with NERA's approach. NERA stated:

> It will always be possible to make assumptions about revenues that are founded in the costs the company faces and which will therefore result in the mathematical representation of the two models coinciding. In other words, if the revenues are assumed to reflect cost differences, then, yes the two models will provide the same answer.[87]

A further criticism by EAPL of NERA's report relates to NERA's comment that an infinite number of revenue paths is feasible. While acknowledging the veracity of NERA's statement, EAPL argued that 'the range of profiles that could be regarded as economically sensible and meaningful is relatively narrow'.[88]

Conclusions on DORC methodology

Methodologies that derive DORC on the basis of differences in future capital and non capital costs between the existing assets and replacement assets conceptually provide a sound economic basis. As NERA observed, however, 'this is an issue for ***empirical*** as much as ***analytical*** analysis'[89] To estimate the DORC for a particular pipeline requires long term estimates of the differences in magnitude and timing of the costs of the pipeline in question and a replacement pipeline. These can be industry-specific, such

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85 NERA, *Depreciation with ODRC Valuations - a report for the ACCC*, September 2002, p. 16.

86 EAPL, *Response by Agility on behalf of EAPL to NERA report entitled 'Depreciation within ODRC valuations',* November 2002, p. 3.

87 NERA, *Depreciation within ODRC Valuations - a report for the ACCC*, September 2002, p. 14.

88 EAPL, *Response by Agility on behalf of EAPL to NERA report entitled 'Depreciation within ODRC valuations',* November 2002, p. 3.

89 NERA, *Depreciation within ODRC Valuations - a report for the ACCC*, September 2002, p. 6.

as the rate of change in the price of new assets, or pipeline-specific, such as any refurbishment costs associated with the MSP.

EAPL originally proposed that the life of the Moomba to Wilton mainline was 60 years, in contrast to the 80 year life proposed for the laterals. The different asset lives reflected the older technology of the Moomba to Wilton mainline and its deterioration due to stress corrosion cracking. EAPL subsequently submitted that the life of the mainline could be extended to 80 years through refurbishment, with the refurbishment forecast to commence in the year 2033. EAPL has since submitted that refurbishment will be undertaken when required.[90] While the timing and extent of the refurbishment is problematic, it is one factor that would affect the value of DORC for the MSP.

The uncertainty surrounding the timing and magnitude of the differences in future costs, both capital and non capital, between existing and future assets makes it difficult to estimate a DORC based on this methodology with any degree of confidence. The same conclusion is reached whether this methodology is considered as a method of determining DORC for the purposes of section 8.10(b) or as a ‘well recognised asset valuation methodology’ under section 8.10(c). Hence, for the purposes of the MSP the Commission has used straight line depreciation to determine a value for DORC, which could be considered a proxy for the true economic value of DORC.

DORC and remaining asset life

The DORC valuation methodology is dependent on the remaining life of the existing asset. As mentioned above, in its original access arrangement EAPL proposed that the total life of the Moomba to Wilton pipeline was 60 years (remaining life 36 years) with a total life of 80 years for other sections of the MSP. Subsequently EAPL submitted that the life of the Moomba to Wilton section could be extended to 80 years through refurbishment.

For the revised access arrangement lodged in May 2002, EAPL submitted that in its view the life of the MSP is 80 years, including the Moomba to Wilton segment, and refurbishment would be carried out when and if required. The Commission has accepted EAPL’s submission that the life of the MSP is 80 years with a remaining life of 53 years.

In its *Draft Decision* the Commission calculated a value for DORC on the basis of an asset life of 50 years, which was the asset life that EAPL assumed in the past for depreciation purposes.

NERA stated that past levels of recovery of depreciation, while a relevant factor in setting the value of the ICB, should not be a consideration in determining the value for DORC, which is meant to be a forward-looking concept.[91] The concept of DORC as a forward-looking concept is also consistent with expert evidence given in the Epic Decision.

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[90] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 5.

[91] NERA, *Depreciation within ODRC Valuations- a report for the ACCC*, September 2002, p. 1.

This suggests that the DORC should be a product of the expected useful life of the pipeline today, which the Commission accepts is 80 years.[92] Accordingly, the Commission has calculated a DORC value of $715.1 million, based on straight line depreciation over an 80 year asset life.

While DORC is one factor under section 8.10 of the Code that the Commission must consider in setting the value of the ICB, the Commission has not set the value of the ICB solely by reference to DORC.

Other well recognised asset valuation methodologies (section 8.10(c))

Section 8.10(c) of the Code requires the Commission to consider the value that would result from applying other well recognised asset valuation methodologies in determining the value of the ICB.

EAPL submitted that the market price of an asset is one such methodology and the Commission must therefore take into account the price paid by APL for the shares in EAPL. EAPL stated:

> During its 2000 float, APT purchased all of the shares in EAPL, the only asset of which was the MSP. The quantum attributed to those shares can therefore be considered a valuation of the MSP. That amount was [confidential material omitted]. [93]

In the Epic Decision the Court of Appeal indicated that the circumstances of purchase are relevant to the consideration of whether a purchase price reflects the market valuation of a pipeline.[94] The Court of Appeal stated:

> The latter consideration [that is, the circumstances of purchase] is amply wide enough, in my view, to allow an examination of the price paid according to the standards of reasonable commercial judgement as to value, the examination of the extent to which that price might have been influenced by considerations such as the prospect of monopoly profits and, although it is not the present case, the careful scrutiny of transactions between related entities or transactions which may involve motivations unrelated to value which might affect the price paid…I should make it clear that I am not intending by these comments to make any exhaustive analysis of potentially relevant considerations.[95]

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92 The useful life of 80 years refers to the pipeline assets only. Different useful lives apply to other assets (for example, compressors) depending on the nature of the asset.

93 EAPL submission, 5 November 2002, p 15.

94 [2002] WASCA 231, par 173.

95 [2002] WASCA 231, par 172.

Section 8.10(j) of the Code is also of relevance to the Commission's consideration of EAPL's proposed market value for the MSP. Section 8.10(j) requires the Commission to consider the price paid for any asset recently purchased by the service provider and the circumstances of that purchase. Hence the market value methodology is relevant to a number of the considerations in section 8.10, particularly 8.10(c) (widely recognised methodologies) and 8.10(j) (recently purchased assets). In the Epic Decision the Court of Appeal noted the relationship between these sections in cases where the purchase price is said to reflect a market valuation:

> Where the purchase price is also advanced as reflecting the market valuation of the pipeline for the purposes of s 8.10(c), factors … relevant to the circumstances of purchase for the purposes of (j), would equally be relevant to the application of (c) and (d) to that market valuation.[96]

Accordingly, when deciding what weight to give the market value in setting the value of the ICB, the Commission should have regard to the circumstances of the acquisition:

- when considering the advantages and disadvantages of a market valuation methodology (as revealed by purchase price) under sections 8.10(c) and (d); and
- when considering the circumstances of an acquisition under section 8.10(j).

A preliminary issue is whether 'market value' is a 'well recognised asset valuation methodology' for the purposes of the Code. If it is not, the Commission is not required to consider it in establishing the value of the ICB. The Commission has concluded that market value is a well-recognised valuation methodology. This view is supported by the Epic Decision where the Court of Appeal considered Epic's argument that the purchase price was relevant under 8.10(c) as representing the asset's market value.[97] Accordingly, the market value is relevant for the Commission to consider in its determination of the value of the ICB.

However, a market value based on a recent purchase price may be a poor valuation methodology in a regulatory environment if the 'market value' itself was not subject to market pressures. If, in the absence of competitive pressures, a purchaser acquires the asset at a price that has monopoly returns embedded in the sale price, those monopoly returns will be masked when that value is used as the value of the regulatory asset base. The application of a normal rate of return on an inflated asset base to determine regulated tariffs would appear prima facie that the business is earning only a competitive return. However, the tariffs would be higher than those that would be expected in a competitive market.[98]

EAPL submitted that the 'APT purchase price' is the market value of the MSP based on the price paid by APT to acquire the shares in EAPL. EAPL acknowledged that the transaction was not an arm's length transaction, since it was not determined in a market transaction or by competitive tender. Nevertheless, EAPL submitted that 'the float of APT required due diligence investigations and expert advice as to the proper value of

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96 [2002] WASCA 231, par 173.

97 [2002] WASCA 231, par 173.

98 This is not to say that a purchase price that anticipates monopoly returns must automatically be excluded. However, in the absence of a competitive sale process or any other relevant factor under the Code, this proposition stands.

the assets included.'[99] Moreover, EAPL noted that the market price of the units in APT has increased since the acquisition of EAPL, suggesting the market considers the underlying value of the company assets is at least the proper value of the assets.

An examination of the price paid according to the standards of reasonable commercial judgment as to value is one factor which the Court of Appeal raised as bearing on the significance of a purchase price when setting the value of the ICB. This includes consideration of the extent to which the purchase price may have been influenced by considerations such as the prospects of monopoly rents.

Therefore, section 8.1(b) of the Code ('replicating a competitive market') would require the Commission to give weight to an acquisition which was an arm's length commercial transaction based on a sound commercial assessment of the value of the pipeline in the circumstances then prevailing and reasonably anticipated. By EAPL's own admission the acquisition of EAPL by APT was not an arm's length commercial transaction. AGL, a 76 per cent stakeholder in EAPL at the time of the float, is also a 30 per cent stakeholder in APT. In addition, the Commission notes that the sale was not conducted by tender. The circumstances of the sale give the Commission little cause for confidence that a valuation based on the purchase price in 2000 would replicate the outcome of a competitive market.

EAPL submitted that the price of APT units since the acquisition indicated that the purchase price of EAPL reflected the true market value of the MSP:

> …the validity of the price attributed to the EAPL shares might best be tested by the share price of APT, since the EAPL shareholding represents over 50% of the assets of APT. [Since the acquisition] the market place has increased the value of the shares in APT, evidence that the underlying value of the company assets is considered by the market to reflect at least the proper value of the assets.[100]

APT appears to have argued that the performance of its units proved that the 'purchase price' was a market valuation and that it provided a nexus between the acquisition of EAPL and the market, thus requiring the Commission to give weight to the purchase price in establishing the ICB. The market's valuation of an equity is likely to be considered relevant to the value of the underlying asset. Other things being equal, the purchase of an asset that coincides with an increase in equity value of the acquirer is consistent with the market considering that the acquirer did not pay too much for the asset.

However, a number of issues bear upon the weight which should be accorded to equity values in the present case. First, it is necessary to identify the precise set of assets owned by the equity issuer. Where the issuer owns only one asset there are firmer grounds to conclude the equity value represents the market's assessment of that asset compared to where the issuer owns several assets. In the present case the EAPL shareholding represents only a portion (albeit a significant portion) of APT's assets. It is therefore difficult to say with confidence that the market valuation of APT's equity is

[99] EAPL submission, 5 November 2002, p.15.

[100] EAPL submission, 5 November 2002, pp. 15-16.

attributable solely to investor attitudes to the MSP to the exclusion of APT's other assets.

Second, even if the MSP were the sole asset of APT, the value of APT equity is likely to be significantly affected by investor expectations as to potential returns, including returns from existing haulage agreements. A favourable stock market reaction to an acquisition is consistent with investors anticipating strong returns (in the case of the MSP, such returns may have been based on no more than existing haulage agreements). This suggests a valuation based on market price (as divined from equity values) would not necessarily replicate the outcome of a competitive market (section 8.1(b)). In the present case it is unlikely to do so, given the circumstances of APT's acquisition of EAPL.

Third, without unravelling the details of the APT float it is difficult to draw strong conclusions about the market's view of the value of the MSP from the mere fact that unit prices have increased since the float. Equity performance may be more illuminating where there has been a history of trading prior to the acquisition of an asset, giving a background against which the unit price reaction to an acquisition event might be judged. There is no such background in the present case as APT listed its units at about the same time as it acquired EAPL.

Moreover, unit price movements should be interpreted with care as they can be affected by factors other than the value of assets. For example, general movements in the equities market bear upon the price of individual equities. (Note, however, that APT's unit price rose more quickly than the ASX All Ordinaries index from June to October 2000). The valuation of equities may also be affected by changes in the relative levels of debt and equity within the listed entity.

Finally, at the time of the APT float in 2000 the MSP was a covered pipeline under the Code and the Commission's assessment of EAPL's proposed access arrangement was in progress. However, regulated tariffs had not been set and at that stage the Commission's *Draft Decision* had not yet been released.

In its offer document, APT stated:

> The directors have adopted a conservative set of assumptions for the EAPL IAB [initial asset base] and WACC in the Trust's forecasts….the regulatory assumptions adopted by the Directors in formulating the Trust forecasts have been reviewed as part of the Independent Regulatory Review Report by Deloitte Touche Tohmatsu and found to be reasonable.[101]

To the extent that the market value reflected the outcomes that APT hoped to achieve under the current regime, without any guarantee that those outcomes would be achieved, then a valuation of the regulatory ICB based on the market value is in a sense circular and self-serving. The circularity arises in that the market value of the MSP would be based on EAPL's expected outcomes (including the proposed value for the ICB) and then the market value would form the basis of the ICB, without the proposed outcomes being subject to regulatory scrutiny and tested for reasonableness in the first instance.

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[101] APT, *Buried Treasure – Offer document*, March 2000, Part 1, Investment Highlights, p. 29.

Advantages and disadvantages of each valuation methodology (section 8.10(d))

Section 8.10(d) of the Code requires the Commission to consider the advantages and disadvantages of each valuation methodology applied under sections 8.10(a), 8.10(b) and 8.10(c). However, section 8.10(d) itself provides no guidance to the regulator on what criteria it should use in its assessment of the advantages and disadvantages of each valuation methodology.

Accordingly, the Commission has had regard to the section 8.1 objectives in its consideration of section 8.10(d). The Commission's consideration of the section 8.1 objectives in relation to the ICB is discussed later in this section.

International best practice and impact on international competitiveness (section 8.10(e))

Section 8.10(e) of the Code requires the Commission in setting the value of the ICB to consider the international best practice of pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries. In the Epic Decision the Court of Appeal noted that the first limb of this criterion requires consideration of the international best practice in pipeline valuation.

The second limb of this provision requires consideration of the international competitiveness of energy consuming industries in Australia. The Commission believes that the international competitiveness of domestic industries is enhanced by low, but sustainable, input costs, such as gas transportation. As capital costs form the bulk of gas transportation tariffs, it follows that the lower the value of the ICB the lower will be tariffs to end users. This argument tends to support an asset valuation based on the lower end of the feasible range of asset valuations that is DAC.[102]

In response to EAPL's original access arrangement, Incitec drew on the North American experience to support the case for DAC, stating:

> …under a DAC regulatory environment, there is still a dramatic growth in Canadian Pipelines…, this voids the argument that only DORC can encourage pipeline growth.[103]

It is important to note, however, that the Code distinguishes between existing and new investment with regard to the value of the asset base. DORC is only relevant to the establishment of the value of the ICB of existing covered pipelines. Capital expenditure with respect to new covered pipelines, and new investment on existing covered pipelines, is added to the capital base at actual cost (subject to the relevant provisions of the Code).

The WA Regulator considered the issue of international best practice in asset valuation in his Draft Decision on the DBNGP. He considered the practices in the UK and US, as these are the two countries with the longest history of energy regulation. The WA

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[102] From an economic viewpoint, the argument tends to support an asset valuation that would ensure that the asset is retained in its current use. That is, any value in excess of scrap value. However, such an approach in the case of gas pipelines would result in a valuation that falls outside the normal DAC/DORC range and may not satisfy the objectives in section 8.1 of the Code.

[103] Incitec submission, 18 August 1999, p. 1.

Regulator concluded that the US regulators have traditionally relied on historical cost valuations, whereas UK regulators have relied on replacement cost methodologies such as DORC. The WA Regulator noted that UK regulators have in some cases adopted 'market valuation' approaches. Regarding the Australian regulatory experience, the WA Regulator stated regulators have used 'DORC' as the starting point and in some instances discounted the DORC in accordance with some criteria balancing the interests of the service provider and users. Typically, the criteria have been that regulated tariffs should not exceed existing tariffs. The WA Regulator concluded that there is no established or well accepted 'international best practice'.[104]

The absence of any established 'international best practice' methodology for determining the valuation of existing pipelines suggests that this criterion does not weigh heavily in favour of any of the possible methodologies that might be used to determine the value of the ICB for the MSP.

Basis for past tariffs, economic depreciation and historical returns (section 8.10(f))

Section 8.10(f) requires the Commission to consider the basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the covered pipeline, and the historical returns to the service provider from the covered pipeline.

In the Epic Decision the Court of Appeal noted:

> …it is to be observed that each of these considerations has a potential relevance to past investment decisions in respect of the pipeline, **particularly in a case where there has been a sale of the pipeline before the commencement of the Code**. [105] [Emphasis added].

The Court of Appeal noted that this section, as with section 8.10(g), might point towards a lower or higher ICB than might otherwise be assumed in a particular case. However, the Court of Appeal also found that these provisions reflect that part of the general objective of the legislation and the Code that the rights of access to third parties be on conditions that are fair and reasonable to owners and operators. It noted that these two provisions preclude the view that the Code is concerned only with forward-looking considerations in the establishment of the ICB.[106]

Residual economic value

EAPL submitted that the Commission should take into account a residual value of \$1700 million in determining the value of the ICB. The residual value applies an economic depreciation to investment to determine an residual asset value at a particular point in time. The \$1700 million figure is EAPL's updated value for the residual economic value of \$1291 million calculated by the Commission in its *Draft Decision*. EAPL stated:

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104 Independent Gas Pipelines Access Regulator, Office of Gas Access Regulation, WA, *Draft Decision: Proposed access arrangement Dampier to Bunbury Pipeline System*, 21 June 2001, Part B, pp. 145-147.

105 [2002] WASCA 231, par 168.

106 [2002] WASCA 231, paras 168–169.

> The Commission in the Draft Decision has recognised that EAPL may suffer a windfall loss and the users receive a windfall gain, should the ICB be set at less than residual economic value.[107]

This is a misinterpretation of the Commission's *Draft Decision*. The Commission did not state that EAPL would suffer a windfall loss if the value of the ICB is below the residual value. The residual value was calculated from the date the MSP was commissioned to the date it was sold to EAPL. During this time the service provider was TPA, not EAPL. In its *Draft Decision*, the Commission interpreted the difference between the sale price of $534 million and the residual value as the value of a subsidy provided by the Australian Government. EAPL disputed this interpretation and cited a letter from Senator Peter Walsh as evidence that no subsidy was intended.

Irrespective of whether the difference between the sale price and the residual value can be interpreted as a subsidy, the fact that the sale price achieved by the Australian Government was less than the residual economic value indicates that ultimately the Government did not earn a commercial rate of return on its investment. The Commission understands that it was neither the Government's intention to earn a commercial return, nor was it permitted under the agreement between AGL and TPA. The Australian National Audit Office (ANAO) noted in relation to the haulage agreement between AGL and TPA:

> This agreement, inter alia, granted AGL the right of refusal on any sale of the pipeline and guaranteed that TPA would achieve cost recovery by 2006 and modest profits after that until 2016.[108]

EAPL also commented:

> From the commencement of operations of the Moomba-Sydney pipeline by The Pipeline Authority in 1976 until the sale of the pipeline by the Commonwealth Government to EAPL in 1994, a discounted weighted average tariff was set to recover costs on the basis of 100% debt financing at rates applicable to a Commonwealth statutory authority (rather than a commercial rate of return).[109]

Accordingly, the circumstances surrounding the 1994 sale of the MSP can be interpreted as the Australian Government incurring a windfall loss on its investment (taking into account the commercial risk inherent in the project). It is difficult to see how EAPL could suffer a windfall loss if the value of the ICB is set below the residual economic value, given the fact that EAPL paid $534 million for the MSP. Allowing a return to EAPL on an asset base of $1700 million would unjustifiable compensate EAPL for commercial risks borne by the previous owner and which were not reflected in the sale price.

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[107] EAPL submission, 5 November 2002, p. 12.

[108] ANAO, *Sale of the Moomba to Sydney Gas Pipeline*, Audit Report No. 10 1995-96, pp. 1-2.

[109] EAPL response to submissions, 17 August 2000, p. 3.

In the *Draft Decision* the Commission calculated a residual economic value as at 30 June 2000 based on the 1994 sale price of $442.8 million. In deriving this value, the Commission examined EAPL's actual cash flows and applied a commercial rate of return. However, the Commission gave little weight to this value, noting:

> To use the residual economic value as the initial capital base in the regulatory framework moving forward would amount to retrospective regulation to force the internal rate of return achieved by EAPL to the benchmark normal rate of return. This would be inappropriate. Moreover, the returns to EAPL have depended on its long term contractual arrangements with AGL. Normally when setting reference tariffs the Commission would have little regard to existing contractual arrangements. That is, high returns from a user under an existing contract could not be used to reduce the revenue that is to be recovered from other users through reference tariffs. Similarly, low returns from one user could not justify higher tariffs to other users. It could be argued that such a principle could be applied to the revenue earned to date by EAPL under its contractual arrangements with AGL. In this case, when establishing the value of the initial capital base, the Commission would disregard any excessive returns received by EAPL. To do otherwise could be considered a form of retrospective regulation.[110]

To some extent, this passage is inconsistent with the findings of the Court of Appeal in the Epic Decision. While the Court of Appeal did not endorse 'retrospective regulation', it clearly stated that past returns, tariffs and depreciation are potentially relevant and cannot simply be ignored in determining the ICB.

50 year asset life assumed in the past

In the *Draft Decision* the Commission noted that the historical financial accounts for the MSP suggested that assumptions of the pipeline's economic life ranged from 30 to 50 years.[111] The Commission gave considerable weight to the fact that EAPL had assumed an asset life of 50 years for depreciation purposes. The Commission applied a 50 year asset life to the ORC to determine a DORC value of $539 million. The Commission considered that this value (less deferred tax liabilities) formed an appropriate basis for the value of the ICB. The Commission commented that users would not be disadvantaged since they would not be required to support a double-up of depreciation, nor would EAPL be disadvantaged as the valuation approximated EAPL's investment in the MSP.

As mentioned earlier, the Commission's use of past rates of recovery of depreciation to determine a value for DORC has since received some criticism. The argument is that DORC is meant to be a forward-looking concept and hence past depreciation is an irrelevant consideration. Whether this is correct or not, section 8.10(f) makes it clear, however, that the level of recovery of depreciation since EAPL acquired the pipeline and EAPL's assumption of a 50 year asset life may still be relevant factors in the Commission's determination of the value of the ICB. That is, even if the DORC methodology demands that depreciation is based on the revised asset life, the Code does not prevent the Commission taking into account the basis upon which the pipeline has been depreciated in the past in order to determine an ICB. Applying this approach to the revised ORC of $1092.9 million results in an asset valuation of $559.3 million. This figure has been calculated on the basis of a 50 year asset life to 2000, and from

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110 ACCC, *Draft Decision: Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System,* 19 December 2000, p. 40.

111 ACCC, *Draft Decision: MSP,* p. 25.

then an 80 year life (the useful life proposed by EAPL in 2000 and accepted by the Commission in the *Draft Decision*).

Depreciation schedule in the face of a new entrant

In establishing the value of the ICB the Commission was also mindful of the loss of market share to the EGP.

In its original access arrangement (May 1999) EAPL proposed a value for the ICB equal to DORC determined on a straight line basis. However, for the depreciation charges that would apply over the access arrangement period EAPL proposed a kinked (accelerated) depreciation schedule. This would result in 62.5 per cent of the ICB being written off during the first half of the remaining life of the asset and 37.5 per cent over the second half. EAPL applied the kinked depreciation methodology only to depreciation going forward, not in determining the value of the ICB. In other words use of a kinked (accelerated) depreciation schedule leads to a faster write down of the ICB during the first half of the remaining asset life.

EAPL cited the risk of loss of volumes to the EGP as justification for an accelerated rate of depreciation. The difficulty with the manner in which EAPL applied its methodology, however, is that the accelerated depreciation schedule was proposed to be implemented **after** the EGP was commissioned.

Accelerated depreciation may be an appropriate strategy **prior to** the entry of the new firm into the market, not after the event. Accelerated depreciation allows early recovery of a substantial portion of the capital costs. Accordingly, prices would not have to increase at a later date to accommodate the loss of volumes in order for the service provider to recover its investment. Higher prices as a consequence of a fall in demand is not an outcome expected in a competitive market.

Accelerated depreciation would be an appropriate approach to depreciating the MSP prior to the entry of the EGP, not after the EGP was commissioned. In other words, a greater rate of depreciation would apply prior to the entry of the EGP, and a slower after the entry of the EGP. Determining a value for the ICB on the basis of a 50 year life to 2000, the year the EGP was commissioned, and an 80 year life subsequent to 2000 replicates this behaviour.

The Commission is not suggesting that EAPL originally assumed an asset life of 50 years for the MSP in order to achieve a faster return of capital in anticipation of the EGP being built in the future. Whether it did or not is largely irrelevant for the following reasons.

First, the Code requires the Commission to consider the basis on which tariffs have been (or appear to have been) set in the past, economic depreciation and historical returns. It does not require the Commission to explain the reasons for the service provider’s past pricing practices.

Second, whether a firm anticipates a new entrant and prices accordingly prior to the entry of a new firm is irrelevant after the event. If the firm failed to do so, in a competitive market it could not recover the loss of revenue (flowing from a loss of market share) from its remaining customers by increasing prices. It is a loss borne by the incumbent.

In conclusion, the Commission's approach of using a 50 year life to determine the value of the ICB and an 80 year life going forward replicates the performance of an incumbent firm that has recovered a substantial portion of its investment prior to the entry of a new firm.

Reasonable expectations under the prior regulatory regime (section 8.10(g))

Section 8.10(g) of the Code requires the Commission to take into account the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code. It is this criterion that EAPL has relied to justify its value for the ICB.

The prior regulatory regime governing the MSP

The regulatory regime that applied to the MSP prior to the commencement of the Code was established by Part 6 of the *Moomba-Sydney Pipeline System Sale Act 1994* (the MSPSS Act). A condition precedent of the head agreement between the Australian Government and AGL (the 51% Sale Agreement) was the establishment of a regulatory regime substantially in the form of the Interstate Gas Pipelines Bill, which was attached to the agreement as Schedule 6. Although that Bill was never legislated, its provisions were substantially incorporated in the MSPSS Act.

The MSPSS Act required the operator of the MSP to supply haulage services to anyone who sought those services on terms and conditions agreed to between the two parties. In the event that the two parties could not agree, either party could have notified the Commission[112] that an access dispute existed. The Commission would then have been responsible for determining the terms and conditions (including tariffs). In effect, the prior regulatory regime was based on a negotiate/arbitrate model.

The contractual rights of EAPL and AGL under the GTA were also preserved by the MSPSS Act. The MSPSS Act also required regulatory approval for associate contracts, except for the GTA.

The MSPSS Act did not empower the Commission with the authority to review reference tariffs published by EAPL. The Commission had a role in setting tariffs only if a dispute arose. Since no disputes were ever notified, the Commission made no assessment of the tariffs charged by EAPL.

The Epic Decision

In proposing a value for the ICB based on its 'reasonable expectations', EAPL has relied extensively on the findings of the Court of Appeal in the Epic Decision.

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[112] Under the provisions of the MSPSS Act the Commission's predecessors the Trade Practices Commission and the Prices Surveillance Authority had regulatory responsibility regarding third party access disputes and the monitoring of haulage charges and transactions that were not conducted at arm's length. The term Commission refers to both of its predecessors the Trade Practices Commission and the Prices Surveillance Authority.

In that matter, Epic argued that it had tendered $2.4 million to purchase the DBNGP on the understanding that it would be able to charge a tariff in the order of $1.00/GJ. The Court of Appeal summarised Epic's argument as follows:

> Epic had stressed to the Regulator, and stresses to this Court, its understanding from the sale information memorandum that tariffs after January 2000 would be in the order of $1 per GJ for the main Dampier to Perth transmission service…**It was in this understanding and expectation**, Epic contends, that it was able to offer to the State the purchase price of $2.407 billion for the DBNGP...[113] [Emphasis added]

While Epic described this as a 'regulatory compact', it did not suggest that this constituted a legally binding agreement which the regulator was bound to accept. Rather Epic submitted that for these reasons the regulator ought to have had regard to the price paid and reflected it in the value of the ICB.

The Court of Appeal held, however, that the documents relating to the tender process did not support Epic's understanding or expectation, finding that the material before the regulator did not establish that Epic agreed to buy the pipeline on the basis, or in the expectation, that tariffs would be in the order of $1.00/GJ from 1 January 2000.[114]

In addressing section 8.10(g) of the Code, the Court of Appeal stated that:

> By s 8.10(g) regard is to be had to the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code. The persons identified would appear to include users as well as the service provider. Insofar as it deals with the reasonable expectations of the service provider, it is the expectations under the regime that applied before the commencement of the Code that are material. Obviously, if that regime was more favourable for present purposes than the Code, the reasonable expectations of the service provider would be, relevantly, for a more favourable return on the investment of the service provider in the pipeline.[115]

Having discussed the meaning of the Code, the Court of Appeal considered the application of the Code to the facts before it, starting with the question of:

> …whether the price paid by Epic for the DBNGP represented a sound commercial assessment of the value of the pipeline in the circumstances that prevailed at the time of the purchase and which were then reasonably anticipated, **or reflected the reasonable expectations of Epic under the regulatory regime that applied to the DBNGP prior to the commencement of the Code**.[116] [Emphasis added]

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113 [2002] WASCA 231, par 195.

114 [2002] WASCA 231, par 196-200.

115 [2002] WASCA 231, par 169.

116 [2002] WASCA 231, par 188.

This passage indicates that one of the issues being considered by the Court of Appeal was Epic's reasonable expectations under section 8.10(g) of the Code. Of significance of this part of the Court of Appeal's judgment is that it examined Epic's alleged expectations in terms of what it was led to expect by the tender process and the regulatory regime that applied at the time. It was not concerned simply with what Epic's expectations were, but rather whether it had been led to those expectations by the regulatory regime that applied to the pipeline at that time. This distinction is drawn out in the Epic Decision where the Court of Appeal stated:

> In Schedule 30 to the sale contract Epic identified $1.00 per GJ as its proposed tariff rate for the primary Dampier to Perth service. This had no contractual force, however, for purposes relevant to the determination of a tariff under the Code. Nor was the State in any way even committed to supporting such a tariff before the Regulator. **In essence, it was a statement by Epic of what it hoped to achieve under the Code, the risk lying with Epic whether it did so**.[117] [Emphasis added]

The Court of Appeal appears to have applied section 8.10(g) by examining not merely Epic's expectations, but whether those expectations were brought about by or underpinned by the regulatory regime that applied at the time. This is the argument put forward by EAPL when it states that its reasonable expectations formed part of the sale agreement with the Australian Government and were underpinned by the prior regulatory regime.

EAPL's purported 'reasonable expectations' are based on two factors: contract prices and volumes under the GTA; and published prices and volumes in relation to other parties. EAPL stated that the NPV of cash flows under the GTA alone was $586 million in 1994.[118]

EAPL submitted that, as no access disputes were lodged concerning EAPL's published tariffs, then those prices for volumes in excess of GTA volumes were consistent with its reasonable expectations. The Commission does not agree with this argument. The regulatory regime that existed under the 1994 MSPSS Act only provided that, in the event of an access dispute, the Commission had the power to arbitrate under section 80. The regime offered no other guarantees to EAPL in relation to volumes or prices.

Since the regulatory regime did not require a prospective user to acquire access to the pipeline, it could not have been reasonable for EAPL to expect that the regulatory regime would deliver certain volumes over and above existing contracted amounts. Similarly, the fact that users may have agreed to use the pipeline at tariffs similar to EAPL's published prices did not mean that future users would be bound to the same tariffs. Future users may have agreed to EAPL's published rates, but if they did not the Commission had the power to arbitrate. As this power was never used, no statements on the reasonableness of the MSP tariffs were ever made by the Commission. Accordingly, it could not have been reasonable for EAPL to expect that the regulatory regime would deliver specific prices for future users.

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117 [2002] WASCA 231, par 199.

118 EAPL submission, 14 March 2001, p. 15.

EAPL submitted that the best indication of its reasonable expectations was the NPV of its expected cash flows as at 1997/1998. Moreover, EAPL submitted that the inclusion of the regulatory regime provisions as a condition precedent of the sale agreement supported its argument that its reasonable expectations formed part of its agreement with the Australian Government.

The Commission considers that the connection between EAPL's reasonable expectations and the agreement with the Australian Government is untenable. As mentioned above, the prior regulatory regime provided no guarantees concerning tariffs or volumes (except under the GTA). In the Commission's view, EAPL has simply put forward what it considers to be its reasonable expectations prior to commencement of the Code without specifically linking it to the prior regulatory regime.

Section 8.10(g) of the Code does not merely require the regulator to take into account the mere expectations that a person held prior to the commencement of the Code. The provision makes express reference to the reasonable expectations of a person **under the regulatory regime** that applied prior to the commencement of the Code. It draws a specific link between a person's expectations and the prior regulatory regime. In other words section 8.10(g) appears to be concerned with reasonable expectations brought about by, or, to use EAPL's words, underpinned by the regulatory regime that applied prior to the Code.

In relation to published prices outside of the GTA, EAPL's forecasts were neither based on, nor somehow underpinned by, the regulatory regime as set out in the MSPSS Act. There is nothing in this regime that could have led EAPL to reasonably expect those tariffs would continue to apply to prospective users into the future. These tariffs were not determined or approved by the regulator or preserved into the future under that regime. EAPL's 'reasonable expectations' are similar to the Court of Appeal's characterisation of Epic's expectations in that they appear to reflect what EAPL hoped to achieve, rather than reflecting any outcome that was guaranteed under the previous regime.[119]

The case is slightly different in relation to forecasts based on volumes and prices set out in the GTA, in that the regulatory regime that existed prior to the Code preserved existing contractual arrangements between AGL and EAPL. It is arguable that it would have been reasonable for EAPL to expect that, under the prior regime, the volumes and prices under the GTA would continue for the life of that agreement (to 31 December 2016).

However, there are two reasons why these tariffs should not form the basis for determining the ICB. First, any expectation by EAPL that its existing contracts would be preserved is satisfied by section 2.25 of the Code, which states that the regulator must not approve any provision of an access arrangement that would deny any party an existing contractual right (other than certain exclusivity rights). Further, there is nothing in the prior regime that preserves these prices beyond the life of this agreement.

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119 [2002] WASCA 231, par 199.

Second, the GTA no longer exists, but was replaced in June 2000 by the GTD, which EAPL submitted to the Commission for approval as an associate contract. The GTD itself is not a contract for the supply of transportation services. It is framework agreement setting out the broad relationship between EAPL and AGLWG to 31 December 2016 and establishes the basis on which EAPL and AGLWG will enter into service contracts. The GTD provides that tariffs will be set according to reference tariffs under an access arrangement approved by the Commission and will move in line with reference tariffs as approved from time to time. The GTD also affords AGLWG with a contractual right to any lower tariff that EAPL negotiates with a third party. The Commission questions the appropriateness of basing the value of the ICB on the NPV of cash flows under the GTA for current regulatory purposes, when the current regulatory regime itself was a significant factor that led to the termination of the GTA.

In conclusion, the Commission considers that EAPL's proposal does not correctly apply section 8.10(g). Section 8.10(g) does not simply require that the regulator take into account the expectations that persons held prior to the commencement of the Code. Rather, the provision makes express reference to the reasonable expectations of a person **under the regulatory regime** that applied prior to the commencement of the Code. It draws a specific link between a person's expectations and the prior regulatory regime. That is, the Commission considers that section 8.10(g) is concerned with reasonable expectations brought about by, or to use EAPL's expression 'underpinned' by, the prior regulatory regime. EAPL's proposed value for the ICB is merely representative of what EAPL hoped to achieve in terms of its cash flows at a particular point in time.

The economically efficient utilisation of gas resources (section 8.10(h))

Section 8.10(h) of the Code requires the Commission to have regard to the impact on the economically efficient utilisation of gas resources. In the Epic Decision the Court of Appeal stated that this requirement contemplates the principles of economic efficiency and does so in the broader context of gas resources, rather than the more limited focus of gas pipelines.

The Commission considers that the economically efficient utilisation of gas resources can best be achieved by setting a value for the ICB that is consistent with the objectives in section 8.1 of the Code. In particular, the asset value should allow the opportunity for recovery of efficient costs, replicate the outcomes of a competitive market and not distort investment decisions in gas transportation or upstream and downstream gas industries.

Comparability with the cost structure of competing pipelines (section 8.10(i))

Section 8.10(i) of the Code requires the Commission to consider the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the pipeline in question). In the Epic Decision the only comment made by the Court of Appeal on this provision was that it has some consistency with economic theory.

A valuation based on DORC is consistent with section 8.10(i), as a valuation in excess of DORC could potentially lead to uneconomic by-pass.

Also of relevance in this instance is the EGP which serves some of the markets, Sydney and Canberra, also served by the MSP. The owner of the EGP, DEI, was critical of the Commission's proposed reference tariffs and the value of the ICB underlying those tariffs. In DEI's opinion, the Commission did not have sufficient regard to the fact that the MSP faces direct competition from the EGP. DEI also submitted that it would not be able to sustain pricing at the level of tariffs proposed by the Commission in its *Draft Decision*.

DEI referred to the Commission's *Draft Decision*:

> …if gas transportation was a contestable market, it could be expected that tariffs and revenues would tend to follow the costs faced by a new entrant.[120]

DEI stated that the reference tariff proposed by the Commission in its *Draft Decision* is equivalent to about half the average cost ($0.86/GJ) to transport gas from Longford to Sydney via the EGP. Hence DEI seems to be relying on section 8.10 (i) of the Code, which requires the regulator to take into account the comparability of the cost structure of potentially competing pipelines, to support its argument that the Commission should have regard to its average cost of $0.86/GJ.

DEI also submitted that the reduction in MSP tariffs by EAPL from 1 July 2000 was a competitive response to the entry of the EGP. At that time EAPL reduced its tariff to the Sydney market from $0.71/GJ to $0.66/GJ. While not suggesting that reference tariffs on the MSP should be set at $0.86/GJ, DEI did submit that the Commission should adopt EAPL's current published tariffs as the access arrangement reference tariffs. DEI described EAPL's published tariffs as the current 'market prices', and submitted that this represented the outcome that would occur in a competitive market as the price reduction was a result of the entry of the EGP.

To the extent that DEI would suffer a financial detriment if tariffs are below its 'costs' of $0.86/GJ,[121] clearly the financial detriment to DEI would be minimised by setting reference tariffs at EAPL's current published tariffs rather than at some lower level.

The Commission does not consider that the arguments submitted by DEI are sufficiently robust to have a significant bearing on the Commission's determination of the ICB for the MSP. DEI submitted that its average cost is $0.86/GJ. It is not unusual for a new pipeline, such as the EGP, to have high initial average costs, which would later decrease in line with market growth. This does not mean, however, that the regulated tariffs of an established pipeline, such as the MSP, should be set to reflect the average costs of a new pipeline.

The costs of a new entrant may provide a yardstick for the upper limit of the valuation of the incumbent firm. Any higher valuation for the incumbent's assets may result in users by-passing the incumbent in favour of the new entrant. It does not follow, however, that the valuation of the incumbent's assets should be increased in order to reflect the costs of the new entrant.

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[120] ACCC, *Draft Decision: MSP,* p. 25.

[121] The Commission has made no assessment of whether $0.86/GJ is reflective of the costs of the EGP.

The price paid for any asset recently purchased by the service provider (section 8.10(j))

Section 8.10(j) of the Code requires the Commission to consider the price paid for any asset recently purchased by the service provider and the circumstances of that purchase in establishing the value of the ICB.

The price paid by APT to acquire all the shares in EAPL is discussed earlier in the discussion on section 8.10(c) of the Code.

In the Epic Decision the Court of Appeal commented that this Code provision required consideration of: the circumstances of the purchase, including reasonable commercial judgment as to value; the extent to which the price may have been influenced by expectations of monopoly profit; and the careful scrutiny of transactions between related entities or transactions that involved motivations unrelated to value.

The Court of Appeal also noted similarities in the factors that are relevant to sections 8.10(c), (d) and (j). In relation to section 8.10(d) the Court of Appeal held that the actual investment in the pipeline was a relevant factor for a regulator to take into account in setting the value of the ICB. The actual investment may be relevant notwithstanding that it may embody monopoly profits, although reckless or commercially unsound acquisitions should not be accepted for this purpose.[122]

The Court of Appeal noted that the price paid by Epic represented its investment in the DBNGP. It also stated that it may be in the service provider's legitimate business interests (section 2.24(a)) to recover its investment, even if this investment included monopoly returns. Moreover, a valuation of the ICB that denied the service provider the opportunity to recover its investment may have a detrimental impact on future investment in the gas pipeline industry. The findings of the Court of Appeal in the Epic Decision suggest that a valuation based on purchase price need not be inconsistent with section 8.1(a) of the Code ('efficient costs', which the Court of Appeal suggested need not be limited to forward-looking costs) and section 8.1(b) ('replicating a competitive market' which could include some monopoly returns).

The Commission has some concerns with setting the value of a regulatory asset base equal to the price paid by the service provider to acquire the asset from the previous owner. Such a policy has the potential for the acquirer to pay excessive prices for assets in the knowledge that the price it pays will be recoverable through tariffs approved by the regulator. This risk may be mitigated, however, where the purchase was the result of a competitive process (such as a tender).

While not suggesting that the price paid by APT was excessive, the Commission notes, however, that the acquisition was not subject to competitive pressures. Accordingly, the Commission does not consider that the price paid by APT should form the basis of the ICB. Nevertheless, the Commission acknowledges that it is a factor to which it should have regard, as, in accordance with the Epic Decision, this represents EAPL's

122 [2002] WASCA 231, par 172-173.

investment in the pipeline. For the reasons stated, however, this factor has been given little weight.

EAPL submitted that the Commission should have regard to the 'DAC of $459 million'.[123] This figure would be better described as a depreciated sale price (based on historical costs). The value of $459 million was calculated by the Commission in the *Draft Decision* by taking account of the 1994 sale price, capital expenditure since then and accounting depreciation to date.

The Commission has calculated an alternative value at $533.4 million, which indexes the 1994 sale price and capital expenditure to date by inflation to produce a value in today's prices. Depreciation is on the basis of a 50 year asset life to the year 2000.

Other factors the regulator considers relevant (section 8.10(k))

Section 8.10(k) of the Code allows the regulator to take into account any other matters that it considers relevant. In this regard the Commission considers that a valuation consistent with the 'hypothetical new entrant test' (HNET) is a relevant consideration.

Hypothetical new entrant test

The issue of what level of tariffs would apply in a competitive market in the context of the MSP arose in relation to the NCC's consideration of EAPL's application for revocation of coverage of the MSP. In December 2001 the NCC made its draft recommendation to the Minister that EAPL's application for partial revocation of coverage of the MSP should not be approved and that the MSP should remain a covered pipeline under the Code.[124]

In reaching this conclusion the NCC relied on material contained in the Commission's *Draft Decision* on EAPL's proposed access arrangement. In particular the NCC noted that tariffs proposed in the *Draft Decision* were up to 40 per cent less than EAPL's existing tariffs. The NCC concluded that this was evidence that EAPL had substantial market power to distort competition in dependent upstream and downstream markets.

In response to the NCC's draft recommendation, EAPL submitted to the NCC a report by the Network Economics Consulting Group (NECG). NECG was critical of the NCC's use of the Commission's tariff calculations and its conclusion that the difference between the MSP's actual tariffs and the Commission's proposed tariffs was evidence that EAPL had market power. NECG argued that tariffs calculated using the principles of the Code were somewhat irrelevant as an indicator of contestable market prices, as the Code did not apply the HNET, which NECG argued was the correct benchmark for determining contestable prices and the extent to which a firm is exercising market power.

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123 EAPL submission, 5 November 2002, p. 23.

124 In its final recommendation the NCC affirmed its draft decision that the MSP should remain a covered pipeline.

The HNET is a means of estimating a hypothetical 'competitive' market price for an industry that is not competitive. Underlying assumptions of the HNET are:

- the hypothetical new entrant would completely displace the incumbent service provider; and
- the hypothetical new entrant would operate efficiently and invest optimally.[125]

NECG concluded that the annual revenue requirement of a hypothetical new entrant was about $89 million, in contrast to the Commission's proposed revenue requirement of $59 million in its *Draft Decision*. NECG stated that EAPL's current tariff of $0.66/GJ (for Moomba to Sydney) was more consistent with the HNET revenue stream than the tariff of $0.43/GJ proposed by the Commission in its *Draft Decision*.

Underlying NECG's conclusion was the assumption that the HNET tariffs should be based on current volumes for the MSP. Of importance in this regard is that MSP volumes were at a low point following a loss of volumes to the EGP.

The Commission considered that the analysis undertaken by NECG had some relevance to its assessment of the tariffs proposed by EAPL for the MSP. Accordingly, the Commission engaged the services of NERA to critique the NECG report.

NERA defined the HNET as the maximum price that an incumbent could charge if there were a credible threat of new entry. In other words what is the maximum price that the incumbent could charge its customers if they had the option of negotiating as a coalition with a new entrant.

While NERA agreed that the HNET was an appropriate benchmark to determine a hypothetical contestable price in a market that was not in reality contestable, it was critical of the manner in which NECG applied the test to the MSP. In particular, it was critical of NECG's use of firm-specific volumes (volumes flowing through the MSP) rather than market volumes (MSP volumes plus EGP volumes).

NERA stated that if the HNET, as proposed by NECG, was applied prior to the entry of the EGP, the corresponding HNET tariffs would have been lower than today's HNET tariffs, given the difference in volumes. According to NERA, NECG's approach created an anomaly as the entry of another firm should not result in the HNET price increasing (that is competition should not lead to higher prices).

NERA argued that it would be more efficient for one pipeline to supply the total NSW/ACT demand than two pipelines (the MSP and EGP). Hence, according to NERA the correct methodology for applying the HNET would be to determine the cost of constructing an optimal pipeline to supply the whole market and use total market volumes (not firm-specific volumes) to determine tariffs.

NERA concluded that the hypothetical new entrant price was about $0.51/GJ, which was the maximum price that would be expected to be observed in a competitive market.

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[125] NECG, *Critique of ACCC draft decision on MSP tariff in the context of the hypothetical new entrant price,* 11 February 2002, p. 11.

This tariff was significantly below EAPL's current tariffs ($0.66/GJ for Moomba to Sydney). On this analysis the current Moomba to Sydney tariff of $0.66/GJ is approximately 30 per cent higher than the HNET tariff. Furthermore, NERA concluded that the application of the HNET supported the assertion that EAPL was exercising market power and charging monopoly prices.

In response to NERA's report, NECG reiterated its contention that the appropriate approach is to consider the total revenue and costs of the MSP, rather than unit costs based on total market volumes. NECG submitted that a consequence of reference tariffs based on total NSW/ACT volumes would be the under recovery of EAPL's long term costs.

The implication of this argument is that the Commission would determine reference tariffs on the basis of a level of volumes other than forecast volumes for the MSP. However, for the purposes of the current consideration the Commission has used forecast volumes to determine tariffs which the Commission considers will provide EAPL with an opportunity to recover its costs.

In this *Final Decision* the Commission has discussed the apparent anomaly of loss of volumes to the EGP putting upwards pressure on tariffs, contrary to the objective of replicating the outcomes of a competitive market. In response to the NERA report, NECG contended that an increase in tariffs in the transportation of gas following the entry of a new firm was not inconsistent with the outcomes of a competitive market if the overall cost of delivered gas (gas supply plus transportation) decreased as a result of increased competition in upstream markets. In the Epic Decision the Court of Appeal noted, however, that the Code objective of replicating the outcomes of a competitive market was a reference to the gas transportation component of gas delivery (rather than the total cost of supplying gas to markets).

In relation to the transmission of gas on the MSP, of significance is the point raised by NERA that the application of the HNET to the MSP, as presented by NECG, prior to the commissioning of the EGP would have resulted in lower tariffs than those following the commissioning of the EGP. According to NERA, such an outcome is anomalous as the entry of a new firm should not lead to an increase in the HNET price.

Although the Commission has not applied the HNET test to determine reference tariffs, it considers that the HNET tariff calculated by NERA is a relevant factor in its consideration of the tariffs that would achieve the Code objective of replicating the outcomes of a competitive market (section 8.1(b)). Tariffs determined in accordance with the HNET (as calculated by NERA) are broadly consistent with an ICB of $559.3 million. While the Commission does not consider it appropriate to determine the ICB by reference to the HNET, the Commission considers that this analysis can be used to test the appropriateness of tariffs that result from a particular ICB value.

Interpretation of section 8.1 objectives

The Court of Appeal gave some guidance to the interpretation of the objectives expressed in section 8.1 of the Code. This section of the *Final Decision* considers each of these objectives in relation to the ICB of the MSP. Section 8.1 sets out the objectives which the reference tariff and reference tariff policy should be designed to achieve. The Code recognises that these objectives may conflict. The establishment of the value of the ICB is one parameter that comprises the reference tariff and reference tariff policy. While the Commission is required to evaluate the reference tariff and reference tariff policy with reference to the section 8.1 objectives, not all the objectives will be relevant to every component of the reference tariff policy.

Efficient costs (section 8.1(a))

Section 8.1(a) provides that a service provider should be given the opportunity to recover its efficient costs. While noting that there was no settled meaning for the notion of 'efficient costs', the Court of Appeal concluded that the reference to efficient costs in section 8.1(a) was a reference to the economic concept of efficient, namely productive, allocative and dynamic efficiency.

The Court of Appeal left open the question of whether this objective is confined only to forward-looking costs, as submitted by the WA Regulator and Alinta Gas. While noting that the interpretation of efficient costs as a forward-looking concept was supported by economic theory, the Court of Appeal suggested that this was a decision for the regulator. However, the Court of Appeal did note that this objective is referring to efficiency as it relates to services (not the market generally) and the recovery of costs over the life of the pipeline. The Court of Appeal appeared to leave open the possibility that the recovery of efficient costs, for the purposes of section 8.1(a), included the recovery of past investment, stating that this was a matter for the regulator.[126]

The Court of Appeal also noted that this objective sets neither a ceiling nor a floor. That is, the objective is concerned with neither a revenue stream that recovers no more than efficient costs nor one that covers at least efficient costs.[127] This suggests that, depending on the weight given to various factors, the value for the ICB ultimately adopted could be either above or below the value suggested by section 8.1(a).

The Court of Appeal observed that 'the DAC and DORC methodologies have an acceptability for the purposes of the concept of economic efficiency.'[128] Interpretation of efficient costs as a forward-looking concept favours DORC as the appropriate methodology for determining the value of the ICB. However, as noted above, the Court of Appeal does not appear to limit the recovery of efficient costs to forward-looking costs. The interpretation adopted by the Court of Appeal would allow the value for the ICB to be set in accordance with other methodologies.

When the Australian Government owned the MSP, tariffs were set on the basis of cost recovery only, and not with a view to recover an allowance for the inherent commercial risks involved. For this reason the Commission does not consider that DAC is a very useful parameter in its consideration of the recovery of efficient costs over the life of the pipeline. Likewise a residual economic value of $1700 million also has little relevance. A value for the ICB set on this basis would compensate EAPL for the

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126 [2002] WASCA 231, par 141.

127 [2002] WASCA 231, par 141-142.

128 [2002] WASCA 231, par 176.

commercial risk borne by the previous owner and which was not reflected in the 1994 sale price of $534 million.

Given the Court of Appeal's interpretation of section 8.1(a) it would be appropriate for the Commission to consider the recovery of efficient costs from the time that EAPL acquired the MSP from the Australian Government in 1994. While the Commission has made no assessment of the efficient costs of the MSP in 1994, the ANAO report provides some guidance. The ANAO noted:

> The Consultant also calculated a value that was described as the 'intrinsic' value of the pipeline. This was based on the cost of building a pipeline to supply the needed capacity and depreciated to replicate the age of the existing pipeline (term the 'scaled-down replacement cost', which was provided by TPA). The rationale for this approach was that no buyer would pay more for the pipeline than the cost of building a replacement which would have at least a twenty years longer life expectancy. This intrinsic value was estimated in July 1993 to be $561 million under the assumption of a 50 year life for the current pipeline, although a revision in December 1993 was as low as $500 million.[129]

While the price paid by EAPL for the MSP may not have been a direct response to these estimated values, the Commission notes that the 1994 sale price of $534 million is broadly consistent with the scaled-down replacement cost as estimated in 1993. While the sale price would be inconsistent with the economic concept of forward-looking efficient costs, it would be consistent with the Court of Appeal's interpretation of efficient costs under section 8.1(a) of the Code which could include considerations of past costs.

A further significant factor is the useful asset lives assumed for the pipeline. In the past EAPL has assumed an asset life of 50 years, whereas the current life is assumed to be 80 years. It is on this basis that the Commission has determined the value of the ICB (50 years) and future depreciation charges (80 years). If the useful life of an asset is reviewed it is appropriate that costs should be recovered over the new assumed life of the asset.

However, a change to the assumed life of an asset should not necessarily signal a revaluation of the asset base. Revaluing an asset upwards to reflect any extension to the useful life of an asset would ultimately allow the service provider to recover more than its efficient costs over the life of the asset. Accordingly, the Commission has concluded that this objective is most likely to be satisfied if the ORC of the MSP is depreciated assuming an asset life of 50 years until 2000, and a life of 80 years from 2000 onwards.

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[129] ANAO, *Sale of the Moomba to Sydney Gas Pipeline*, Audit Report No. 10 1995-96, p. 25.

Replicating a competitive market (section 8.1(b))

Section 8.1(b) states that the reference tariff and reference tariff policy should be designed to achieve the objective of replicating the outcome of a competitive market. The Court of Appeal noted that in this provision the Code contemplates a competitive market in the field of gas transportation, notwithstanding that the Code is based on the premise that gas transportation is a monopoly situation and construction of another pipeline would be uneconomic. The Court of Appeal stated:

> The objective seems to necessitate the application of economic methods and theory, albeit to replicate the outcome of a workably competitive market, because the achievement of competition in fact is not possible.[130]

The Court of Appeal concluded that the reference to a 'competitive market' was a reference to 'workable competition' (as opposed to the economic concept of perfect competition). That is, it refers to a market in which no firm has a substantial degree of market power. However, the Court of Appeal also noted the that expert evidence suggested that a workably competitive market may tolerate some degree of market power, even over a prolonged period. In addition, the Court of Appeal noted the complementary nature of the objectives in sections 8.1(a) and 8.1(b) in view of the interrelationship between economic efficiency and competition in a market:

> The underlying theory and expectation of economists, however, is that with workable competition market forces will increase efficiency beyond that which could be achieved in a non-competitive market, although not necessarily achieving theoretically ideal efficiency.[131]

The Court of Appeal observed that over time the revenue earned by a service provider in a workably competitive market would approximate the efficient costs of delivering the service. It concluded that this helped to confirm that efficient costs and the outcomes of a workably competitive market are not capable of precise or certain calculation, but at best can only be approximated.[132]

A valuation based on DORC, which represents the forward-looking efficient costs of delivering services, would be consistent with section 8.1(b) of the Code. In theory, prices based on DORC represent the maximum that would be observed in a competitive market. Prices in excess of DORC would result in customers by-passing the incumbent in favour of a new entrant. For this reason, valuation methodologies that produce values for the ICB substantially in excess of DORC, such as EAPL's proposed residual value of $1700 million, would be less likely to produce outcomes that replicate a competitive market.

Also relevant to this Code provision is the loss of market share to the EGP. For access arrangement purposes EAPL's proposed volumes are lower than what they otherwise would have been if the EGP had not been constructed. As reference tariffs are typically determined by dividing forecast costs by forecast volumes, reference tariffs would be higher than what they would otherwise have been in the absence of the EGP. This outcome would not replicate the outcomes expected from a competitive market.

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130 [2002] WASCA 231, par 127.

131 [2002] WASCA 231, par 128.

132 [2002] WASCA 231, par 143.

Accordingly, in determining the value for the ICB of the MSP the Commission has had regard to the HNET tariff of $0.51/GJ as determined by NERA since it represents the price that would be observed in a hypothetical contestable market in a market that is not contestable.

Given the length of time that the MSP was under Government ownership and the policy of the Government not to seek a commercial return, the Commission considers that the DAC of $100 million is of little assistance in deriving tariffs that would replicate the outcomes of a competitive market.

Although the Commission does not believe that section 8.10(g) requires it to take into account EAPL's proposed value for the ICB of $779 million (based on its 'reasonable expectations'), it has considered this proposal in the context of section 8.1(b) of the Code. As described above, this value is based, to a significant extent, on the prices in the GTA. However, the GTA did not reflect the result of a competitive, arm's-length, commercial transaction. Rather it was an agreement between two related parties. Moreover, AGL held a strong bargaining position as it had a right of refusal over any sale of the pipeline. As well as the revenue stream inherent in the GTA, EAPL's 'reasonable expectations' valuation was also based on the NPV of revenues from other parties. Underpinning the forecast revenue stream were forecast volumes in excess of those EAPL has now proposed as part of its access arrangement. EAPL stated that

> the most persuasive evidence in support of the reasonableness of those assumptions [of volumes] is the fact that the anticipated loads did not vary significantly from those that have actually occurred **(after taking into account the loss of load to the EGP which could not have been reasonably anticipated by EAPL)**. Since the volume assumptions have been supported by actual demand, they are the appropriate basis for determining reasonable expectations. [133] [Emphasis added]

The Commission disputes that EAPL could not have anticipated any loss of load to the EGP in 1997, as the EGP was mooted by BHP and Westcoast Energy as early as 1996.[134] Nevertheless, whether or not EAPL anticipated the loss of load is essentially irrelevant when considering the objective of replicating the outcome of a competitive market (section 8.1(b) of the Code). In a competitive market a firm that fails to anticipate a fall in demand and price accordingly prior to that fall would not be able to recover the loss of revenue from its remaining customers.

Consequently, the Commission does not consider that a value for the ICB which is underpinned by old volume forecasts that are no longer applicable would replicate the outcome of a competitive market. In a competitive market a reduction in volumes would signal a reduction in the value of a firm's assets. Alternatively, were the value of the ICB to be based on the NPV of expected cash flows prior to the introduction of the current regulatory regime, then it would be reasonable that reference tariffs should be based on the higher volumes that underpin that valuation, rather than the volumes now proposed by EAPL.

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133 EAPL submission, 5 November 2002, p. 10.

134 See Dept of Industry, Science and Resources, Australian Energy News issue 2, *Developing a National Energy Market,* December 1996, p. 6, at http://www.isr.gov.au/resources/netenergy/aen/aen2/2market.html.

Given that the sale of the MSP by the Government to EAPL was not the result of competitive process, the Commission does not consider that the 1994 sale price would necessarily have represented a value that replicated the outcomes of a competitive. The Commission has drawn the same conclusion with respect to the market value, based on the 2000 float, put forward by EAPL.

Safe and reliable operation of the pipeline (section 8.1(c))

Section 8.1(c) states that the reference tariff and reference tariff policy should be designed to achieve the objective of ensuring the safe and reliable operation of the pipeline. The Court of Appeal interpreted this provision as requiring that the revenue stream should be sufficient to meet the safety and reliability needs as and when it is necessary.[135] This interpretation suggests to the Commission that this objective is directed more at operating expenses and capital expenditure with little direct relevance to the establishment of the value of the ICB.[136]

Investment decisions should not be distorted (section 8.1(d))

The objective of section 8.1(d) of the Code is that investment decisions in pipeline transportation services and upstream and downstream industries should not be distorted by the reference tariffs or the reference tariff policy.

In the Epic Decision the focus was on the first limb of this objective, that investment in pipeline transportation systems should not be distorted. The Court of Appeal noted, however, the need for the regulator to consider the consequences for upstream and downstream industries also.

A valuation based on DORC would satisfy this criterion if it were confined to future investment. However, the Court of Appeal dismissed submissions that this condition would be met by setting tariffs solely in accordance with the forward-looking efficient costs of delivering reference service, without having regard to past investment decisions.

While acknowledging that the theory of economic efficiency would suggest that past investment decisions be ignored, the Court of Appeal suggested that the broader public interest would require past investment decisions to be taken into account. To ignore past investment decisions, according to the Court of Appeal, may have adverse effects on necessary future investment. The Court of Appeal observed that it would be consistent with the objective reflected in section 8.1(d) if the regulator were to take into account the actual investment of the owner in the pipeline when that investment decision was made prior to the introduction of the Code. It stated:

> ...it would appear that the outcome under the Code of an investment decision in a pipeline made before the introduction of the Code…would not be irrelevant to the Regulator's deliberations, under s 8, including the establishment of the initial Capital Base.[137]

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[135] [2002] WASCA 231, par 146.

[136] Nevertheless, a plausible interpretation is that a value of the ICB that is set too low, for example below the level of the service provider's investment, may encourage the service provider to cut costs to increase its return on its investment to the detriment of the integrity and safety of the pipeline.

[137] [2002] WASCA 231, par 154.

This may include decisions involving an expectation of above normal profits, but not 'reckless, mistaken or highly speculative' investment decisions. The policy of this objective is to ensure that socially beneficial investment in pipeline assets is not discouraged. The Court of Appeal noted:

> If future investment in significant infrastructure … is to be maintained and encouraged, as the public interest requires, regard seems to be required to the need for both existing and potential investors to have confidence that the very substantial long term investment decisions which are required, and which were sound when judged by the commercial circumstances existing at the time of the investment, are not rendered loss-making, or do not result in liquidation, by virtue of **future governmental intervention**.[138] [Emphasis added]

This indicates that the Court of Appeal considered the objective to be aimed at preventing potential investors from being discouraged from investing in future beneficial projects by a Government acting in a manner contrary to the impression it had earlier projected.

In circumstances in which ownership of a pipeline has not changed hands, the owner's investment in the pipeline is represented by the original capital costs plus capital expenditure and less depreciation. Accordingly, DAC would be normally be a relevant consideration when addressing this criterion. The matter is complicated in a case where ownership has changes hands, such as EAPL's purchase of the MSP in 1994.

The 1994 sale price of $534 million is relevant to establishing the ICB and section 8.1(d) of the Code. First, because in accordance with the Epic Decision, it represents the amount of EAPL's investment in the pipeline. Second, the transaction occurred prior to the introduction of the Code.

As noted earlier, however, the Commission does not consider that the sale price alone is a sound basis for determining the value of the regulatory asset base. Nevertheless, the Commission notes that the value for the ICB proposed by the Commission, $559.3 million, will give EAPL the opportunity to recover the price it paid for the pipeline. A lesser valuation, such as DAC of $100 million, would deny EAPL that opportunity.

The Commission also considered whether EAPL's proposed valuation of $779 million satisfied section 8.1(d). In support of its proposed value for the ICB EAPL stated that:

> … any ICB which did not reflect the deal which was reached between the Government and EAPL at the time, including the reasonable expectations under that regime, would distort the basis on which that investment had been made.[139]

EAPL further submitted that:

> … to establish an ICB at any lesser valuation is to respectively confiscate the benefit to EAPL of the deal attained in the privatisation process, a confiscation directly in contrast to the view held by the court in the Epic Decision.[140]

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138 [2002] WASCA 231, par 149.

139 EAPL submission, 5 November 2002, p. 20.

140 EAPL submission, 5 November 2002, p. 21.

In considering this proposal it is useful to distinguish the facts of the Epic Decision from the arguments put forward by EAPL. In essence, Epic argued that the value of the ICB for the DBNGP should be in accordance with the price it paid for the pipeline. On the other hand EAPL argued that its investment would be distorted if the value of the ICB is set a level below $779 million, which is considerably higher than what EAPL paid when it purchased the pipeline. On the assumption that the price paid by EAPL was not a reckless, commercially unsound or speculative decision, a case could be argued that setting a value below that price (after allowing for capital expenditure and depreciation to date) would distort its investment decision, since EAPL would not recover the price it paid.

Likewise it could be reasonably argued that setting a value for the ICB in excess of what EAPL paid would distort its investment as EAPL would receive a windfall capital gain. Accordingly, the Commission does not agree with EAPL's arguments that its investment would be distorted if the ICB is valued at less than $779 million. Moreover, the Commission does not agree with EAPL's interpretation that the findings of the Court of Appeal support EAPL's submission that a valuation less than $779 million would confiscate the benefit to EAPL of the privatisation deal 'in contrast to the view held by the Court of Appeal in the Epic Decision.'

The Code does not require the Commission to determine the ICB in accordance with the mere hopes or expectations of the service provider as to its future revenue. The mere fact that a service provider acquired an asset on favourable terms does not, by itself, require the regulator to ensure that the benefits of that transaction are preserved into the future. There are a range of factors under section 8 of the Code that must be considered and balanced in order to arrive at a value for the ICB. Some of these, such as section 8.10(g) and section 8.1(d) may, in certain cases, point towards the adoption of an ICB that provides the returns anticipated by the service provider. However, other factors, such as 8.1(a) and (b) may justify an ICB that will provide returns less than those anticipated by the service provider. Weighing these factors is the responsibility of the regulator.

The second limb of section 8.1(d) (not distorting investment in upstream and downstream industries) can best be met if the section 8.1(a) is also satisfied. That is, tariffs should be based on efficient costs. In accordance with the Epic Decision, the concept should not be confined to forward-looking efficient costs. Tariffs based on historical costs, if efficient at the time, would also satisfy section 8.1(d). This suggests that values between DAC and DORC would be consistent with this criterion, but that a value as high as the residual economic value ($1700 million) submitted by EAPL would not.

Efficiency in the level and structure of tariffs and incentives (sections 8.1(e) and 8.1(f))

The objective of section 8.1(e) of the Code is efficiency in the level and structure of the reference tariff. Section 8.1(f) requires the reference tariff policy to provide for incentives to the service provider to reduce costs and to develop the market for reference and other services. The Court of Appeal did not provide any significant guidance on these objectives other than to note that the concept of 'efficiency' relates to the concept of economic efficiency.

The Commission considers that the objective contained in section 8.1(e) forms part of the broader assessment of the reference tariff and reference tariff policy, rather than the ICB alone. Nevertheless, the Commission notes that 'efficiency in the level of the reference tariff' is interrelated with the concept of 'efficient costs' in section 8.1(a) and also the notion of replicating the outcomes of a competitive market (section 8.1(b)). Moreover, if the ICB were set at a level above efficient costs and that which would be observed in a competitive market, and therefore incorporated monopoly rents, a service provider would have less of an incentive to reduce costs and develop the market.

The Commission's conclusions on the initial capital base

Section 8.11 of the Code provides that the value of the ICB should not normally fall outside the values of DAC and DORC. The Commission does not consider that the circumstances of the MSP warrant a value outside this range.

The Commission has decided not to approve EAPL's proposed value for the ICB of $779 million. In proposing this value EAPL relied on section 8.10(g) of the Code which requires the Commission to consider the reasonable expectations of persons under the previous regime that applied to the pipeline prior to the commencement of the Code. The Commission does not consider that EAPL has demonstrated that this value was brought about or underpinned by the previous regulatory regime. Accordingly, the Commission does not consider that EAPL's proposal satisfies section 8.10(g).

For the purposes of the MSP access arrangement the Commission has determined a value for the ICB of $559 million. To support this valuation, the Commission has given considerable weight to section 8.10(f) of the Code, which requires the Commission to have regard to the basis on which tariffs have been set (or appear to have been set) in the past, the economic depreciation of the pipeline and historical returns to the service provider.

The basis of the valuation is ORC, which the Commission has depreciated on the assumption of a 50 year asset life to 2000, consistent with the useful asset life previously assumed by EAPL. From 2000 onwards, the Commission has used an 80 year, the life which EAPL has submitted is the current useful life and which the Commission has accepted. Use of ORC is preferred to some historical measure of costs as ORC reflects the current costs of the assets and eliminates any redundant assets.

Having regard to all the relevant factors in section 8.10 of the Code, the Commission considers that a value for the ICB of $559 million best satisfies the objectives contained in section 8.1. For the purposes of establishing the value of the ICB, the Commission considers that three criteria of section 8.1 are particularly relevant. These are: section 8.1(a) (recovery of efficient costs); section 8.1(b) (replicating the outcomes of a competitive market); and section 8.1(d) (not distorting investment decisions). The Commission notes the relationship between criteria 8.1(a) and 8.1(b) and the Court of Appeal's comments that over time prices in a competitive market will replicate efficient costs.

The Commission does not consider that a DAC of $100 million would satisfy section 8.1(a) and 8.1(b), given the policy of the previous owner, the Australian Government, not to earn a commercial rate of return. In addition, the Commission does not consider that a value equal to DORC of $715 million and based on an 80 year life is appropriate, since a 50 year life has been assumed in the past. If the useful life of an asset changes at a particular point in time it is appropriate that the residual value of the asset would then be depreciated over the revised useful life. However, an extension to the useful life should not necessarily lead to an upward revision of the asset value. To do so would allow the asset owner to recover more than the efficient costs of the asset over the life of the asset.

Accordingly, the Commission considers that a value for the ICB of $559 million based on the useful asset life assumed in the past (50 years) coupled with future depreciation charges based on the current assumed life (80 years) best allows EAPL to recover the efficient costs over the expected life of the MSP and replicates the outcomes of a competitive market.

In addition, there are other matters which the Commission considers supports its conclusion that a value of $559 million best satisfies the section 8.1 criteria.

First, the Commission has had regard to the loss of market share to the EGP. Reference tariffs typically are determined by dividing costs by volumes. This suggests that, in the absence of the EGP, volumes transported through the MSP would be higher and, consequently, tariffs would be lower. The entry of a new firm should not signal a higher price for the incumbent's services. Such an outcome would not replicate the outcomes of a competitive market.

The approach adopted by the Commission to determine the value of the asset base replicates the performance of an incumbent firm that has recovered a substantial portion of its investment prior to the entry of a new firm. In this manner the incumbent could still be in a position to recover its investment over the life of the asset at current or lower prices notwithstanding a loss of market share. Adoption of the previous assumed asset life (50 years) to determine the asset base and the current assumed asset life (80 years) to determine future depreciation charges produces a kinked (accelerated) depreciation schedule. In other words, the capital base of the ICB has been written off at a faster rate prior to the entry of the EGP.

Second, and similarly, tariffs derived from an ICB value of $559 million are also broadly consistent with the tariffs that would be derived under the HNET. This test determines a hypothetical contestable price in a market that is not actually contestable. Under this test it is assumed that the optimal asset servicing the NSW and ACT markets is one pipeline displacing both the MSP and the EGP. Since both incumbents are displaced the anomaly of a new entrant putting upwards pressure on the incumbent's prices does not arise.

In determining reference tariffs, section 8.1(d) of the Code requires the Commission to consider the implications on investment, not only in the transportation of gas, but also on upstream and downstream industries. The Court of Appeal found that past investment decisions are relevant as well as future decisions. Distortions in investment can be minimised if tariffs are based on the efficient costs of delivering services. The Court of Appeal found that tariffs based on historical or forward-looking costs could satisfy this criterion.

The Court of Appeal also found that the price paid by a service provider in acquiring a pipeline prior to the Code was a relevant factor in this regard, as the price paid could be considered the service provider's investment in the asset. While the Commission does not consider that the price paid by EAPL in 1994 should form the basis of the ICB, the value of the ICB determined by the Commission will provide EAPL with the opportunity to recover the price it paid (after taking account of depreciation and capital expenditure to date).

The ICB approved by the Commission is shown in Table 2.2.7.1. In accordance with the methodology proposed by EAPL, the Commission has used ORC as the basis for allocating the value for the ICB across pipeline segments. The Commission considers this appropriate for the MSP as it avoids pricing distortions associated with assets of different vintages.

Table 2.2.7.1: MSP approved initial capital base by pipeline segment ($ million)

	ORC	ICB
Moomba to Wilton	919.9	470.8
Dalton to Canberra	19.9	10.2
Young to Lithgow	53.5	27.4
Junee to Griffith	31.9	16.4
Young to Wagga	40.7	20.9
Wagga to Culcairn	27.1	13.9
Total	**1092.9**	**559.3**

Amendment FDA 1

In order for EAPL's proposed access arrangement for the MSP to be approved, the value of the ICB must be set at $559.3 million (real 2002/03).

2.3 New facilities investment

2.3.1 Code requirements

Section 8.15 of the Code allows for the capital base to be increased in recognition of additional capital costs incurred in the construction, development or acquisition of new facilities for the purpose of providing services (new facilities investment). Prior to April 2003 the definition of 'new facilities' was limited to extensions and expansions of the covered pipeline. However, following the seventh amendment to the Code the definition has been expanded to also include any relevant capital asset constructed, developed or acquired by the service provider.[141]

[141] National Third Party Access Code for Natural Gas Pipeline Systems: Seventh Amending Agreement, 16 April 2003.

Section 8.16(a)(i) provides that the actual amount of the new facilities investment may be added to the capital base provided that the costs do not exceed those which would be incurred by a prudent service provider acting efficiently, in accordance with good industry practice, and to achieve the lowest sustainable cost of delivering services.

In addition, section 8.16(a)(ii) requires that one of the following conditions must also be satisfied:

- the anticipated incremental revenue (at prevailing tariffs) exceeds the cost of the new facility; or
- the new facility has system-wide benefits that justify higher reference tariffs for all users; or
- the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

In considering section 8.16(a)(i) the regulator must, pursuant to section 8.17, consider:

- whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and
- whether the lowest sustainable cost of delivering services over a reasonable time frame may require the installation of a new facility with capacity sufficient to meet forecast sales of services over that time frame.

Section 8.18 allows a service provider to undertake new facilities investment that does not meet the section 8.16(a) criteria. However, the capital base may be increased only by that amount that does satisfy these criteria (recoverable portion). The balance may be included in a ‘speculative investment fund’ and later added to the capital base should it then satisfy the section 8.16(a) criteria (section 8.19).

Section 8.20 allows reference tariffs to be based on forecast capital expenditure, provided the requirements in section 8.16 are reasonably likely to be met when the capital costs are forecast to be incurred. This does not, however, bind the regulator to add in the forecast costs to the capital base. Section 8.21 provides the regulator with the option of deciding at a later date whether the new facilities investment meets the requirements of section 8.16(a). Under section 8.22 the reference tariff policy should describe, or the regulator determine at the next review, how the new facilities investment is to be added to the capital base. This includes how the capital base at the commencement of the next access arrangement period will be adjusted for any discrepancies between forecast costs and actual costs.

Sections 8.23 and 8.24 allow for new facilities to be funded by a user (capital contribution) and such facilities to be added to the capital base, while sections 8.25 and 8.26 describe the circumstances under which a ‘surcharge’ may be levied on users of incremental capacity.

2.3.2 Original access arrangement

In its original access arrangement, EAPL’s proposed new facilities investment included a compressor on the Interconnect at Uranquinty and partial looping of the Canberra lateral. In addition EAPL proposed to incorporate the costs of the Interconnect (which was operational at that time) into the ICB.

Essentially, EAPL submitted that the new facilities investment was required to cater for a forecast increase in demand. A study undertaken by EAPL found that partial looping of the Canberra lateral was a more economically viable proposition than compression. Other capital expenditure included operating capital expenditure and in line (intelligent pig) inspections. Details of the capital expenditure forecast in May 1999 are shown in Table 2.3.2.1.

Table 2.3.2.1: Estimated capital expenditure (July 2000 $ million)

Year ending 30 June	2001	2002	2003	2004	2005	Total
Canberra looping	3.458					3.458
Uranquinty compressor			13.919			13.919
Operating capex	1.886	1.676	1.306	1.321	1.333	7.522
In line inspections				2.707		2.707
Total	**5.345**	**1.676**	**15.226**	**4.028**	**1.333**	**27.608**

Source: EAPL access arrangement information, 5 May 1999, p. 30

2.3.3 Commission's Draft Decision

In the *Draft Decision* the Commission concluded that EAPL's proposed new facilities investment would have been reasonably expected to meet the requirements of section 8.16(a) of the Code.[142] Hence the Commission proposed to include EAPL's forecast capital costs in the calculation of reference tariffs. The Commission noted, however, that it was not intended that the forecast costs would be rolled into the asset base at the review of the access arrangement. Rather an assessment of whether the actual capital expenditure incurred complied with section 8.16 would be made at that time.

2.3.4 Submissions in response to the Draft Decision

No submissions were received from interested parties in response to the Commission's *Draft Decision* on this issue.

2.3.5 Revised access arrangement

In May 2002, EAPL submitted revised forecast capital expenditure in association with it revised access arrangement. Both the Canberra looping ($3.5 million in 2007) and the Uranquinty compressor ($16.3 million in 2008) were included in the forecasts. However, both projects were forecast to be commissioned in later years to those

[142] This included the Interconnect. While the Commission has not changed its view on inclusion of the Interconnect, it considers that the appropriate Code provisions in this instance are sections 8.10 and 8.11. The Commission notes that section 8.16(a) of the Code provides for the capital base to be increased by the amount of new facilities investment incurred in the immediately preceding access arrangement period. In this case there is no immediately preceding access arrangement period. The test under 8.16(a) would normally be whether the new facilities investment is economic at prevailing tariffs. If not, a system wide benefits test applies. In the case of the Interconnect, EAPL is proposing to include the Interconnect in the ICB, which is one of the determinants of reference tariffs. Accordingly, the Commission considers that sections 8.10 and 8.11 of the Code, which deal with the establishment of the value of the ICB, are the more relevant Code provisions.

proposed in the original access arrangement due to a reduction in the forecast growth rate of demand.

An additional item included in the revised access arrangement was the construction of a compressor on the Northern lateral. This was forecast to cost $2.5 million and was expected to be constructed in 2004. In proposing this new facility EAPL submitted that:

> The Northern Lateral has a single reciprocating compressor (called the Young-Lithgow or YL Compressor), to boost delivery pressures at the Lateral's extremities in peak periods. There is no backup unit, in the event of compressor failure. While this unit has historically operated for short periods in winter only, recent modelling indicates that substantial growth in the area will result in peak system constraints requiring expansion as early as 2004.
>
> The Northern Lateral compressor will be increasingly used to assist the northbound flow of gas through the Interconnect in the shoulder and summer periods. This use of the unit will result in greater likelihood of unplanned interruption and maintenance.
>
> The capital cost of expanding the Northern Lateral capacity in 2004 is estimated at $2.5m, based on the cost of adding a duplicate reciprocating compressor unit to the existing station. However, pending further detailed analysis, a larger compressor, partial looping , or some combination of the above may be appropriate solutions. A detailed cost-benefit analysis of the most appropriate expansion option(s) is yet to be undertaken.[143]

In terms of the criteria contained in section 8.16 of the Code, EAPL stated:

> As growth in load is the main driver for this expansion, the anticipated incremental revenue generated by the additional capacity is expected to cover a significant proportion of the costs of the expansion (test (i)).
>
> Continuing load growth on both the Northern Lateral and increasing use of the Interconnect will require the installation of a duplicate compressor to allow for periods of planned and unplanned maintenance. The investment in capacity expansion is needed to provide system wide benefits of security of supply (test (ii)) and to maintain the integrity and Contracted Capacity of Services (test (iii)).[144]

Other forecast capital expenditure proposed by EAPL included in-line (intelligent pig) inspection (according to EAPL it is required as a condition of its pipeline licence to undertake in-line inspections as part of sound routine maintenance[145]), overhaul of compressors (this was included in the original access arrangement as operating expenditure instead of capital expenditure) and stay in business (SIB) (or operating), capital expenditure. EAPL submitted that estimated costs of these items were based on historical costs and current industry knowledge.

Following downward revisions to its volume forecasts in May 2003, EAPL revised its proposed forecast capital expenditure, as shown in Table 2.3.5.1.

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143 EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 3.

144 EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 4.

145 EAPL revised access arrangement information, 7 July 2003, p. 14.

Table 2.3.5.1: Estimated capital expenditure (July 2001 $ million)

Year ending 30 June	2003	2004	2005	2006	2007	2008
Northern lateral expansion				4.05		
In-line inspections		2.70				
Compressor overhaul			1.10			1.10
Stay in business	0.64	0.40	0.40	0.40	0.40	0.90
Total	**0.64**	**3.01**	**1.50**	**4.45**	**0.40**	**2.00**

Source: Access arrangement information, July 2003, p. 14.

As can be seen in the table above the downward revisions to volume forecasts have resulted in the Uranquinty compressor and Canberra looping projects being deferred beyond the initial access arrangement period. The commissioning of the compressor unit on the Northern lateral has also been delayed although it is expected to be constructed within the access arrangement period in 2006. The size of the compressor has, however, changed from a 400kw compressor to a 600kw compressor. Consequently, the forecast cost has increased from $2.5 million to $4 million. EAPL has advised the Commission that while the initial $2.5 million estimate was based on the cost of adding a duplicate reciprocating compressor unit to the existing station, a detailed cost-benefit analysis of the most appropriate option for expansion had not been undertaken at that stage. EAPL later submitted that a detailed analysis had established that the most efficient option was the installation of a 600kw compressor at an estimated cost of $4 million.[146]

Apart from these specific forecasts for new facilities investment EAPL has proposed that:

- the capital base at the next access arrangement be adjusted in accordance with the actual cost of the new facilities investment if the actual cost differs from the forecast costs (clause 8.4);
- it may undertake new facilities investment in the future that does not meet the requirements of the Code for inclusion in the capital base (clause 8.6); and
- an amount in respect of the balance, after the deducting a recoverable portion of new facilities investment, may be subsequently added to the capital base if at any time the type and volume of services provided using the increase in capacity attributable to the new facility change such that any part of the speculative investment fund would then satisfy the requirements of the Code for inclusion in the capital base (clause 14.3 of the extensions and expansions policy).

2.3.6 Submissions in response to the revised access arrangement

No submissions were received in response to EAPL's revised access arrangement concerning its forecast capital expenditure.

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[146] EAPL letter to the Commission, 10 June 2003, p. 6.

2.3.7 Commission's considerations

Section 8.16(a) of the Code is designed to discourage excessive capital expenditure (or gold plating) and to include the most prudent option where more than one option is feasible (for example compression or looping).

Northern lateral expansion

The Commission considers that an upgrade consisting of the addition of a second back-up compressor at Young is justifiable. Projected demand for the Northern lateral support the current need for compression at Young during the peak winter season. Given the dependency on compression the Commission considers it would be prudent for EAPL to improve the reliability of compression at Young by installing a back-up compressor. Furthermore, the Commission considers that the addition of a compressor is reasonably likely to satisfy section 8.16(a)(ii)(c) of the Code in that it is likely to be necessary to maintain the safety, integrity or contracted capacity of services.

Accordingly, pursuant to section 8.20 of the Code the Commission considers that the proposed compressor on the Northern lateral is reasonably likely to pass the requirements in section 8.16(a) of the Code when the new facilities investment is forecast to occur. As a result the proposed capital expenditure will be incorporated into the determination of reference tariffs for the initial access arrangement period.

Other forecast capital expenditure

The remainder of EAPL's forecast capital expenditure includes an in-line (intelligent pig) inspection, the overhaul of compressor units and minor items of SIB (or operational) capital expenditure.

The Commission understands that certain provisions of EAPL's pipeline licences require periodical in-line inspections to monitor the integrity of the various pipelines in the MSP.[147] The Commission has assessed the proposed expenditure and is satisfied that the planned overhaul of compressors and SIB capital expenditure are costs that are likely to be incurred by a prudent service provider to maintain the safety, integrity or contracted capacity of services (section 8.16(a)(ii)(c)). The Commission also notes that these items are of a recurring nature and that the forecast costs are based on historical costs.

The Commission considers that this forecast capital expenditure is reasonably likely to pass the requirements of section 8.16 of the Code. Hence the Commission has included these forecast costs in the calculation of reference tariffs for the initial access arrangement period.

Adding capital expenditure to the capital base

Approval by the Commission to allow reference tariffs to be based on forecast capital expenditure does not mean that the capital expenditure will be automatically included in the capital base. That is, the Code allows the Commission to decide at a later date (for example, when the investment is made or at the next review of the access

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[147] EAPL access arrangement information, 5 May 1999, p. 31.

arrangement) whether the capital expenditure passes the tests under section 8.16 of the Code.

The Code allows the service provider to specify the approach for inclusion of the capital expenditure in the capital base, including adjustments for any discrepancies between forecast costs and actual costs. As set out previously, EAPL has proposed that the capital base would be adjusted by actual costs if they differ from forecast costs (clause 8.4).[148]

A literal interpretation of this clause would suggest that all capital expenditure would be included at actual cost, irrespective of whether the section 8.16 criteria are satisfied. This issue also arose in the Commission's assessment of the access arrangement proposed by NT Gas Pty Ltd (of which APT has a 96 per cent interest) for the Amadeus Basin to Darwin Pipeline (ABDP). In response to concerns raised by the Commission, NT Gas stated that automatic roll-in of actual capital costs without reference to the section 8.16 requirements was not its intention. Accordingly, the Commission required an amendment to the effect that only that capital expenditure which satisfied the requirements of section 8.16 of the Code would be rolled into the capital base. NT Gas complied with the Commission's proposed amendment.

In the case of the MSP access arrangement, the Commission does not consider that it is EAPL's intention that all actual capital expenditure should be added to the capital base without some assessment of the efficiency of the capital expenditure as required by the Code. Accordingly, for clarity the Commission requires an amendment to the access arrangement to this effect.

Amendment FDA 2

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.4 to clarify that actual capital expenditure must satisfy the requirements of the Code before it is added to the capital base.

Speculative investment

EAPL has proposed that it may undertake new facilities investment in the future that does not meet the requirements of the Code for inclusion in the capital base (clause 8.6). EAPL's proposed clause paraphrases the first part of section 8.18 of the Code, which states:

> A Reference Tariff Policy may, at the discretion of the Service Provider, state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of section 8.16(a).

However, section 8.18 of the Code also states that if the service provider incurs such new facilities investment the capital base may only be increased by that part of the new facilities investment that does satisfy section 8.16(a).

148 The Commission notes that this would involve removing from the capital base the forecast capital expenditure in real terms (that is using the previously assumed inflation forecast) and then adding back into the capital base the actual capital expenditure in real terms.

The Commission is concerned that EAPL's proposal as currently worded could be construed as allowing EAPL to include in the capital base all new facilities investment, including speculative investment, irrespective of whether the new facilities investment satisfies the requirements of section 8.16(a).

A similar issue arose in relation to the access arrangement for the ABDP, which initially included a similar provision to that proposed by EAPL for the MSP. In that instance the Commission noted that NT Gas' proposed clause may mislead or cause confusion amongst users and prospective users. Accordingly, the Commission required an amendment to the ABDP access arrangement.

The Commission considers that a similar amendment to clause 8.6 of the access arrangement is appropriate. The Commission considers that such an amendment will clarify that only that part of the new facilities investment that satisfies the requirements of the Code may be added to the capital base.

Amendment FDA 3

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.6 by adding that only that portion of the new facilities investment which satisfies the requirements of the Code may be added to the capital base.

Included in EAPL's proposed extensions and expansions policy is a provision (clause 14.3) that would allow for part of the speculative investment fund to be added to the capital base if the type and volume of services change to such an extent that a portion of the speculative investment would then satisfy the requirements of the Code (under section 8.16). This proposed clause is similar to section 8.19 of the Code, however, section 8.19 specifies that a provision of this nature is to be included in the reference tariff policy, rather than the extensions and expansions policy.

Section 8.19 of the Code is related to section 8.18 which allows the reference tariff policy to state that the service provider may undertake new facilities investment that does not satisfy the requirements of section 8.16 of the Code (EAPL's proposed clause 8.6). Therefore the Commission has included its assessment of those matters in this section of this *Final Decision*, rather than Chapter 3 which considers the proposed extensions and expansions policy.

In the *Draft Decision*, the Commission proposed that clause 16.7 of EAPL's originally proposed access arrangement (equivalent to clause 14.3 of the revised access arrangement) be amended to require EAPL to obtain the Commission's approval to include any amount satisfying section 8.16 of the Code within the capital base (proposed amendment A3.14).

The Commission has again examined this proposed amendment and in particular the combined operation of sections 8.19 and 8.16(a). Section 8.19 of the Code does not explicitly require the service provider to obtain the regulator's approval before adding those parts of the speculative investment fund which satisfy the requirements of section 8.16(a) to the capital base. That said, the regulator does have an implied role by virtue of the requirement that the amount to be included in the capital base must satisfy section 8.16(a). That is, in accordance with section 8.17 of the Code, it is the role of the regulator to administer section 8.16(a)(i), which is a mandatory component of the criteria set out in section 8.16(a). Section 8.16(a)(ii) also provides the regulator with an implied discretion to determine if the conditions have been met.

Thus, if EAPL were to seek to include in the capital base any portion of the speculative investment fund it would have to satisfy the Commission that the amount did not exceed what would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of providing the service. It would also have to satisfy the Commission that one of the conditions stipulated in section 8.16(a)(ii) has been met.

Accordingly, the Commission has a role in administering section 8.19 of the Code by virtue of the requirement that the capital expenditure must satisfy section 8.16(a). In addition, the Commission notes that such an adjustment to the capital base may only occur at the commencement of a new access arrangement period (section 8.15). This requires EAPL to either wait until the scheduled revisions submission date or to submit revisions to the access arrangement ahead of this date. These revisions would then be assessed by the Commission in accordance with the public consultation process set out in the Code.[149]

Notwithstanding this, the Commission considers that an explicit provision requiring EAPL to obtain its approval before rolling in those parts of the speculative investment fund which satisfy section 8.16 of the Code is required. The Commission considers this to be necessary because clause 14.3 in its current form may create confusion among users and prospective users as to who (the Commission or EAPL) decides the timing and the portion of the speculative investment fund to be added to the capital base. The Commission does not view this requirement as being either unnecessary, unreasonable or contrary to EAPL's legitimate business interests. Furthermore, such an amendment is not inconsistent with the Code. Accordingly, the Commission requires the following amendment.

Amendment FDA 4

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 14.3 to state that an amount in respect of the balance after deducting the recoverable portion of new facilities investment may subsequently be added to the capital base, with the approval of the Commission, if at any time the type and volume of services provided using the increase in capacity attributable to the new facility changes such that any part of the speculative investment fund would then satisfy the requirements of section 8.16(a).

In addition, for clarity and consistency with the Code, the Commission requires that clause 14.3 of EAPL's proposed access arrangement be moved from the extensions and expansions policy to the reference tariff policy.

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[149] See, for example, the Commission's decisions in relation to GasNet Australia's Interconnect and Southwest Pipeline

Amendment FDA 5

In order for EAPL's access arrangement for the MSP to be approved the provision contained in clause 14.3 of EAPL's proposed access arrangement (as amended according to this *Final Decision*) must be deleted from the extensions and expansions policy and inserted into the reference tariff policy.

2.4 Capital redundancy

2.4.1 Code requirements

Section 8.27 of the Code allows a reference tariff policy to include (and the regulator may require it to include) a mechanism that will remove redundant capital from the capital base. Such an adjustment would occur at the commencement of the next access arrangement period in order to:

- ensure that assets which cease to contribute to the delivery of services are not reflected in the capital base; and
- share costs associated with a decline in sales volume between the service provider and users.

Before approving such a mechanism, the regulator must consider the potential uncertainty and its effect on the service provider, users and prospective users.

Where redundant assets subsequently contribute to or enhance the provision of services, the Code (section 8.28) allows the assets to be returned to the capital base (including an allowance for a rate of return on the value of the redundant capital compounded from the time the redundant capital was removed from the asset base) as if they were a new facilities investment.

While the Code permits a reference tariff policy to include a mechanism to subtract redundant capital from the capital base, it also allows for other mechanisms that have the same effect on reference tariffs while not reducing the capital base (section 8.29 of the Code).

2.4.2 Original access arrangement

In its original access arrangement EAPL proposed that the capital base at the commencement of the subsequent access arrangement (clause 8.2(2)) be adjusted for redundant assets arising from preceding access arrangement period. However, no specific mechanism was contained in the proposed access arrangement to determine the extent of the redundant assets, if any.

2.4.3 Commission's Draft Decision

The *Draft Decision* proposed an amendment that would allow the Commission, at the commencement of the subsequent access arrangement period, to review, and if necessary, adjust the capital base for wholly or partially redundant assets (proposed amendment A2.2).

2.4.4 Submissions in response to the Draft Decision

In response to the Commission's proposed amendment EAPL noted that it did not object. No submissions were received from other interested parties.

2.4.5 Revised access arrangement

EAPL's revised access arrangement (clause 8.3) provides for the capital base at the commencement of the next access arrangement period to be adjusted for redundant capital (as well capital expenditure, depreciation and inflation). This provision as it relates to redundant capital, is consistent with section 8.9 of the Code.

EAPL has not, however, incorporated into its revised access arrangement the amendment proposed in the *Draft Decision* (and to which EAPL previously raised no objection), nor has EAPL proposed any other mechanism under section 8.27 of the Code for the treatment of redundant capital.

2.4.6 Commission's considerations

The Commission considers that a mechanism for redundancy is desirable to reduce uncertainty and ensure that users do not pay for assets that have ceased, or have substantially ceased, to contribute to the delivery of services. Accordingly, the Commission requires EAPL to amend its reference tariff policy to incorporate the amendment proposed by the Commission in the *Draft Decision*.

Amendment FDA 6

> In order for EAPL's access arrangement for the MSP to be approved, the reference tariff policy must be amended to allow the Commission, at the commencement of the subsequent access arrangement period, to review and, if necessary, adjust the capital base for wholly or partially redundant assets.

2.5 Depreciation

2.5.1 Code requirements

Under a cost of service approach, depreciation of the capital base represents one element of the costs used in establishing reference tariffs. Sections 8.32 and 8.33 of the Code require that each asset or group of assets must be assigned a depreciation schedule that is designed so that:

- the impact on reference tariffs is consistent with the efficient growth of the market for the related services (and which may involve a substantial portion of depreciation taking place in future periods, particularly where reference tariffs have been set on the assumption of significant market growth);
- depreciation occurs over the life of the assets with progressive adjustments where appropriate to reflect changes in economic lives; and
- the asset is depreciated only once and that total accumulated depreciation does not exceed the valuation of the asset when initially incorporated in the capital base.

Under the IRR or NPV methodology, section 8.34 requires that the notional depreciation over the access arrangement period for each asset or group of assets that form part of the capital base be the difference between the value of the asset in the capital base at the commencement of the access arrangement period and the value of that asset that is reflected in the residual value. Section 8.34 also provides that:

- the residual value of the covered pipeline should reflect notional depreciation that meets the principles of section 8.33; and
- the reference tariff should change over the access arrangement period in a manner that is consistent with the efficient growth of the market for the services (and which may involve a substantial portion of the depreciation taking place towards the end of the access arrangement period, particularly where the calculation of the reference tariff has assumed significant market growth and the pipeline has been sized accordingly).

Finally, section 8.35 of the Code provides that in implementing the principles set out in sections 8.33 and 8.34, regard must be had to the reasonable cash flow needs for non capital costs, financing cost requirements and similar needs of the service provider.

2.5.2 Original access arrangement

In accordance with the cost of service originally proposed, EAPL submitted depreciation schedules for each class of asset. For its pipeline assets, EAPL originally proposed a '5/8:3/8' kinked depreciation schedule. Under this methodology the major proportion of the asset (62.5 per cent) would be depreciated over the first half of the remaining economic life of the asset, while a lesser proportion (37.5 per cent) would be depreciated over the second half. According to EAPL recovery of a significant portion of the value of its pipeline assets earlier was justified because it faced a significant risk of stranding as a result of competition from the EGP.

For its other assets, compressors, metering, plant, machinery and equipment, and mobile equipment, EAPL proposed real straight line depreciation over the remaining economic lives of the assets. Total depreciation charges proposed by EAPL amounted to approximately $24 million to $25 million in real terms over the access arrangement period.

Subsequent to its original proposal, EAPL reconsidered its position and submitted that in its opinion a kinked depreciation schedule should not apply to the MSP and that straight line depreciation was more appropriate.[150] However, EAPL did not formally submit revisions to its proposed reference tariffs or reference tariff policy to incorporate straight line depreciation. Accordingly, the *Draft Decision* discussed both the merits of a kinked depreciation schedule (as originally submitted by EAPL) and a straight line depreciation schedule.

[150] EAPL letter to the Commission, 11 August 2000, p. 3.

2.5.3 Commission's Draft Decision

The Commission concluded that EAPL's proposed kinked depreciation schedule was inappropriate for the MSP as it delivered excessively high depreciation charges in early years and low depreciation charges in later years. The Commission considered that a kinked depreciation schedule was contrary to section 8.33 of the Code and inconsistent with the forecast market growth for the MSP. Consequently, the Commission proposed a real straight line depreciation schedule for the MSP (proposed amendment A2.6). Total depreciation charges proposed by the Commission amounted to approximately $12 million to $13 million per annum over the initial access arrangement period.

2.5.4 Submissions in response to the Draft Decision

Responding to the *Draft Decision* EAPL reiterated that it had no objection to the use of straight line depreciation.[151]

In contrast to this position, DEI supported the kinked depreciation schedule. DEI noted that it shared EAPL's concern regarding the potential stranding of assets as a result of competition from the EGP and stated that this risk should be taken into account in the depreciation schedule:

> … given the clear potential for asset stranding, if the MSP is prevented from recovering the initial capital through depreciation charges at a time when demand is strong (noting that the MSP is virtually at capacity now) then EAPL may ultimately under recover its initial investment.[152]

2.5.5 Revised access arrangement

In its revised access arrangement EAPL has proposed the NPV approach to the determination of total revenue. In accordance with this approach total depreciation is the difference between the value of the capital base at the start of the access arrangement period and the residual value at the end of the period. For each year of the access arrangement period depreciation is the amount remaining after deducting non capital costs, the return on assets and net taxes from revenue (Economic depreciation = revenue – (non capital costs + net taxes + return on assets)).

Total depreciation charges proposed by EAPL in May 2002 for the initial access arrangement period are shown in Table 2.5.5.1

Table 2.5.5.1: EAPL proposed depreciation as at May 2002 (July 2001 $million)

Year ending 30 June	2003	2004	2005	2006	2007	2008
Depreciation	2.04	(3.70)	(0.30)	7.34	15.00	16.48

Source: EAPL, *Information requested in ACCC letter dated 27/5/02*, submitted June 2002, p. 5.

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[151] EAPL response to the Draft Decision, 14 March 2001, p. 22.

[152] DEI submission, 9 February 2001, p. 9.

As indicated in Table 2.5.5.1, EAPL proposed a back-end loaded depreciation schedule with depreciation charges increasing over the remaining life of the assets as forecast volumes and revenue are forecast to increase. According to EAPL:

> The use of the NPV methodology allows for "back-ending" of depreciation, which provides greater opportunities to grow the market, particularly in regional centres.
>
> For the MSP, this means that during the early Access Arrangement Periods estimated returns will not be sufficient to cover the total costs (including profit and straight-line depreciation) of providing the Reference Services. While this applies to both the Mainline and the Regional Laterals, the level of under recovery for the Regional Laterals is very significant in early years. Accordingly, there is a need for a mechanism to provide for the under recovery of revenue in the early years of the MSP's life to be recouped in the later years of operation.
>
> The concept of back-ended depreciation – which often arises where the NPV methodology is applied – provides such a mechanism and, in respect of the MSP, is necessary to achieve the Code objective which requires that the Reference Tariffs be designed with a view to providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service.[153]

EAPL added that back-end loaded depreciation is consistent with section 8.33(a) of the Code which states that the depreciation schedule should be consistent with the efficient growth of the market.

In July 2003, EAPL submitted further revisions to its depreciation schedule as a consequence of revisions to forecast volumes. The revised depreciation charges are shown in Table 2.5.5.2

Table 2.5.5.2: EAPL proposed depreciation as at July 2003 (July 2001[(a)] $ million)

Year ending 30 June	2003	2004	2005	2006	2007	2008
Mainline	1.94	4.50	0.97	0.93	(1.15)	(5.07)
Laterals	(2.10)	(2.93)	(2.89)	(2.81)	(3.02)	(2.92)
Total	**(0.16)**	**1.57**	**(1.92)**	**(1.88)**	**(4.17)**	**(7.99)**

Source: Access arrangement information, July 2003, p. 2
Notes: (a) Although EAPL's submission states that the base year is 2000 models submitted to the Commission confirm that the base year is in fact 2001.

EAPL's proposed depreciation charges (as at July 2003) decrease over the initial access arrangement period in accordance with the projected decrease in throughput. According to EAPL the negative depreciation values represent an under recovery of costs, which would be recovered in subsequent access arrangement periods as volumes increase.

In relation to the anticipated under recovery of costs, EAPL stated:

> This section of the Code [section 8.33(a)] recognises that such a mechanism [back-end loaded depreciation] is necessary to justify commitment to major infrastructure projects, and that this objective outweighs any argument that the ability to roll forward estimated under recovery lessens incentives for efficiency. In addition, the Code recognises that inherent in investment in pipelines is a significant market risk associated with demand forecasts. What is unusual in

153 EAPL revised access arrangement information, 7 July 2003, p. 13.

> the case of the MSP is that a significant element of its market risk arises because of an unregulated competing pipeline - that is the EGP.[154]

In addition, EAPL stated that this approach to depreciation was consistent with the approach approved by the Commission for the Central West Pipeline (CWP).

2.5.6 Submissions in response to the revised access arrangement

At the time EAPL submitted its revised access arrangement in May 2002, TXU considered that EAPL had not provided sufficient details of its approach to depreciation to allow it to form a view as to its reasonableness or otherwise.[155]

2.5.7 Commission's considerations

The merits of a back-end loaded depreciation schedule in the case where volumes are forecast to rise over time were discussed in the *Draft Decision*. The back-end loaded approach would provide a more stable tariff path than other depreciation methodologies, such as straight line depreciation, in cases of forecast market growth. In contrast, tariffs would have a tendency to fall under a scenario of straight line depreciation coupled with market growth. Under these circumstances, a back-end loaded depreciation schedule would be more consistent with economic efficiency.

The *Draft Decision* did, however, note that there were some concerns with the back-end loaded approach to depreciation. Specifically, the Commission noted that if the forecast market growth did not eventuate then users may suffer price shocks to cover increased depreciation charges in the future. Moreover, in reference to the MSP, the Commission noted that under a back-end loaded depreciation profile the asset base over the initial access arrangement period would depreciate relatively little in value while at the same time EAPL received guaranteed minimum payments from AGL under the GTD.

Notwithstanding this, the Commission notes that the back-end loaded depreciation schedule under EAPL's NPV approach to determining revenue is consistent with section 8.34 and, as EAPL noted, section 8.33 of the Code. In particular, EAPL's proposal is consistent with the Code provisions (sections 8.33(a) and 8.34(d)) which state that the notional depreciation should accommodate reference tariffs that change in accordance with the efficient growth of the market and involves a substantial portion of the depreciation occurring in future periods. As noted above, the Commission considers that a back-end loaded approach to depreciation is consistent with economic efficiency under these circumstances.

As shown in Table 2.5.5.2 EAPL's proposed depreciation schedule includes negative depreciation (that is an under recovery of costs) over the initial access arrangement. These unrecovered costs would be recouped in later access arrangement periods as volumes and revenue grew. EAPL stated that this mechanism is necessary to justify

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[154] EAPL revised access arrangement information, 7 July 2003, p. 13.

[155] TXU submission covering letter, 29 July 2002, p. 2.

commitment to major infrastructure projects. EAPL also likened the approach to that incorporated in the CWP access arrangement.[156]

While this approach was adopted in the CWP Final Decision the two pipelines can be distinguished. At the time of the access arrangement assessment process the CWP was a new pipeline (although not a greenfields pipeline in the correct sense of the term). The CWP had no foundation customers and had forecast a low level of demand for the initial access arrangement period (and some years beyond). Accordingly, the service provider and the Commission agreed that cost recovery tariffs would be too high for the market to bear and would have a significant impact on market development. Accordingly, tariffs were set with the objective of growing the market with initial losses being recouped in later years as demand increased.[157]

While the incurrence of losses may be an appropriate approach to tariff setting for the initial tariffs of a new pipeline with low demand, the Commission does not necessarily consider that an under recovery of costs is appropriate for an established pipeline such as the MSP which supplies sufficient volumes to relatively mature markets. Moreover, it appears to the Commission that the under recovery of costs is largely a function of the high value for the ICB proposed by EAPL ($779 million).

Thus, while the Commission accepts EAPL's economic depreciation methodology, the depreciation charges approved by the Commission for each year of the access arrangement period will differ to those proposed by EAPL to reflect the various amendments required in this *Final Decision* (such as the value of the ICB). The annual depreciation charges approved by the Commission reflect the movement in forecast volumes over time, with depreciation charges falling as forecast volumes decrease over the initial access arrangement period. The current projections are for volumes to increase in the medium to long term which would result in increasing economic depreciation in future access arrangement periods. Those forecasts will be reconsidered at the first review of the access arrangement.

Table 2.5.7.1 shows the depreciation charges (in real terms) that are approved by the Commission for the initial access arrangement period.

Table 2.5.7.1: Commission approved depreciation charges (July 2003 $ million)

Year ending 30 June	**2004**	**2005**	**2006**	**2007**	**2008**	**Total**
Mainline	16.01	13.77	12.24	9.05	7.95	**59.01**
Regional	0.22	0.31	0.42	0.28	0.33	**1.56**
Total Depreciation	**16.22[(a)]**	**14.08**	**12.66**	**9.33**	**8.28**	**60.58**

Notes: (a) Totals may not add up due to rounding.

156 EAPL revised access arrangement information, 7 July 2003, p. 13.

157 ACCC, *Final Decision: Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline,* 30 June 2000, pp 70-71.

Amendment FDA 7

In order for EAPL's access arrangement for the MSP to be approved, EAPL must adopt the depreciation schedule contained in Table 2.5.7.1 of this *Final Decision*.

2.6 Rate of return

2.6.1 Code requirements

Section 8.30 of the Code states that the rate of return used in deriving a reference tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (as reflected in the terms and conditions on which the reference service is offered and any other risk associated with delivering the reference service).

Section 8.31 of the Code provides further guidance on the application of section 8.30. It states that the rate of return may be set on the basis of a weighted average of the return applicable to each source of funds (for example, equity and debt). These returns may be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model (CAPM). In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted if the regulator is satisfied that the objectives set out in section 8.1 of the Code are met.

By its very nature, the rate of return expected to prevail over the access arrangement period is a forecast. Section 8.2(e) of the Code requires that where forecasts are used to set reference tariffs the regulator must be satisfied that the forecasts represent best estimates arrived at on a reasonable basis. Consequently, section 8.2(e) may be regarded as providing the regulator with further guidance relevant to determining whether the parameters underlying the proposed rate of return will result in a rate of return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service.

In instances where a range of values have the quality required by section 8.2(e) the regulator may then have recourse to the reference tariff principles set out in section 8.1 of the Code and the factors set out in section 2.24 to determine the most appropriate value applicable to the access arrangement under assessment.

2.6.2 Original access arrangement

Drawing upon a number of assumptions and parameters, EAPL's original access arrangement (submitted in May 1999) proposed a pre-tax real rate of return of 8.4 per cent. Briefly, these assumptions and parameters included: [158]

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[158] EAPL access arrangement information, 5 May 1999, pp. 32-35.

- Effective tax rate: 36 per cent. This rate was in line with the prevailing company tax rate at the time;
- Value of imputation credits: 0.4 – 0.5. EAPL noted that this range was consistent with decisions made by the ORG (now the ESC), the Commission and IPART;
- Gearing ratio: 60:40. EAPL submitted that this value was in line with the industry standard and previous decisions by the ORG, the Commission and IPART;
- Real risk free rate: 3.3 per cent (nominal risk free rate of 5.85 per cent). EAPL considered the current yield on CPI indexed bonds (which at the time was between 3.5 - 3.6 per cent) to be the best indicator of the real risk free interest rate. EAPL also noted that the nominal yield on 10 year bonds was around 5.5 to 5.6 per cent which, after deducting an inflation rate of 2.0 to 3.0 per cent, resulted in an implied real risk free rate of around 3.0 per cent. To arrive at its proposed nominal risk free rate of 5.85 per cent, EAPL adjusted the real risk free rate by an inflation rate of 2.5 per cent using the Fisher Equation.[159]
- Debt margin: 130 – 140 basis points. Underlying this estimation was EAPL's assumption of a benchmark financing structure and an investment grade credit rating;
- Market risk premium: 6 per cent. EAPL submitted that this value was consistent with previous regulatory decisions by the ORG and the Commission;
- Equity beta: 1.2 – 1.45 derived using an asset beta of 0.55 – 0.65 and a debt beta of 0.12. In proposing these values EAPL submitted that it was exposed to a greater level of systematic risk than that faced by Victorian transmission and distribution businesses. Accordingly, EAPL argued that a higher beta range than those used by the Commission and the ORG was appropriate for the MSP. EAPL attributed the higher level of exposure to risk to:
- The composition of the final market. EAPL submitted that large users accounted for a greater proportion of the NSW gas market than the Victorian market and as a result would render the revenue stream attributable to those users more volatile; and
- The maturity and final prices of the NSW market. EAPL submitted that: the NSW market was not as deep as the Victorian market; city gas prices were significantly higher than in other states; and NSW had a greater exposure to competing energy options. According to EAPL, the culmination of these factors would render final gas demand more sensitive to small movements in market-wide factors.

In addition to these factors, EAPL noted that although Moomba was expected to be a supply hub in the longer term, it was exposed to the uncertainty surrounding the timing and pricing of gas supply sources beyond the Cooper Basin.[160]

Combined these parameters resulted in nominal cost of debt within the range 7.3 – 7.4 per cent and a nominal cost of equity within the range 13.1 – 14.6 per cent.

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159 The Fisher Equation can be described as $1+ r_{f1}=(1+ r_{rf})*(1+f)$ where f is the expected inflation rate; r_f is the nominal risk free rate and r_{rf} is the real risk free rate.

160 EAPL access arrangement information, 5 May 1999, pp. 33-34.

The post-tax nominal weighted average cost of capital (WACC) was then calculated to be within the range of 6.8 – 7.5 per cent. To obtain a pre-tax real rate of return, EAPL grossed up the post-tax nominal rate by the assumed taxation rate and then adjusted for inflation through the use of the Fisher equation. These adjustments resulted in a pre-tax real WACC range of 7.9 – 9.0 per cent. Within this range, EAPL proposed a pre-tax real WACC of 8.4 per cent based on 'commercial judgment and relevant benchmark rates of return'. [161]

2.6.3 Commission's Draft Decision

The Commission's *Draft Decision* proposed that EAPL amend its WACC estimates and associated parameters to more accurately reflect market conditions. In particular, the post-tax nominal return on equity, the pre-tax real WACC and the expected inflation rate which the Commission considered should be set at 13 per cent, 7 per cent and 2.9 per cent respectively (proposed amendment A2.8).

Pre-tax versus post-tax measures of the WACC

As discussed in other regulatory decisions, the *Draft Decision* noted that the formulae used to transform the post-tax return on equity to a post-tax nominal WACC and on to a pre-tax real WACC, were incorrect when applied in a regulatory framework, as they did not deliver the intended return to equity holders. The Commission noted that timing differences between prima facie tax expenses and actual payment of taxes as a result of accelerated depreciation and other tax concessions were likely to have the effect of improved effective returns to shareholders. In such circumstances, the inclusion of the company tax rate in the formula is likely to result in an overstatement of the effective tax rate and in turn an overstatement of the required return on equity.

In light of these limitations, the Commission reiterated that its preferred approach was to model cash flows in a post-tax framework. The Commission noted that this approach overcomes the problems associated with a pre-tax framework, provides a return that is commensurate with market requirements and avoids potentially incorrect compensation for future tax liabilities.

The Commission also stated that within the post-tax framework, the regulatory revenue stream provides compensation for actual tax liabilities as they occur. As a result, the profile of that revenue stream will initially be low when the entity takes advantage of available tax concessions and will become higher as those concessions expire and tax liabilities become payable. The Commission noted that such a tariff path would be inequitable with future customers paying a level of the service provider's tax liabilities. To remove these undesirable features the Commission 'normalised' the forecast revenues over the life cycle of the assets. [162]

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[161] EAPL access arrangement information, 5 May 1999, p. 35.

[162] Normalisation is a procedure whereby the deprecation is contoured to be relatively higher when no tax is payable but lower when taxes become payable. This is done in such a way that revenues and tariffs are levelised with respect to tax liabilities.

The Commission concluded that regardless of whether a pre-tax real or post-tax nominal WACC is used, the rate of return critical to the regulatory framework is the post-tax nominal return on equity, derived through the CAPM.

Effective tax rate

In relation to the effective tax rate, the *Draft Decision* commented that as a result of timing differences in tax payments (caused by the different rates of depreciation for tax and accounting purposes) the effective tax rate over the life of the asset was likely to be less than the company tax rate. Specifically, the Commission noted that the deferral of tax liabilities results in an improved cash flow, a more rapid payback of capital and an internal rate of return greater than might otherwise be the case. Thus the inclusion of the company tax rate in the formula is likely to result in an overstatement of the effective tax rate and in turn an overstatement of the required return on equity.

The Commission noted that this issue was particularly relevant to EAPL as it had been able to apply accelerated depreciation to its purchase price of the MSP and would continue to defer its income tax liabilities over the initial access arrangement period.[163] The Commission observed that as a result of this deferral, initial tariffs would be relatively low but would rise in subsequent periods when EAPL no longer had the ability to take advantage of the benefits associated with tax depreciation and the tax liabilities were added to the cost structure. To avoid timing distortions the Commission utilised cash flow analysis and a post-tax normalisation approach which assumed a company rate of taxation of 34 per cent for the financial year 2000/01 and 30 per cent thereafter.

The Commission's cash flow modelling indicated an effective tax rate (T_e) of 13.6 per cent the Commission pointed out that cash flows are generated independently of the effective tax rate.

Value of imputation credits

The Commission referred to the uncertainty surrounding the appropriate value of imputation credits and noted that some factors appeared to suggest that the appropriate value for the utilisation of imputation credits was one. Nevertheless, the Commission concluded that a value of 0.5 could be considered the minimum and noted that it would retain this value for present purposes.

Capital structure

The Commission's decision regarding the appropriate gearing level acknowledged the Modigliani-Miller theorem which suggests that the cost of capital, in the absence of taxes, is invariant over a range of gearing ratios. The Commission stated that it considered that this holds approximately true when taxes are considered and concluded

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163 EAPL argued that the company tax rate was applicable because it would begin to incur tax liabilities during the initial access arrangement period. The Commission noted that this may be the case on the basis of EAPL's actual revenue. However, that revenue is based on the minimum payments guaranteed by the GTD and will be different to the regulated revenue stream determined in the Draft Decision and unaffected by any regulatory decisions.

that the level of gearing is not a critical factor in the formulation of the WACC.[164] Accordingly, the Commission accepted EAPL's 60:40 debt to equity ratio.

The cost of debt

While acknowledging that 10 year bond rates can be used as a proxy for the risk free rate, the Commission noted that generally it considered that the term associated with the risk free rate should coincide with the duration of the access arrangement period. The main difference between the 5 and 10 year bond rate is accounted for by a premium to compensate for interest rate risk in years 6 to 10. However, over a five year access arrangement period the service provider will not face such risks. Accordingly, the Commission concluded that the relevant risk free rate was one that matched the access arrangement period, which in this instance was five years.

In regard to the appropriate measure of expected inflation, the Commission noted that such an indicator could be derived by calculating the difference between nominal bond rates and indexed bond rates for the same term. This would reflect the rate of inflation anticipated by financial markets for the period. As the relevant period set in the *Draft Decision* was five years, five year bond rates were used to provide an expected inflation rate for the initial access arrangement period.

In determining the appropriate debt margin, the Commission referred to the CWP Final Decision and the MAPS Draft Decision and then concluded that a debt margin of 120 basis points was also appropriate for the MSP. Adding this margin to the risk free rate of 6.0 per cent yielded a nominal cost of debt of 7.2 per cent. With an inflation rate of 2.9 per cent the corresponding real cost of debt was 4.2 per cent.

The return on equity

In the *Draft Decision* the Commission noted that there was little evidence to suggest that the market risk premium was above 6 per cent and added that the lower end of the reasonable range remained a source of contention. Recognising that the downward trend had not been fully accepted by market participants and commentators, the Commission accepted that 6 per cent was appropriate in the current environment. Notwithstanding this, the Commission advised that it would reconsider the appropriate value over time as decisions were made and further empirical work became available.

On the issue of the appropriate equity beta, the Commission concluded that there was no evidence to support EAPL's contentions that its asset and equity beta should be higher than those applied to the Victorian transmission and distribution systems. Specifically, the Commission concluded that:

- EAPL's greater reliance on large industrial users may result in volatility, however, due to the increased penetration in the tariff market this volatility should diminish;
- Competition from the EGP was a specific risk to the MSP and not a systematic risk and is already reflected in the demand forecasts rather than the CAPM; and

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[164] For example, if the level of gearing is increased, the WACC will not decrease despite the increase in the level of debt, the cost of which is less than the cost of equity, because of an offsetting increase in the riskiness of equity returns due to gearing.

- Variations in gas demand associated with changing economic conditions are more likely to have a greater impact on the pipeline owner's revenue under a market carriage system (as in Victoria) than a contract carriage system such as the MSP. In reaching this conclusion, the Commission noted that tariffs are based on throughput under the market carriage system and have a direct relationship to volumes transported. This compares to the tariff structure on the MSP where revenue is primarily generated through tariffs based on reservation of capacity.

In the absence of market based estimates of betas for Australian regulated companies the Commission considered a more relevant guide to determine a suitable asset beta for the MSP was the asset beta determined for the MAPS. Underpinning this consideration was the observation that like the MSP, the MAPS was a mature pipeline.

With regard to the debt beta, the Commission referred to the 0.6 value adopted for the MAPS. Utilising the Monkhouse formula,[165] a 0.6 debt beta and a 0.50 asset beta then yielded an equity beta of 1.16 for the MSP.

2.6.4 Submissions in response to the Draft Decision

The Public Interest Advocacy Centre (PIAC) submitted that the proposed 13 per cent nominal return on equity was considerably higher than other returns on equity (including the 11.3 per cent 10 year average return on the stock market) and in effect represented a guaranteed return.[166] The PIAC concluded that in its view such a return would not result in investors withholding investment in gas pipelines, as predicted by the Australian gas industry.

The EUAA expressed its disappointment in the Commission's proposal for a pre-tax real rate of return of 7 per cent and argued that in light of the level of risk assumed by EAPL, a more appropriate pre-tax real rate of return was less than 5 per cent.[167] The EUAA also had some concerns in relation to the determination of the effective tax rate. The EUAA stated that the actual rate of tax paid by EAPL since its purchase of the assets in 1994 and forecast tax rates for the next five years would provide a solid basis for determining the appropriate allowance for the taxation parameter.

EAPL's response to the Draft Decision

EAPL asserted that the Commission had made a number of errors in deriving the cost of equity and the WACC and as a result the Commission's proposed rate of return was not consistent with the Code.[168] EAPL also stated that setting the rate of return at such a low level had the potential to affect detrimentally the interests of users in the longer term and jeopardise plans for further pipeline construction and interconnection. It concluded that:

> Any assessment of the cost of capital, including the WACC approach, provides a framework for identifying the cost of capital, and produces a range of values rather than a

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165 $\beta_e = \beta_a + (\beta_a - \beta_d).(1-(r_d/(1+r_d)).(1-\gamma)T_e)D/E$

166 Public Interest Advocacy Centre submission to the Commission, 12 February 2001, p. 1.

167 Energy Users Association of Australia submission to the Commission, 21 February 2001, p. 2.

168 EAPL response to the Draft Decision, 14 March 2001, p. 17.

> precise answer. If returns are set below the market cost of capital, the investment necessary for development and innovation will be discouraged. Accordingly, once the possible range for the cost of capital is identified, the Commission should establish a return at the higher, rather than the lower, end of the range to ensure that its decision does not deter necessary investment.[169]

EAPL's specific contentions regarding the errors made by the Commission in deriving the return on equity and WACC are set out below.

Pre-tax versus post-tax measures of the WACC

EAPL questioned the Commission's decision to model tax costs through cash flows rather than directly in the WACC.[170] EAPL stated this approach was not favoured because:

- it suggests that decisions as to corporate structuring and tax planning are matters for control by the regulator, rather than management of the company;
- the consequence of this approach is that the allowed rate of return relies on assumptions made by the Commission as to the consequences for the regulated business of the application of complex and often contentious tax legislation; and
- it introduces additional complexities, thereby increasing the potential for error.

Notwithstanding this, EAPL stated that it would not object to the adoption of this approach provided that the tax modelling was correct.

Value of imputation credits

With regard to imputation credits, EAPL asserted that no move should be made to increase the value without further study and consultation.[171]

Debt margin

EAPL submitted that the 120 basis points debt margin proposed by the Commission was not based on capital market information and as such did not reflect the market conditions for funds as required by the Code. EAPL concluded that a debt margin determined on the basis of capital market information should be approximately 135 basis points.[172]

Market risk premium

On the issue of the appropriate market risk premium, EAPL noted that there were studies which indicated that the long term arithmetic mean of the historically observed market risk premium exceeded 6 per cent.[173] Accordingly, EAPL submitted that a market risk premium of less than 6 per cent could not be justified.

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169 EAPL response to the Draft Decision, 14 March 2001, p. 17.

170 EAPL response to the Draft Decision, 14 March 2001, p. 18.

171 EAPL response to the Draft Decision, 14 March 2001, p. 19.

172 EAPL response to the Draft Decision, 14 March 2001, p. 18.

173 EAPL response to the Draft Decision, 14 March 2001, p. 18.

Asset beta

In response to the Commission's proposal to adopt a 0.5 asset beta, EAPL argued that a more appropriate range for the asset beta was 0.55 – 0.6. In support of this, EAPL noted that:

- the MSP is not fully contracted;
- the market served by the MSP is smaller and not as deep as the market served by the Victorian gas transmission assets; and
- the MSP is not the only pipeline transporting natural gas to the market served by it.

Conclusion

In light of the foregoing, EAPL submitted that a more appropriate return on equity and pre-tax real WACC were 13.67 per cent and 7.17 per cent respectively.

2.6.5 Revised access arrangement

As in the original proposed access arrangement, EAPL's revised access arrangement proposes the use of the WACC using the CAPM to determine the appropriate rate of return for the MSP.[174] Specifically, EAPL has proposed a pre-tax real WACC of 7.9 per cent. According to EAPL, the pre-tax measure is preferable primarily because:

- it is simple to apply when modelling and only requires the calculation of pre-tax cash flows or EBITs;
- it avoids the requirement for complex notional tax calculations; and
- its use reflects the imprecision of estimating the WACC, recognising that many of the variables used to calculate WACC have a wide range of uncertainty.

The specific parameters, equations and other assumptions underlying the 7.9 per cent pre-tax real WACC are set out in Table 2.6.5.1 below. According to EAPL, these values have been selected to:

> …reflect an appropriate point in the range which will avoid inappropriate and undesirable under estimation of the WACC.[175]

The methodology and assumptions underlying each of these parameters are set out below under the relevant headings.

Pre-tax versus post-tax measures of the WACC

To derive the pre-tax real WACC, EAPL has used an average of two alternative formulae which it has termed the forward and reverse transformation. The forward transformation involves grossing up the post-tax nominal WACC by the assumed taxation rate and then deflating the resulting pre-tax nominal WACC by the expected inflation (using the Fisher equation). The reverse transformation involves deflating the post-tax nominal WACC by the expected inflation (using the Fisher equation) and

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174 EAPL revised access arrangement information, 7 July 2003, p. 16.

175 EAPL revised access arrangement information, 7 July 2003, p. 16.

dividing this by one less the effective tax rate ($1-T_e$) (the formulae are contained in Table 2.6.5.1).

Effective tax rate

EAPL submitted that adopting the current company tax rate was appropriate because to apply effective tax rates, which incorporate the benefit of depreciation allowances and other tax benefits, would result in the 'confiscation of benefits consciously conferred by government thereby overriding government policy designed to promote investment'. [176]

Value of imputation credits

The adoption of a 0.5 value for imputation credits was, according to EAPL, in line with previous regulatory decisions. EAPL submitted that the study by Dr Martin Lally for the Commission which proposed a value of one lacked appropriate peer review. [177] EAPL added that although there were studies which focused on the rate of uptake of imputation credits, it was not aware of any study that measured the actual value placed on imputation credits by investors. EAPL concluded that to equate the uptake rate with value to investors would be likely to be flawed.

Capital structure

EAPL has proposed a gearing ratio which it submits is the industry standard structure and is consistent with the approach in the *Draft Decision*, and other regulatory decisions by the Commission, the ESC and IPART.

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[176] EAPL revised access arrangement information, 7 July 2003, p. 18.

[177] M. Lally, *The cost of capital under dividend imputation,* June 2002.

Table 2.6.5.1: Revised access arrangement proposed WACC parameters and estimates

Parameter		Value
General parameters:		
Real risk free rate 10 year bond rates	rr_f	3.35%
Inflation	F	2.69%
Nominal risk free rate r_f=1-(1+rr_f)(1+f)	r_f	6.13%
Gearing:		
Debt to total assets	D/(D+E)	60.0%
Taxation:		
Effective tax rate	T_e	30.0%
Value of imputation credits	γ	0.5
Return on equity:		
Asset beta	β_a	0.62
Debt beta	β_d	0.06
Equity beta $\beta_e = \beta_a + (\beta_a - \beta_d).(1-(rd/(1+rd)).(1-\gamma)T_e)D/E$	β_e	1.45
Market risk premium	MRP	6.0%
Nominal cost of equity $r_e = r_f + \beta_e (r_m - r_f)$	r_e	14.84%
Cost of debt:		
Debt margin	DM	1.20%
Nominal cost of debt $r_d = r_f$+DM	r_d	7.33%
Pre-tax real WACC		
Forward transformation $W_{tr} = [1+r_e.(1/(1-T_e.(1-\gamma))E/V + r_d.D/V]/(1+f)]-1$		8.46%
Reverse transformation $W_{tr} = [[1+(r_e.(1-T_e)/(1-T_e(1-\gamma)).E/V + r_d.(1-T)D/V)/(1+f)]-1]/(1-T_e)$		7.34%
Average of forward and reverse transformations		7.90%

Source: EAPL revised access arrangement information, 7 July 2003, pp. 16 and 19.

The cost of debt

EAPL calculated the nominal risk free rate by taking the 40-day average of the 10 year bond rate to 28 March 2002. EAPL contended that this approach was consistent with the Commission's approach in the *Draft Decision*.[178]

To derive the expected inflation rate over the access arrangement period, EAPL used the 40-day average of the five year bond rate to 28 March 2002 and the August 2005 Treasury indexed bonds. An inflation rate of 2.69 per cent was then estimated using the Fisher equation. EAPL reiterated its view that this approach was consistent with Commission's approach in the *Draft Decision*.[179]

The real risk free rate of 3.35 per cent was then calculated as the difference between the nominal risk free rate and the inflation rate (using the Fisher equation).

The return on equity

In relation to the market risk premium, EAPL submitted that there had been some recent studies which had estimated lower values for the market risk premium.[180] However, EAPL questioned the correctness of the results given the measurements used relatively short periods and consequently considered a limited lifecycle of risk. EAPL concluded that following the Productivity Commission's view about the deleterious impact of underestimating efficient costs, the adoption of a lower value should be avoided.

EAPL's estimation of an equity beta of 1.45 was calculated using the Monkhouse formula with a debt beta of 0.06 and an asset beta of 0.62.[181] According to EAPL, the 0.62 asset beta value reflects the pipeline's exposure to:[182]

- Increased competition from alternative energy sources;
- Increased competition from the EGP;
- Increased risk from the development of coal seam methane in NSW which would bypass the MSP. EAPL added that the recent market initiatives of Sydney Gas Company demonstrated that coal seam methane represents a genuine alternative source of gas for the Sydney market; and
- Uncertainties with deliverability from Moomba and the development of alternative gas sources. EAPL noted that this uncertainty exposed it to additional systematic as well as non-systematic risk.

EAPL also engaged NECG to respond to an empirical examination of the appropriate proxy equity beta for gas transmission businesses which was conducted by the Allen

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178 EAPL revised access arrangement information, 7 July 2003, p. 17

179 EAPL revised access arrangement information, 7 July 2003, p. 17

180 EAPL revised access arrangement information, 7 July 2003, p. 18.

181 $\beta_e = \beta_a + (\beta_a - \beta_d).(1-(rd/(1+rd)).(1-\gamma)T_e)D/E$

182 EAPL revised access arrangement information, 7 July 2003, p17 and EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 8.

Consulting Group (ACG) for the Commission.[183] In relation to the international comparative analysis contained within the report, the NECG asserted that this data 'is so equivocal that no useful inference can be drawn from it'.[184] As to the empirical estimates determined using a sample of Australian entities, NECG submitted that they suffered from selection bias as a result of both the temporal selection and the inclusion of imperfectly comparable firms. It stated 'it would be paradoxical indeed if the ACG estimate of multi-utility distribution and retail beta were given greater weight than the measured equity beta for the MSP's owner - the Australian Pipeline Trust'.[185] The NECG concluded that the ACG estimates 'represents an extreme low end of a range of possible beta estimates'.[186]

2.6.6 Submissions in response to the revised access arrangement

The EMRF noted that following the release of the Commission's *Draft Decision*, the ESC had published a Draft Decision for gas distribution businesses in which the pre-tax real WACC was set at 6.7 per cent.[187] The EMRF added that a submission made by BHP Billiton in response to GasNet Australia's proposed rate of return was also relevant to the current assessment. In particular, the EMRF noted BHP Billiton's statement that a pre-tax real WACC of less than 7 per cent was appropriate.[188] The EMRF stated that it concurred with BHP Billiton's views and regarded a report submitted by BHP Billiton in reference to the assessment of GasNet's access arrangement was also relevant to the MSP assessment.[189] The report (the Pareto report) formed part of the EMRF's submission.[190]

Briefly, the Pareto report compared the estimates for the cost of debt and the return on equity set by regulators in the UK and Australia. The report stated while estimates of the cost of debt are comparable across Australian and UK regulators there is a 'substantial divergence' between the regulators estimates of the return on equity, and that international integration has reduced the forward looking Australian equity premium below long term historical surveys.[191] The report stated that there appeared to be no reason to suggest why returns for Australian utilities should be higher than returns for UK utilities. It speculated that high returns may be the result of 'over

183 Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002.

184 NECG, *Response to ACG Report on Proxy Beta Estimates*, 4 November 2002, p. 4.

185 NECG, *Response to ACG Report on Proxy Beta Estimates*, 4 November 2002, p. 6.

186 NECG, *Response to ACG Report on Proxy Beta Estimates*, 4 November 2002, p. 8.

187 Energy Markets Reform Forum submission, 23 July 2002, p. 3.

188 Energy Markets Reform Forum submission, 23 July 2002, pp. 3-4.

189 Energy Markets Reform Forum submission, 23 July 2002, pp. 3-5.

190 Pareto Associates Pty Ltd, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK 'Vanilla' WACC Components,* July 2002.

191 Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, pp. ii and 9.

cautious' regulation or regulatory error, and that the WACC should provide the minimum necessary and no more than this.[192]

The report also recognised the usefulness of the CAPM as a method to determine expected returns but noted that its application requires the regulator to make a number of judgements relating to the value of parameters. It was suggested that Australian regulators may be unnecessarily conservative in these judgements relative to UK regulators, particularly with regard to:

- the market risk premium, with Australian regulators adopting values in the range 6 – 6.5 per cent compared to the 3 – 4 per cent values adopted by UK regulators;[193] and
- the equity beta, with Australian regulators adopting higher and more varied values for the equity beta in regulated decisions.[194]

EAPL's response to submissions on the revised access arrangement

EAPL requested the Commission to also take into account submissions on WACC received in response to BHP Billiton's submission and the Pareto report to the GasNet access arrangement review.

EAPL responded to a number of specific issues raised in the Pareto report including: the need to focus on the long term interests of users; the appropriateness of international comparisons; and the suggestion that regulators and policy makers (including the Productivity Commission) are 'susceptible' to the arguments put by regulated companies and their advisers.

On the first issue, EAPL submitted that there is no question that the interests of end-users are important, but stated that the long term interests of end users will be served best by the timely and efficient provision of adequate infrastructure services over the long term.[195] EAPL contended that the long term interests of users will not be accounted for if returns are driven down to the levels suggested in the report. In its view, regulators should look beyond the narrow short term concern of driving down prices, a factor which is recognised in section 2.24 of the Code.

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[192] Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, pp. 19-21.

[193] Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, p. 27.

[194] Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, p. 32.

[195] EAPL response to submissions, 25 September 2002, p. 6.

Second, in regard to international comparisons, EAPL submitted that such comparisons may be of interest but cannot be determinative and may only be partially relevant. EAPL added that NECG's response to similar comparative work carried out by NERA could, by extension, be applied to the work of Pareto. That is,

> …it would be very dangerous for any Australian regulator to revise its approach to setting the allowed rate of return merely on the basis that other regulators in other countries apparently allow investors in other businesses a lower return.[196]

Third, citing the Productivity Commission's legislation and the manner in which it conducts its reviews, EAPL rejected the suggestion that regulators and policy makers are 'susceptible' to the arguments put by regulated companies and their advisers.[197] EAPL noted that the Productivity Commission is an independent authority which is driven by concern for the wellbeing of the community as a whole. It concluded:

> The value of WACC determined by CAPM is a strong function of a number of input variables including equity beta and market risk premium and is widely acknowledged, including by Pareto, that there is no precise value for any of them – the actual value of WACC is uncertain. In the end, Regulators must apply appropriate judgement in determining the WACC to be recovered by a service provider. In the light of the strong position taken by NECG in its response to NERA (and, by extension to Pareto); the conclusions of the Productivity Commission; and the requirements of Clause 2.24 of the Code, we believe it would be an inappropriate and risky exercise of regulatory discretion to set the regulatory WACC at the lowest possible values, as espoused by the EMRF and Pareto.[198]

The Commission has assessed GasNet's response to the Pareto report as requested by EAPL. GasNet argued that the issues canvassed in the Pareto report were not new and that it had little to offer. GasNet asserted that erring on the low side of returns may bring immediate customer benefits, but those benefits would be outweighed by the costs associated with lower pipeline investment in the longer term. GasNet also argued that there was a reasonable level of consistency of the WACC decisions by the Commission, and that the main differences between the decisions appeared to be the level of the risk free rate and the value of the asset beta.[199]

GasNet also commented on international comparisons of the MRP (which was raised in the Pareto report). GasNet argued that adjustments must be made between countries when making comparisons and added that when adjustments are made to US data, the MRP is above 6 per cent. In addition, GasNet suggested that comparisons between the UK and Australian regulatory decisions may be problematic because the UK decisions have been made: under a very different set of rules; in relation to different entities; and in very different market conditions.[200]

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196 NECG, *International comparisons of rates of return*, 18 July 2001.

197 EAPL response to submissions, 25 September 2002, p. 8.

198 EAPL response to submissions, 25 September 2002, p. 8.

199 GasNet response to submissions on ACCC issues paper, 24 July 2002, pp. 19-20.

200 GasNet response to submissions on ACCC issues paper, 24 July 2002, p. 20.

2.6.7 Commission's considerations

The rate of return plays a fundamental role when determining revenues and as a result there is a substantial degree of sensitivity regarding its value. Consistent with section 8.30 of the Code, the Commission's approach is to consider whether the service provider's proposed rate of return is commensurate with prevailing conditions in the market for funds and the risks involved in delivering the reference service.

Section 8.2(e) provides further guidance on this aspect in that it requires the Commission to consider whether the forecast rate of return and the forecast values of the individual parameters underlying this rate of return, in fact represent best estimates arrived at on a reasonable basis.

The Commission recognises that there may be instances where a range of values have the quality required by section 8.2(e) (for example a confidence interval). In these circumstances the Commission will have recourse to the reference tariff principles set out in section 8.1 of the Code and, if these objectives conflict, consideration will then be given to the factors set out in section 2.24 of the Code.

Where relevant the Commission has used financial market benchmarks when assessing the proposed rate of return. The Commission considers that the use of such benchmarks is consistent with section 8.30 of the Code (which requires the return to be commensurate with prevailing market conditions in the market for funds) and, in appropriate cases, with section 8.2(e). The Commission also considers the use of financial market benchmarks to be consistent with section 8.1 of the Code, which states that reference tariffs and reference tariff policy should be designed to:

- provide the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service (section 8.1(a));
- replicate the outcome of a competitive market (section 8.1(b));
- achieve efficiency in the level and structure of the reference tariff (section 8.1(e)); and
- provide an incentive for the service provider to reduce costs and to develop the market for reference and other services (section 8.1(f)).

The use of benchmarks is also consistent with section 8.2(d) (and sections 8.44 - 8.46) which prescribes the use of incentive mechanisms wherever the regulator considers it appropriate and where they are consistent with the principles in section 8.1.

In relation to international benchmarks, the Commission considers that, while such information is useful as a secondary source, caution must be exercised in interpreting the information particularly given the number of adjustments and assumptions required for differences in financial markets and institutional arrangements between markets. The Commission notes that specific differences that need to be taken into account when comparing WACC parameters across countries include:

- differences in the size and composition of share markets;[201]

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[201] ESC, *Final Decision: Review of gas access arrangements*, October 2002, p. 370.

- varying taxation regimes between countries;[202]
- differences in market average levels of gearing;[203] and
- diverging incentive mechanisms and regulatory approaches.

These factors have formed the basis for the Commission's consideration of the 7.9 per cent pre-tax real WACC proposed by EAPL. Before examining the parameters underlying this proposed rate of return, it is necessary to consider EAPL's proposal to use a pre-tax framework. Following the assessment of the various CAPM parameters an overall examination of the WACC concludes this section of the *Final Decision*.

2.6.7.1 Pre-tax versus post-tax measures of the WACC

Derived using a number of parameters and assumptions, the WACC is a measure of the total cost of capital, with the cost of debt and return on equity weighted in accordance with the capital structure. The WACC may be expressed on a post-tax, pre-tax or vanilla basis and within a nominal or real framework. Under the post-tax approach, tax liabilities are compensated through the cash flows. In contrast, the pre-tax approach contains an allowance in the rate of return to cover tax liabilities. The vanilla WACC is a hybrid of the two with the return on equity defined in post-tax terms and the cost of debt in pre-tax terms.

EAPL has proposed the use of the pre-tax real WACC derived using the average of two alternative formulae which it has termed the forward and reverse transformations. As outlined previously, the forward transformation involves grossing up the post-tax nominal return on equity by the assumed effective tax rate and then deflating the resulting pre-tax nominal WACC by the expected inflation (using the Fisher equation). The reverse transformation involves deflating the post-tax nominal WACC by the expected inflation (using the Fisher equation) and dividing this by one less the effective tax rate ($1\text{-}T_e$).

In carrying out these transformations EAPL has adopted the company tax rate as a proxy for the effective tax rate. EAPL has argued that application of the effective tax rate (that reflects the benefits of depreciation allowances and other tax policy initiatives of the government) would not be appropriate. According to EAPL the use of the effective tax rate would result in the 'confiscation of benefits consciously conferred by government thereby overriding government policy designed to promote investment'.[204]

Problems with the transformation formulae

As set out in the *Draft Decision*, the Commission does not consider either of the real pre-tax transformation formulae proposed by EAPL to be valid. The issue of the validity of the pre-tax transformation formulae was considered in detail in the 1998

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202 ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities: Final Report,* July 2002, p. 19.

203 ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities: Final Report,* July 2002, p. 19.

204 EAPL revised access arrangement information, 7 July 2003, p. 18.

Victorian Final Decision[205] and subsequently within the *DRP*.[206] This consideration resulted in the following observations:

- since the effective tax rate depends on the rate of inflation, a simple procedure to adjust first for the effective tax rate and then for inflation (the forward transformation) does not necessarily correctly estimate the pre-tax real WACC;
- the reverse transformation is compromised by the interaction between the effective tax rates and anticipated inflation and therefore yields an incorrect estimation of the pre-tax real WACC; and
- the level of bias in both the forward and reverse transformations depends on the assumptions used concerning the real cost of debt, gearing, the utilisation of imputation credits and inflation.

Accordingly, the Commission concluded that neither the forward nor the reverse transformations yielded the return to investors suggested as appropriate by the CAPM. In the 1998 Victorian Final Decision the Commission used cash flow modelling to derive the pre-tax real WACC that yielded the post-tax nominal return on equity indicated by the CAPM as the return over the lifetime of the assets.

It has therefore been the failure of these transformation formulae to yield a rate of return which is consistent with CAPM that has led the Commission to conclude that these formulae are flawed. Consequently, the Commission is not confident that a rate of return calculated in accordance with this approach would be commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (section 8.30).

While different regulators have applied several incompatible variations of the transformation approach, none have yielded results which are consistent with what might be viewed as reasonable cash-flow simulation of tax liabilities. The post-tax analysis avoids any of the transformation formulae as a basis for assessing the amount of compensation for tax to be added to the post-tax revenue estimates or for determining the rate of return. The Commission therefore considers the post-tax framework is more likely to lead to a rate of return which is appropriate in light of section 8.30.

Associated problems with the pre-tax approach

In addition to the issues discussed above in relation to the transformation formulae, the use of a pre-tax framework also gives rise to a number of problems. These include the need to take account of and estimate the effective tax rate. This requires estimates of future tax liabilities and inflation over the life of the assets, both of which are sources of considerable uncertainty.

EAPL has tried to circumvent these problems by simply adopting the company tax rate as a proxy for the effective tax rate. However, the use of the company tax rate ignores

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205 ACCC, *Final Decision: Victorian Access Arrangements*, 6 October 1998, p. 61 and Appendix E.

206 ACCC, *DRP*, May 1999, pp. 73-75.

the existence of important aspects of tax legislation which may cause the effective tax rate to differ substantially from the company tax rate.

An entity's ability to access accelerated depreciation for tax purposes may mean that tax depreciation differs from actual depreciation resulting in an excess tax allowance in the early years and a considerable deferral of tax liabilities. The deferral of tax liabilities means that initial post-tax cash flows will be elevated resulting in a more rapid recovery of capital and an internal rate of return greater than might otherwise be the case.

Thus, the inclusion of the company tax rate in any formula used to derive the pre-tax WACC is likely to result in an overstatement of the effective tax rate and in turn an overstatement of the required return on equity. As a result the rate of return estimated would fail to reflect the return which is commensurate with prevailing conditions in the market for funds and the risks involved in delivering the reference service (section 8.30).

The Commission also disagrees with EAPL's assertions that taking into account accelerated depreciation and other tax policy initiatives of the government is inappropriate. Specifically, the Commission considers EAPL's view fails to appreciate that the regulatory framework provides a benchmark return required by investors, and that investors benefit from accelerated depreciation in the same way as if the company was regulated. This is apparent when observing what happens to an investor's post-tax returns in the case of a non-regulated firm. Suppose that the revenues provide a cash flow benefit to the firm of $X before tax and the company pays $T in tax leaving investors with $(X-T) in cash flow returns after tax. However, the dividend imputation system (which is discussed below), provides Australian investors with a credit restoring their effective return to $X. With accelerated depreciation, the timing of company tax payments is deferred and their NPV is reduced but the effective returns to the Australian investor are unchanged given that there is no impact from taxation. The regulator's assessment of taxation recognises imputation and accelerated depreciation and therefore has a similar impact on the unregulated firm.

This is not to say that government taxation policy does not benefit the gas industry. The combination of imputation credits and accelerated depreciation means that regulatory revenues are reduced through lower tax liabilities while allowing investors to maintain market commensurate returns. Users therefore benefit through lower prices and service providers from higher demand.

Some classes of investors benefit more than others. For example, foreign investors who receive minimal benefit from imputation credits do benefit from accelerated depreciation while Australian investors, who benefit from imputation, receive no additional benefits from accelerated depreciation. These different classes of investors receive the same benefits as they would if their assets were regulated. In applying the regulatory framework to date the Commission has assumed on average investors are unable to fully utilise the available imputation credits. This has the effect of sharing the benefits of accelerated depreciation and imputation with investors (who are compensated for some tax payments) and users (through lower revenue requirements). As the regulatory framework gives an outcome reflective of a competitive market but returns to different classes of investors that are affected in the same way as they would be if the assets were not regulated. Consequently, the Commission considers that the use of the effective tax rate (which takes into account accelerated depreciation) meets both the objectives of section 8.30 and 8.1 of the Code as well as the objectives of government industry policy.

Another issue associated with the pre-tax approach is the potential for the S-bend problem to arise.[207] This may occur because the pre-tax approach provides for a fixed proportion of the return on capital to provide compensation in the revenue stream for current and future tax liabilities. However, because of a range of tax concessions there is generally very little tax payable early in the life of an asset, and tax liabilities increase significantly later in the life of the asset after the tax concessions have been fully utilised. These timing effects will in later years result in tax liabilities greatly exceeding the provision for them. This may in turn impact upon investment in the pipeline or on the safe and reliable operation of the pipeline. Alternatively, it may result in 'double dipping' with users compensating the service provider a second time. Any of these outcomes would result in tariffs over the life of the assets failing to meet the objectives set out in section 8.1 of the Code.

Perhaps the most obvious problem with the pre-tax approach is that it attempts to compensate for tax liabilities that will not occur until well into the future. As a result it is subject to considerable uncertainty stemming from inflation effects and changing tax legislation. This introduces a level of uncertainty into the cost of capital estimated that does not need to be borne.

Given the shortcomings and problems associated with the pre-tax formulae and the pre-tax approach, the Commission has emphasised, since the Victorian Final Decision, its preference for the post-tax approach to measuring the rate of return.[208] That is to apply the vanilla WACC[209] (which is the required rate of return on assets if no company tax is payable) to the capital base and to compensate benchmark tax liabilities and imputation credits explicitly and in a transparent manner through the cash flows when they are calculated to arise. The Commission considers this approach is the best and most reasonable basis upon which the rate of return can be forecast (section 8.2(e)) and is the approach most likely to lead to a rate of return which will be commensurate with the market for funds and the risk involved in delivering the reference service (section 8.30).

In support of this position the Commission notes that the explicit compensation for tax liabilities effectively eliminates the need to calculate a tax wedge and a long term effective tax rate. While assumptions regarding tax legislation and inflation are still required, they are only needed to be made over the access arrangement period rather than the life of the assets. Thus, the approach overcomes the problems associated with estimating these parameters. This approach also allows for the estimation of the pre-tax real WACC through the simulation of expected cash flows over the life of the asset. This estimation is equivalent to having available the correct conversion formula for the

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207 ACCC, *Final Decision: CWP*, Appendix C.

208 ACCC, *Final Decision: Victoria 1998*, p. 61 and Appendix E.

209 Vanilla WACC = $r_e.E/(D+E)+r_d.D/(D+E)$
(where r_e is the post-tax return on equity and r_d is pre-tax cost of debt).

pre-tax real WACC (if an analytical expression of such a formula exists) and consequently overcomes the problems associated with the transformation formulae.[210] The explicit compensation for tax also avoids the potential for incorrect compensation for future tax liabilities and an under or over recovery of revenue over the life of the assets. As far as the service provider is concerned, the post-tax approach removes any risks associated with future tax liabilities by ensuring full compensation for tax liabilities over the access arrangement period.

The Commission has assessed EAPL's claims regarding the pre-tax approach. While the Commission acknowledges that cash flow modelling is not as simple as the application of the pre-tax formulae it considers, for the reasons noted above, that the pre-tax transformation formulae result in a rate of return which is inconsistent with section 8.30 of the Code. Accordingly, the Commission considers that the post-tax framework is the approach most likely to lead to a rate of return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (section 8.30).

Thus, the Commission has utilised the post-tax approach to assess EAPL's proposed revenue and tariffs over the coming access arrangement period. In doing so the Commission has applied the vanilla WACC to the capital base with tax liabilities and imputation credits being compensated explicitly through the cash flows. While the modelling of tax and imputation credits explicitly removes the effect of tax on the rate of return the cash flow modelling requires some assumptions to be made with regard to:

- benchmark tax liabilities;
- the initial tax position;
- depreciation rates;
- the company tax rate; and
- the value of imputation credits.

The Commission's assumptions with respect to these aspects are set out briefly below.

Tax related issues

The Commission considers that a key objective in determining the allowance for taxation is that it reflects an unbiased estimate of tax liabilities for an efficient company. A number of the inputs required to deduce likely tax liabilities for the regulated operations are readily available from the regulatory framework, namely:

- assessable revenue – assumed to be the benchmark revenue;
- operating expenditure – assumed to be the forecast operating expenditure;
- capital expenditure – taken to be forecast capital expenditure; and
- interest expenses – taken as the nominal interest payments implied by the benchmark financing arrangements (in particular the gearing ratio).

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[210] ACCC, *DRP*, May 1999, p. 75.

The remaining information required includes: the tax position of the regulated business at the start of the access arrangement period; information to determine depreciation allowances for taxation purposes; an assumption regarding the company tax rate; and an assumption regarding imputation credits facing the benchmark firm.

The initial tax position of the firm is essentially defined by two variables: the written down value of the assets for tax purposes and the carried forward tax loss which can be offset against future income to diminish future tax liabilities. The written down value of the assets at the start of the access arrangement period is required to determine the amount of tax depreciation that can be assigned to reduce assessed income and hence the associated tax liability. A carried forward tax loss is incurred when previous tax depreciation results in assessable income being negative. This negative carryover can be offset against positive income and tax liabilities in future periods.

EAPL has not provided information relating to the opening tax value of assets and the carried forward tax loss in its model or access arrangement information. Accordingly, the Commission has had recourse to EAPL's financial statements in order to determine the written down value of EAPL's assets. In doing so the Commission has assumed that EAPL's carry forward tax loss is equivalent to zero and adjusted the written down value of the assets accordingly. This written down value is then used to establish the availability of tax depreciation which can be accessed in future years.

Assumed depreciation for tax assessment purposes represents another important element for the determination of benchmark tax liabilities. Government tax legislation relating to accelerated depreciation means that tax liabilities can be deferred for a significant period, which influences the amount of tax payable by the firm through the life of the asset. As with the written down value of assets and the carried forward tax loss, EAPL has not provided the Commission or interested parties with information pertaining to depreciation rates or the method assumed for each type of asset class which constitutes the pipeline. Given these omissions, it has been assumed for the calculation of tax liabilities that EAPL is able to depreciate all pipeline assets over 20 years. The Commission notes that this assumption reflects current tax rules relating to accelerated depreciation. The Commission has also assumed that the current company tax rate of 30 per cent will apply over the access arrangement period.

An estimation of the tax liabilities may be made in light of these assumptions. As stated previously, the effective tax rate is not required as an input for the determination of regulated revenues within the post-tax framework (although it does play an insignificant role in the calculation of the equity beta using the Monkhouse formula). Rather, the required return on capital is generated independently of the effective tax rate. The effective tax rate may still, however, be estimated in the post-tax framework by simulating cash flow expectations over the life of the asset and comparing the post-tax return on equity (r_e) determined through the CAPM with the pre-tax return on equity derived through the cash flows (r_{te}) using the relationship below (where T_e is the effective tax rate)

$$r_e = r_{te}.(1\text{-}T_e)$$

The Commission has carried out its own cash flow analysis to determine the revenues and the appropriate WACC for the mainline and regional segments of the MSP. This analysis suggests that for existing assets the effective tax rate looking forward for equity is approximately 23.5 per cent for the mainline and approximately 13.8 per cent for the regional segment of the MSP. In contrast to many other pipelines whose effective tax rates are well below the company tax rate, the effective tax rate for the MSP is relatively close to the company rate. This is an outcome of the utilisation of accelerated depreciation to minimise tax liabilities since EAPL's purchase of the pipeline in 1994. Had the assessment been done in 1994 when the assets had not been depreciated for tax purposes the forward looking effective tax rate would have been much lower.

The EUAA recommended that the Commission give further consideration to the issue of the effective tax rate. Specifically, the EUAA noted that the Commission accepted an effective tax rate of 34 per cent for 2000/01 and a rate of 30 per cent thereafter in its *Draft Decision*, but it considers that a more appropriate measure of taxation would be the actual rate paid since the purchase of the business in 1994 and forecast tax rates for the access arrangement period.[211] The Commission acknowledges the concerns of EUAA, but notes that effective tax rates of 34 and 30 per cent respectively were not employed in the *Draft Decision*. The company tax rates of 34 per cent and 30 per cent were only used to determine tax liabilities through cash flow modelling and to smooth (or normalise) revenues given higher tax payments in future regulatory periods. As foreshadowed above, the Commission has maintained its cash-flow approach to determining tax liabilities in this *Final Decision.* That is, company tax rates are not used as a proxy for the effective tax rate. Moreover, the effective tax rate is not required as an input for the determination of regulated revenues within the post-tax framework.

The value of imputation credits

A further factor that must be taken into account in either the pre-tax or post-tax derivation of the WACC is the benefit accorded to shareholders through the dividend imputation system. The dividend imputation system in Australia operates to compensate shareholders for the tax paid out of company earnings through the distribution of imputation credits. The system recognises that tax paid by the company represents a pre-payment of personal income tax on dividends, thereby providing some value to shareholders. This value may in turn result in the actual after-tax return required by shareholders, as calculated through CAPM, to be overstated.

Thus, the availability of tax imputation credits requires a modification to the standard CAPM and WACC models to reflect the return to shareholders of tax credits associated with their share dividends. This modification is carried out through the introduction of gamma (γ), which measures the proportion of imputation credits which can, on average, be utilised by shareholders of the company to offset tax payable on other income. The value of gamma lies between zero and one, with a gamma of zero signifying the absence of any utilisation, while a gamma of one represents full utilisation. A higher gamma therefore reduces the required return on equity and in turn the WACC. As a consequence, the value accorded to the parameter has been the source of much debate.

211 EUAA submission to the Draft Decision, 21 February 2001, p. 2.

The standard practice adopted by the Commission and other Australian regulators is to treat imputation credits as an offset to the entity's corporate taxation liability. This approach implies that if a regulated entity faces tax liabilities of $T for a given financial year then the regulated entity would only require an allowance of (1-γ).$T to meet these liabilities. The remaining portion (γ.$T) would then be paid to shareholders through the imputation system. Consistent with the Commission's post-tax approach, the value of gamma is accounted for in the cash flows.

It should also be noted that gamma has a minor role in the Monkhouse levering formula used to determine the equity beta from the asset beta. However, in practice the impact on the equity beta is very small and insignificant in the context of revenue determination.

The value of gamma to an investor largely depends on whether:

- imputation credits are made available to investors by attaching them to dividend payments from the entity; and
- the investor is fully able to utilise the value of the credit which will depend on whether the investor has taxable income within Australia that it can use the imputation credits to offset pursuant to the prevailing tax legislation.

In relation to the first point, it would appear to the Commission that there would be no benefit for a company to retain imputation credits any longer than necessary. The second point raises two issues, these being the relevant tax legislation and the investor's country of residence. With regard to the first aspect, the Commission notes that as a result of changes to the Australian tax system, Australian residents and complying superannuation funds, who may not have previously been able to receive the full benefit of imputation credits, can now do so.[212] As to the second aspect, the Commission has to date assumed that that the relevant benchmark for regulatory purposes is the assumption that the average equity investor is domiciled in Australia. This assumption ensures consistency in applying the CAPM in the context of the Australian market.[213]

The Commission's assumption regarding the segregation of the Australian market has also been advocated by Dr Martin Lally.[214] In a paper prepared for the Commission, Lally considered the issue of the relevance of foreign investors in detail and concluded that:

> …continued use of a version of the Capital Asset Pricing Model that assumes that national equity markets are segmented rather than integrated (such as the Officer model) is recommended. It follows that foreign investors must be completely disregarded.

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212 Resident individual investors receive the full benefit regardless of their tax position, as franking credits are now treated as a refundable rebate rather than as a tax deduction. Complying superannuation funds are preferentially taxed, which in the past, may have resulted in imputation credits being eroded. Under the new tax system, franking credits are paid to the fund as a rebate from the Australian Tax Office.

213 If this assumption were to change then modifications would have to be made to a number of other parameters including the market risk premium and the equity beta.

214 M. Lally, *The cost of capital under dividend imputation,* June 2002.

> Consistent with the disregarding of foreign investors, most investors recognised by the model would then be able to fully utilise imputation credits.[215]

Lally recommended that the ratio of imputation credits assigned to company tax paid should be set at the relevant industry average. Having recourse to the imputation credit/tax ratio of the eight largest listed entities in Australia[216], Lally concluded that the ratio of imputation credits to tax is close to one for most industries.[217]

To the extent that there were a significant proportion of foreign investors who could not fully avail themselves of the imputation credits, Lally suggested that it was not appropriate to change just one parameter in the CAPM. Instead, Lally advocated the application of an international version of the CAPM where the CAPM parameters would be based on international financial markets. Under this approach Lally showed that the cost of capital for foreign investors was less than for investors with a domestic focus and the domestic investor assumption did not compromise the position of foreign investors. The culmination of these two recommendations and the analysis regarding foreign investors led Lally to conclude that the product of the utilisation rate and the ratio of imputation credits assigned to company tax paid (gamma) should be at, or close to, one for most companies.

In reference to all the information available to the Commission relating to imputation credits, the Commission considers that there are good arguments that the value of gamma should be one. However, it also acknowledges that further debate in this area is desirable, particularly in light of the recent work undertaken by Lally. Accordingly, for current regulatory purposes the Commission considers that a value of gamma equal to 0.5 would sit at the far extreme of the range that has the quality required by sections 8.30 and 8.2(e) of the Code.

The extent to which a gamma of 0.5 would promote the objectives contained in section 8.1 is at this stage unclear. According to Lally a value of gamma less than one would: result in reference tariffs being inefficient in both level and structure; result in EAPL earning a stream of revenue that exceeds the efficient costs of delivering the services; the failure to replicate the outcome of a competitive market; have the potential to distort investment decisions in both the MSP and in upstream or downstream industries; and fail to provide EAPL with an incentive to reduce costs. However, it could also be argued that a value of one may result in: EAPL failing to recover the efficient costs of delivering the reference service; the safe and reliable operation of the pipeline being affected; and investment decisions in the pipeline being distorted.

In view of this uncertainty, the Commission has decided to accept EAPL's proposal as being consistent with both section 8.2(e) and section 8.30 of the Code and notes that this is consistent with the *Draft Decision* and other recent regulatory decisions. After taking into account the factors set out in section 2.24 of the Code, particularly EAPL's

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215 M. Lally, *The cost of capital under dividend imputation,* June 2002, p. 43.

216 The eight entities referred to were: Telstra, News Corporation, National Australia Bank, BHP Billiton, Rio Tinto, Westpac, Commonwealth Bank and ANZ.

217 The evidence for payout of imputation credits is discussed in M, Lally, M. Lally, *The cost of capital under dividend imputation,* June 2002, p. 19.

legitimate business interests (section 2.24(a)), the interests of users and prospective users (section 2.24(f)) and the public interest (section 2.24(e)), the Commission considers that a conservative approach to establishing gamma is currently appropriate. The Commission recognises that in reaching this position it has adopted a relatively conservative approach to the benefit of EAPL.

Nevertheless, the Commission notes that it may revise its view on the value of the gamma parameter in the future as additional information and market evidence becomes available.

2.6.7.2 Capital structure

To determine the appropriate weighted average cost of debt and equity in the WACC framework, the value of debt and equity as a proportion of an organisation's total value are required. The Modigliani-Miller theorem suggests that the cost of capital should, in the absence of taxes, be invariant over a broad range of gearing levels.[218] Furthermore, this theorem holds approximately true in the presence of taxes due to offsetting channels such as the equity beta. Consequently, the gearing assumption used for the determination of WACC should not be a critical one.

Accordingly, the Commission is of the view that EAPL's proposed debt to equity ratio of 60:40 is reasonable for the purpose of deriving the WACC and consistent with section 8.30 of the Code. In reaching this view the Commission notes that the proposed ratio is consistent with other regulatory decisions and reflects a standard industry structure as can be seen in the Table 2.6.7.1.

Table 2.6.7.1: Gearing levels for the 2002 financial period

Company	Total Debt/Assets (%)
AGL	52.2
Alinta Gas	49.2
APT	66.6
Envestra	79.9
GasNet Australia	67.2
United Energy	49.2
Average	**60.7**

Source: Standard & Poor's, *Australia & New Zealand CreditStats 2003*, June 2003, pp. 31-32.

218 Modigliani and Miller establish that the value of the company is unaffected by its choice of capital structure using the principle of 'no arbitrage'. This principle states that assets that offer the same cash flow must sell for the same price. Thus, a company's borrowing decision does not affect either the expected return on the company's assets or the required return on those assets.

2.6.7.3 The cost of debt

The cost of debt in the WACC formulation is the expected return to debt holders on debt capital invested (r_d) and is calculated as the sum of the nominal risk free rate (r_f) and the cost of debt margin (DM). That is:

$$r_d = r_f + DM$$

Risk free rate

The risk free rate forms the basis for estimating the rate of return (for both debt and equity). Specifically, the risk free rate measures the return an investor would derive from an asset with certainty of return being achieved. The risk free rate cannot be observed directly, but can be approximated by the yield to maturity on government bonds. Government bonds are viewed as a proxy for risk free assets because they provide investors with a guaranteed income and return of capital given that the government is in a position to honour all interest and debt repayments. The use of government bonds is generally accepted as a proxy for the risk free rate and has been proposed by EAPL in its revised access arrangement.[219]

Government bonds issued in Australia are either nominal or real. A nominal bond provides a fixed payment to the investor. If inflation is higher (lower) than expected by the investor, then the real income received by the investor will be lower (higher) than was expected. A real or inflation-indexed bond adjusts the payment to the investor to the Consumer Price Index (CPI), meaning that the dollar amount of the payment varies in line with inflation, ensuring that the income is maintained in real terms. The regulatory framework set out under section 8.5A of the Code is designed to account for the effects of inflation, meaning that the real risk free rate measured by inflation-indexed bonds is the important variable in the determination of the rate of return. The nominal risk free rate is still important as it can be used in conjunction with the real rate to determine market expectations of inflation and maintain consistency in the cash flow analysis with nominal market expectations.

The Australian Government usually issues new series of nominal bonds once or twice a year with a term of around 10 years.[220] The rate on nominal bonds to maturity provides a proxy for the nominal risk free rate over that same period. The Australian Government has also issued a limited number of series of real bonds with maturities running through to August 2005, 2010, 2015 and 2020. The implied yield to maturity of these bonds provides a proxy for the real risk free rate over that period.

Term of the risk free rate

While the use of government bonds for the risk free rate is widely accepted, the actual term of the government bonds used as a proxy for the risk free rate when applied in the context of calculating the cost of debt or the cost of equity from the CAPM is a contentious issue. In its revised access arrangement, EAPL proposed using a 10 year bond rate as the basis of the nominal risk free rate, and have calculated the real risk free rate as the difference between this nominal risk free rate and the inflation rate. The

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[219] EAPL revised access arrangement information, 7 July 2003, p. 17.

[220] Recently the Australian Government has issued nominal bonds with 13 year maturities.

inflation rate used is based on the difference between five year nominal government bonds and the August 2005 series of Treasury indexed bonds using the Fisher equation.

The Commission considers there are a number of issues bearing negatively upon the extent to which EAPL's proposed methodology would lead to a rate of return consistent with section 8.30. These are:

- The proposed 10 year risk free rate is likely to differ from the rate matching the access arrangement period (five years). This is because:
  - the market adds a liquidity premium to the longer term bonds to compensate for the increased risk the investor is taking in committing to a longer period; and
  - the market may expect interest rates after the maturity of the short bond (years 6-10) to be higher (or lower) than those during the period of the shorter bond (years 1-5).
- The proposal to estimate the real risk free rate based on the inflation rate is imprecise. As noted, EAPL proposes to determine the inflation rate based on the difference between five year nominal government bonds and the August 2005 Treasury indexed bonds series. This is problematic as it seeks to compare rates of return on bonds with substantially different maturity dates. That is, five year nominal bonds have a significantly different term from the 2005 series of Treasury indexed bonds.
- Under the terms of the Code, the total revenue and tariffs for a pipeline are reviewed every access arrangement period. Consequently, an investor does not need to be compensated for risk longer than that period. If the 10 year bond period is used, EAPL would be compensated for bearing a risk that it does not face. Further, the interest rate changes in years 6 to 10 built into the 10 year rate are irrelevant. The use of 10 year rates would lead to revenues that are sometimes too large and sometimes too small.[221]

Thus, the proposal to use 10 year bonds to determine the nominal risk free rate will result in either an over or under compensation for the service provider. Similarly, determining the real-risk free rate based on 10 year rates less forecast inflation as proposed by EAPL will also lead to estimated returns that do not match market expectations for the access arrangement period.

In general, the Commission considers that the nominal risk free rate should be calculated using nominal Commonwealth bond series data which matches the regulatory period, and that the real risk free rate should be based on inflation-indexed bonds also matching that period. The use of an interest rate whose maturity matches the regulatory period ensures the expected cash flows are fairly priced in net present value terms. That is, using rates linked to the regulatory period is, in the Commission's view, more likely to result in a rate of return which is commensurate with the market conditions for funds and the risks involved (section 8.30). Where government bond series matching the end of the regulatory period are not available, the Commission

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221 This argument is made by Lally, M., *Determining the risk-free rate for regulated companies: Prepared for the ACCC*, August 2002.

considers that the most precise estimate will be achieved through undertaking a linear interpolation of the two closest bond series.

This approach is consistent with numerous gas access arrangement decisions. In the GasNet Final Decision and the MAPS Final Decision, real and nominal bond rates matching the five year access arrangement periods were used.[222] In the ABDP Final Decision and the CWP Final Decision the Commission used bond series which matched the 10 year access arrangement periods proposed.[223] Rates matching the five year access arrangement period were also adopted in the *Draft Decision*.[224] The Commission therefore notes that EAPL's claim that the methodology used to determine the nominal and real risk free rate is 'consistent with the Commission's approach in the *Draft Decision*'[225] is not entirely accurate.

Measurement period

In its revised access arrangement information, EAPL proposed calculating the nominal risk free rate by taking the 40-day average of the 10 year bond rate to 28 March 2002 and the real risk free rate based on nominal and indexed bond data averaged over the same period.

The Commission considers that EAPL's proposal to use a 40-day average of the risk free rate is within the range of variables which satisfies the principles set out in section 8.30 and 8.2(e) of the Code. While the on-the-day rate is theoretically the most appropriate rate to use, a 40-day average may overcome any unanticipated market volatility that may occur over a shorter measurement period and provide a greater degree of certainty. The Commission has adopted a 40-day averaging approach in a number of decisions, including the *Draft Decision.*[226]

However, the Commission considers that EAPL's proposal to end the averaging period on 28 March 2002 will not provide the best estimate (in accordance with section 8.2(e)) in circumstances where more recent data is publicly available. Given that bond rate data is published daily by the Reserve Bank of Australia, the Commission is of the view that bond rate data used should be as up-to-date as possible, subject to constraints imposed by the decision making process.[227] Accordingly, the Commission has adopted a 40-day moving average of bond rates to 17 September 2003.

Based on the methodology outlined above, the average 40-day inflation-indexed bond rate is 3.0 per cent, and the average 40-day nominal bond rate is 5.3 per cent.

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222 ACCC, *Final Decision: GasNet*, pp. 85-89 and ACCC, *Final Decision: MAPS*, pp. 37-39.

223 ACCC, *Final Decision: ABDP*, pp. 78-80 and ACCC, *Final Decision: CWP*, pp. 17-21.

224 ACCC, *Draft Decision: MSP*, pp. 73-74.

225 EAPL revised access arrangement information, 7 July 2003, p. 17.

226 ACCC, *Draft Decision: MSP*, 19 December 2000, p. 73-74. See also ACCC, *Final Decision: GasNet*, 13 November 2002, p. 88 and ACCC, *Final Decision: ABDP*, 4 December 2002, p. 79.

227 For example, see: ACCC, *Draft Decision: MSP*, 19 December 2000, p. 74.

Table 2.6.7.2: Current financial market interest rates and inflation expectations

Bond rates interpolated to 31 December 2008	40-day moving average to 17 September 2003[(a)] (%)
Estimated 5 year inflation indexed government bond rate	3.0
Estimated 5 year nominal government bond rate	5.3

Note: (a) Based on indicative mid rates of Australian Government Securities published daily by the Reserve Bank of Australia

Inflation

In its revised access arrangement information, EAPL calculated forecast inflation by reference to financial market data. Specifically, EAPL calculated the difference between the five year nominal bond rate and the August 2005 Commonwealth Treasury indexed bond rate using the Fisher equation. EAPL has measured these rates by taking the 40-day average to 28 March 2002.

The Commission considers that broadly the approach to establishing expected inflation as proposed by EAPL complies with sections 8.30 and 8.2(e) of the Code. It is common practice among financial practitioners to estimate long term inflation using the difference between real and nominal bond data determined through the Fisher equation.

However, as noted above the mismatch between the maturities of the nominal and real bond series used introduces an unnecessary compromise in accuracy. Accordingly, while EAPL has proposed using the five year nominal bond rate, the Commission considers that it is appropriate under section 8.2(e) of the Code to interpolate this rate through to the anticipated end of the access arrangement period. Similarly, real rates should be calculated by interpolating August 2005 and August 2010 inflation-indexed bond rates to match the estimated end of the regulatory period.

Also as noted with regard to the risk free rate, the Commission has some concerns with EAPL's proposed measurement period. While the use of a 40-day averaging period is not disputed, the Commission is of the view that in order to comply with sections 8.30 and 8.2(e) of the Code, rates should be as current as possible subject to constraints imposed by the decision-making process. Accordingly, instead of ending the averaging period on 28 March 2002, the Commission has adopted a 40-day moving average of bond rates to 17 September 2003.

Using this approach, the market-inferred expectation of inflation for the initial access arrangement period is 2.19 per cent.

Debt margin

Assessment of EAPL's proposal against Code requirements

As noted earlier, the Commission proposed a debt margin of 1.20 per cent in the *Draft Decision*. However, the debt margin operating in the economy fluctuates over time. Moreover, further data on the cost of debt (through which the debt margin can be deduced) has been published. Consequently, the Commission considers that adhering to the assumption of 1.20 per cent will generate a result which would not reflect the prevailing conditions in the market for funds as required under section 8.30 and would not generate the best estimate in accordance with section 8.2(e). The Commission is of the view that a debt margin arrived at through reference to current market data better satisfies the requirements of the Code.

Current market data can refer to either the actual debt margin facing the regulated firm or the debt margin facing a transmission companies more generally. The Commission considers that it is appropriate to refer primarily to the latter because:

- The actual cost of debt may not reflect the efficient finance sourcing consistent with other financing assumptions made in the Final Decision. For example, EAPL has proposed a WACC based on a gearing ratio of 60:40. If EAPL's actual gearing ratio is higher (lower) than this assumption, then the actual cost of debt incurred by EAPL is likely to be higher (lower) than that incurred by a benchmark firm operating with a 60 per cent level of debt. That is, the use of benchmarks for one WACC parameter necessitates the need to use benchmarks for other parameters in order to ensure that internally consistent market reflective efficient outcomes are achieved.
- A primary focus on transmission companies generally (rather than on the particular position of the firm in question) is more likely to lead to rate of return commensurate with the prevailing conditions in the market for funds (section 8.30 of the Code).
- This approach is consistent with section 8.31 of the Code which states that the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice.
- This methodology also satisfies section 8.2(e) of the Code which states that any forecasts required to set reference tariffs represent best estimates arrived at on a reasonable basis.
- The reference to transmission companies generally (rather than the position of the firm in question) should provide an incentive for the service provider to establish least cost financing arrangements within the access arrangement period. This is consistent with sections 8.2(d) and sections 8.44-8.46 of the Code which prescribes the use of incentive mechanisms wherever the regulator considers its appropriate and where they are consistent with the provisions set out in section 8.

The Commission has used this approach to determine the debt margin in the recent GasNet, ElectraNet SA and SPI PowerNet Decisions. Nevertheless, EAPL and other parties have not had the opportunity to directly comment on this approach in the context of this assessment process. However, EAPL's response to the *Draft Decision* proposed that the debt margin should be based on 'capital market information' which is reflective of the market conditions for funds.[228] Moreover, other stakeholders have been aware of the Commission's position relating to the establishment of this parameter in electricity and gas decision documents released in 2002.

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228 EAPL response to the Draft Decision, 14 March 2002, p. 17.

Methodology

The benchmarking approach to establishing the debt margin requires the consideration of two distinct empirical questions: the appropriate benchmark credit rating of the service provider; and the market observed debt margin associated with the benchmark credit rating.

With regard to the benchmark credit rating of the service provider, the Commission considers that the relevant Code provisions (sections 8.30 and 8.2(e)) are best met by reference to Australian gas transmission companies. It is important for consistency with other parameter assumptions that these companies are stand alone entities and are devoid of government ownership. In addition, it is important that the gearing ratio of the entities used to calculate the debt margin are not significantly different from the gearing assumptions used to determine the WACC.[229]

The table below sets out the long term credit rating for four Australian transmission and distribution gas companies that meet the stand alone entity criteria and have been assigned a credit rating from ratings agency Standard and Poor's.[230] As indicated, the average gearing ratio (debt/(debt+equity)) of these companies is 62.1 per cent, which is just slightly higher than the 60 per cent benchmark rate proposed by EAPL.

Table 2.6.7.3: Credit rating associated with stand alone energy companies

Company	Long term rating	Gearing
AGL	A	52.2
Alinta Gas	BBB	49.2
Envestra	BBB	79.9
GasNet Australia	BBB	67.2
Average	**BBB+**	**62.1**

Source: Standard and Poor's, *Australia and New Zealand CreditStats 2003*, June 2003

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[229] All else being equal, the level of gearing effects the risk of lending to a company and thus may have an impact on the assigned credit rating.

[230] A stand-alone entity is defined as an entity that does not have a parent company (a company that holds the majority of voting stock). With regard to the companies used to estimate the benchmark credit rating:

- approximately 19 per cent of Envestra Ltd is owned by Cheng Kong Infrastructure Holdings (Malaysia) Ltd and another 19 per cent is owned by Origin Energy Ltd (source: http://www.envestra.com.au 04/08/03 data).
- 21 per cent of AlintaGas is owned by WA Gas Holdings Pty Ltd, which is jointly owned by Aquila Inc and United Energy Limited (source: http://www.alintagas.com.au).
- The largest shareholder of GasNet is National Nominees Ltd with 5.78 per cent of units (source: GasNet Annual Report 2002)
- The largest shareholder in AGL is JP Morgan Nominees Australia Limited with 9.58 per cent of issued shares (source: AGL concise Annual Report 2002).
- TXU Australia was not included in the benchmark as it is a wholly-owned subsidiary of TXU North America.

On the basis of this data, the Commission considers that a BBB+ credit rating represents an appropriate proxy credit rating for the benchmark company.[231]

Having established a proxy credit rating, a benchmark cost of debt can be determined. Asset owners raise debt either through bank markets or through the private/public capital markets. Debt requirements have primarily been met by the bank market for projects involving construction in Australia.[232] Evidence suggests that for energy infrastructure refinancing arrangements have also largely been met by institutional lenders, although capital markets have played a role (for example, the November 2000 and March 2002 debt issues by GasNet Australia and the 2002 Origin Energy debt issuance program).[233]

While bank debt has dominated energy infrastructure debt financing, the Commission considers that it is appropriate to use information from capital markets as the basis of the debt margin. This is information on the cost of debt in capital debt market is widely available and is therefore transparent to all interested parties. In contrast, information on the cost of debt charged by banks is not widely available in the public domain and is likely to vary between market observers and may be sensitive to specific bank-firm relationships. Consequently, the Commission is of the view that cost estimates obtained through reference to capital market data represent best estimates arrived at on a reasonable basis in accordance with section 8.2(e) of the Code.

Furthermore, the Commission notes that the use of capital market data is consistent with the approach used in the GasNet, SPI PowerNet and ElectraNet decisions and the methodology used by the ESC.[234] Finally, as noted previously, EAPL has itself proposed the use of capital market data to determine the debt margin.[235]

The Commonwealth Bank of Australia regularly publishes data on capital market debt margins through its CBA Spectrum service. Specifically, this service publishes information relating to the credit ratings AA through BBB for a variety of maturities. Given its transparency, the Commission considers that the use of this information is appropriate as the basis of the debt margin benchmark.

To remain consistent with the measurement of the risk free rate parameter, the debt margin has been calculated using the 40-day average of debt issued to BBB+ entities with maturity of five years. This measurement approach should limit any market aberrations that may arise. The 40-day average of the BBB+ debt margin over the

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[231] Some of these companies also have non-regulated elements, which all else being equal, should lower the overall credit rating of the entity. Therefore, the rating for a 100 per cent regulated benchmark company would generally be higher than the benchmark determined above.

[232] Macquarie Bank, *Issues for Debt and Equity Providers in Assessing Greenfields Gas Pipelines,* Report for the ACCC, May 2002. p. 7.

[233] Macquarie Bank, *Issues for Debt and Equity Providers in Assessing Greenfields Gas Pipelines,* Report for the ACCC, May 2002. p. 22.

[234] For example ESC, *Final Decision: Review of gas access arrangements*, October 2002, pp. 360-361.

[235] EAPL response to the Draft Decision, 14 March 2002, p. 17.

same period used to measure the risk free rate (that is, the period ending 17 September 2003) is 0.92 per cent or 92 basis points.[236]

Consequently, the Commission has adopted a debt margin of 92 basis points for this *Final Decision*. A debt margin of 92 basis points above the proposed nominal risk free rate of 5.3 per cent generates a nominal cost of debt of 6.2 per cent.[237]

The cost of debt

EAPL has proposed a pre-tax nominal cost of debt of 7.3 per cent derived using a risk free rate of 6.1 per cent and a debt margin of 1.20 per cent. In comparison, the parameters required by the Commission, as discussed above, result in a pre-tax nominal cost of debt of 6.2 per cent and a pre-tax real cost of debt of 3.9 per cent.

2.6.7.4 The return on equity

EAPL has elected to use the CAPM to estimate the required return on equity. The CAPM specifies the return required by equity holders given the opportunity cost of investing in the market (r_f), the market's own volatility ($E(r_m)$-r_f), and the relative systematic risk of holding equity in a particular entity (β_e). The CAPM formula may be expressed as:

$$r_e = r_f + \beta_e (E(r_m) - r_f)$$

According to the CAPM, the relevant risk that equity holders should be rewarded for bearing is systematic risk (also known as non-diversifiable risk or market risk). That is the risk that is applicable to the overall market, such as risks arising from exposure to changes in the level of economic activity, interest rates and inflation rates.

The distinction between systematic and non-systematic (also known as specific or diversifiable risk) is a fundamental tenet of the CAPM which assumes that investors are able to eliminate the impact of specific risks (such as asset stranding, the risk of reduced revenues as a result of increased competition and operations risk) on any one asset by holding a well balanced and diversified portfolio of assets. This assumption is reflected in both the market risk premium and the equity beta. The market risk premium is essentially the measure of reward for holding a well diversified portfolio of risky assets relative to holding a risk free asset. Similarly, the equity beta is a measure of the relative systematic risk of an individual entity's equity.

The Commission regards the CAPM as being the appropriate framework for determining the required return on equity and notes that its use is consistent with the example contained in section 8.31 of the Code. The Commission is also cognisant of

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236 This calculation is based on an average corporate bond yield of 6.20 per cent and an interpolated government bond rate of 5.28 per cent. The interpolated government bond yield differs slightly from the risk-free rate calculated over the same period given the adoption of a global interpolation by CBA Spectrum, as opposed to the local linear interpolation used by the Commission. It was considered appropriate for consistency purposes to use the CBA Spectrum corporate bond data to measure bond spreads.

237 The Commission added a premium to the debt margin for debt raising costs in ACCC, *Final Decision: GasNet*. EAPL has not sought the explicit inclusion of debt raising costs in its building block claims (EAPL response to the Commission, 10 June 2003, pp. 7-8).

the need to ensure the integrity of the CAPM is maintained by limiting the compensation available to equity holders to systematic risk. Failure to do so would clearly be inconsistent with the CAPM and may lead to significant bias.[238]

Specific risks may still be recognised in the regulatory framework. However, the Commission prefers that where these risks can be identified and quantified that the net impact on earnings be accounted for in a transparent manner through the projected cash flows.[239] Generally, there only needs to be compensation in cash flows for specific risk when the risks can be assessed as being asymmetric, that is they impact positively or negatively on the return expected from business operations. The Commission notes that specific risks may also be mitigated by: faster than normal rate of regulatory depreciation to provide a more timely return of return of capital for assets at risk of bypass;[240] economic depreciation;[241] and a longer regulatory period.[242]

As indicated by the formula above, there are three principal determinants of the required return on equity that is, the risk free rate (r_f), the market risk premium ($E(r_m)-r_f$) and the relative systematic risk of the individual entity's equity (β_e). The following discussion focuses on the appropriate market risk premium and the equity beta.

Market risk premium

As one of three principal determinants of the expected return on equity, the market risk premium represents the additional return investors expect to earn for investing in a well diversified portfolio of risky assets relative to investing in risk free instruments (defined as $E(r_m)-r_f$ where $E(r_m)$ represents the expected value of the return on the overall market). Theoretically the market risk premium is an ex ante premium, however, for practical purposes historic data has typically been used as a proxy measure.[243]

The *Draft Decision* observed that the market risk premium appeared to be declining and that a more appropriate value may be 5.5 per cent. The Commission did, however, note that the downward trend was not fully accepted by market participants and commentators and on this basis decided to adopt a market risk premium of 6 per cent.

Since the release of the *Draft Decision*, Lally has assessed various approaches and estimates of the market risk premium on behalf of the Commission. The findings of this assessment were set out in a report to the Commission entitled *The cost of capital under dividend imputation*. Briefly, Lally determined that across four different approaches the average estimate for the market risk premium in Australia was 6.1 per cent and concluded that:

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[238] K. Davis, & J. Handley, *Report on Cost of Capital for Greenfields Investment in Pipelines*, March 2002, p. 21.

[239] ACCC, *DRP*, May 1999, p. 72.

[240] ACCC, *Post-Tax Revenue Handbook*, October 2001, p. 9. and ACCC, *DRP*, May 1999, section 5.3

[241] ACCC, *Final Decision: CWP*, pp. 51-54.

[242] ACCC, *DRP*, May 1999, section 4.7 and ACCC, *Final Decision: ABDP*, p. 156.

[243] ACCC, *DRP*, May 1999, p. 78.

> ...the range of methodologies examined give rise to a wide range of possible estimates for the market risk premium and these estimates embrace the current value of 6 per cent Accordingly the continued use of the 6 per cent estimate is recommended.[244]

Similarly, the issue of the appropriate methodology and value to be accorded to the market risk premium has been the subject of a detailed examination by the ESC. Giving consideration to a number of studies and estimations of the magnitude of the market risk premium, the ESC concluded that the weight of evidence before it provided:

> a sound basis for adopting an estimate of the equity premium that is below the point estimate provided by the average of the historical premia, but which otherwise is within the range provided by historical returns, given the variability associated with this measure.[245]

Accordingly, the ESC concluded that a value of 6 per cent was appropriate for regulatory purposes. However, it did acknowledge that some players in the market would adopt a market risk premium below the 6 per cent previously adopted by the ESC.

The Commission concurs with both Lally and the ESC that there is no clear consensus on the methodology to utilise when deriving the market risk premium and in turn the appropriate value to accord to the parameter. Moreover, the Commission recognises, as the ESC did, that there is evidence from recent studies which would appear to suggest that the market risk premium is less than the 6 per cent used to date in regulatory decisions.

The Commission has reviewed the Pareto report's comparison between the market risk premium adopted by Australian (6 - 6.5 per cent) and UK regulators (3 - 4 per cent).[246] However, in the absence of any adjustment for differences in financial market conditions and institutional arrangements between countries the Commission hesitates to draw any firm conclusion from this information.

Notwithstanding the uncertainty surrounding the derivation of the market risk premium, a point estimate is required to derive the post-tax nominal return on equity. In view of the information currently before it, the Commission considers that EAPL's proposed market risk premium of 6 per cent is not inconsistent with section 8.2(e) and in turn will provide for a rate of return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service (section 8.30 of the Code).

Equity beta

Another fundamental determinant of the expected return on equity is the equity beta which measures the sensitivity (or degree of co-movement) between the return from a particular equity investment and the return from the market portfolio (usually

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244 M. Lally, *The cost of capital under dividend imputation,* June 2002, p. 43.

245 ESC*, Final Decision: Review of gas access arrangements*, October 2002, p. 336.

246 Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, p. 27.

represented by the stock market). An equity beta greater than one is indicative of an entity that has returns which are expected to be more sensitive to systematic influences than the market average (which by definition has an equity beta of one). Conversely an equity beta less than one is indicative of an entity that has returns which are expected to be less sensitive than the market average.

For listed entities the estimation of an ex post equity beta is relatively simple requiring only a sufficiently long time series of returns to the entity and the market portfolio to estimate the expected volatility of the entity relative to the overall market. Formally, this is given by:

$$\beta_e = \frac{Cov(r_e, r_m)}{Var(r_m)}$$

However, estimating the equity beta for the regulated activities of an entity is more complex than the empirical approach outlined above. These complexities stem from the fact that:

- many regulated entities are not listed on the stock exchange;
- where a regulated entity is listed, it may not have been listed on the stock exchange for a sufficient amount of time to generate robust data for beta estimation; and
- it is unlikely that a listed entity will exclusively provide the regulated service, resulting in the estimated equity beta not accurately reflecting the systematic risk of the regulated activities.

As a consequence, the equity beta relevant to the regulated activities of an entity must be estimated. A common method to estimate a proxy beta is to have recourse to a group of listed entities which are considered to be operating in a similar business and facing similar levels of systematic risk as the regulated entity. However, given the effect gearing has on the equity beta an alternative measure which removes the effects of gearing (de-levering) is required. That alternative measure is the asset beta ($ß_a$) which is the equity beta that would apply if the firm was wholly financed by equity.

The asset beta may then be converted to an equity beta using a consistent gearing assumption. The elimination of the gearing effect then enables comparisons to be made across entities (or with the same entity over time) either on an asset beta basis or on a re-levered equity beta basis.

While there are a number of de-levering and re-levering formulae available, the Commission has typically adopted the Monkhouse formula. This formula recognises the impact of imputation credits. It is also consistent with the CAPM assumptions. That is, it is derived on the basis that the firm has an active debt management policy which maintains gearing at a constant level. The Monkhouse formula can be written as:

$$\beta_e = \beta_a + (\beta_a - \beta_d)[1 - (\frac{r_d}{1 + r_d})(1 - \gamma)T_e]\frac{D}{E}$$

This formula may be used to de-lever from an equity beta with a specific gearing ratio to yield the relevant asset beta. It may then be used to re-lever to an equity beta with a standard gearing ratio. The process of de-levering and re-levering also requires an assumption regarding the value for the debt beta ($ß_d$) which measures the level of systematic risk borne by debt holders. If an equity beta is de-levered to derive the relevant asset beta and then re-levered it to derive a benchmark equity beta, then provided the same debt beta assumption is used, the actual value assumed for the debt beta will have only a minor effect on the re-levered equity beta.

EAPL's contentions

At the time the *Draft Decision* was released the availability of empirical data for comparably listed entities was limited. In the absence of this empirical data the Commission concluded that a proxy asset and debt beta of 0.50 and 0.06, respectively were appropriate. These two parameters combined to yield an equity beta of 1.16. EAPL has adopted the same approach of using a proxy asset and debt beta for the revised access arrangement and adopted an asset beta of 0.62 and a debt beta of 0.06. Combined these two parameters result in an equity beta of 1.45 which EAPL has contended reflects the MSP's exposure to:

- Increased competition from the EGP;
- Increased risk from the development of coal seam methane in NSW which would bypass the MSP. EAPL added that the recent market initiatives of Sydney Gas demonstrated that coal seam methane represents a genuine alternative source of gas for the Sydney market over gas sourced via the MSP;
- Increased competition from alternative energy sources; and
- Uncertainties with deliverability from Moomba and the development of alternative gas sources. EAPL noted that this uncertainty exposed it to additional systematic as well as non-systematic risk.

As set out previously, the Commission recognises that consistency with CAPM framework requires that equity holders only be compensated for systematic risk and that where specific risks can be identified and quantified the net impact on earnings should be factored into projected cash flows. With reference to this approach the Commission has examined each of the claims made by EAPL in its revised access arrangement regarding the risks it faces. The sources of risk claimed by EAPL can broadly be categorised as competition faced from other market participants and alternative energy sources, and the potential for partial stranding.

With regard to the first two contentions, EAPL has claimed that it is exposed to a higher level of systematic risk resulting from increased competition from other market participants. The Commission does not consider that this risk is systematic in nature. Rather, the Commission considers that this is a specific risk that should be reflected in the demand forecasts and not the equity beta. The Commission notes that within the throughput forecasts submitted by EAPL allowance has been made for the market share it expects both Sydney Gas Company and the EGP to capture. The Commission considers this to be the appropriate method to account for these specific risks and accordingly rejects EAPL's contention that this factor should give rise to a higher equity beta.

Similarly, the Commission considers that competition from alternative energy sources (which the Commission has interpreted as competition from electricity and other forms of energy rather than other sources of gas) is a risk that is specific to the MSP and accordingly should not be compensated through a higher equity beta. Again, the Commission considers that this factor would implicitly be taken into account when deriving throughput forecasts.

Another factor which EAPL claim exposes it to additional systematic risk is the uncertainty surrounding deliverability from Moomba and the development of alternative gas sources. EAPL has acknowledged that some aspects of this claim may be viewed as non-systematic in nature. It would appear in making this claim that EAPL is alluding to the potential risk of partial stranding of the MSP. That is, if reserves in the Cooper Basin fall or if Moomba does not become the supply hub for northern gas (from Papua New Guinea or Timor Sea) then there is a risk that southern sources of gas will result in the MSP largely being bypassed. The issue of stranding risk was considered by the Commission in the MAPS Final Approval. The Commission noted in that instance that Epic had not provided any evidence to suggest that the stranding risk facing the MAPS was in any way related to the movements in the overall market. Accordingly, the Commission concluded that this was a unique, non-systematic risk which should be addressed by other means.[247]

A similar conclusion can be reached in this instance. That is, while EAPL has claimed that this is a source of both systematic and non-systematic risk it has presented no evidence to suggest that the uncertainty surrounding deliverability from Moomba affects the degree of co-variation between the returns generated by the MSP and returns on the overall market. Consequently, this issue is not relevant to the determination of the equity beta.[248] As stated in the MAPS Final Approval, the Commission considers that the risk of partial stranding is a unique risk which should be accommodated either in volume forecasts or in the depreciation profile adopted for the pipeline.

EAPL has also contended that the MSP differs from MAPS because it is not fully contracted and differs from the Victorian gas transmission assets because the NSW market is not as deep or large as the Victorian market. The Commission does not regard either of these two factors as supporting the contention that the MSP faces a higher level of systematic risk than that faced by either the Victorian gas transmission assets or the MAPS. That is, size of the market or the level of contracted capacity does not in itself imply a greater degree of systematic risk and a higher equity beta.

Having examined the arguments presented by EAPL the Commission does not consider that the 1.45 equity beta value proposed is an appropriate measure of the systematic risk faced by the MSP over the initial access arrangement period. Rather, the Commission considers that the value proposed by EAPL overstates the level of systematic risk faced by the MSP. An equity beta of 1.45 would generate a return in excess of that which is commensurate with prevailing conditions in the market for funds given the risk involved in delivering the reference service as required by section 8.30 of the Code.

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[247] ACCC, *Final Approval: MAPS,* 31 July 2002, p. 17.

[248] K. Davis, *Report on Asset and Debt Beta for MAPS*, 20 August 2001, p. 2.

Empirical estimates

In the period since the release of the *Draft Decision*, a longer time series of equity beta estimates for APT and other comparably listed energy utilities has become available. The availability of this empirical data led the Commission to engage the ACG to undertake a review of the available empirical evidence on equity betas for regulated gas transmission companies. This review was completed in July 2002. Additional market data has since become available, allowing the estimates to be updated.

Using March 2002 data from the Australian Graduate School of Management Risk Measurement Service (AGSM) and assuming a 60 per cent gearing ratio, a debt beta of 0 and 0.15, and excluding and including tax from the re-levering formula, the ACG made the following observations using a sample of comparable Australian entities (these were AGL, APT, Envestra and United Energy):

- Estimates of the simple average equity beta lay in the range 0.66 - 0.69 with individual equity betas ranging from 0.4 - 1.04. The individual equity beta estimate for Envestra lay at the lower end of the range while the estimate for APT resided at the upper end. With regard to the APT estimates the ACG noted that they were based on less than the desired number of data points required for a statistically reliable estimate; and
- Estimates of the average asset beta lay in the range 0.27 - 0.37[249] with individual asset betas ranging from 0.16 - 0.53.[250] The individual asset beta estimate for Envestra lay at the lower end of the range while the estimate for APT resided at the upper end.

The ACG also considered data for comparable entities in the US, Canada and UK. These data produced lower beta estimates and the ACG concluded that this secondary information supported the view that Australian estimates were not understated. The ACG observed that:

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North American or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[251]

The ACG submitted that reliance by the Commission upon the most recent market evidence on beta in its regulatory decisions would go some way towards reducing the uncertainty associated with the regulatory process in estimating beta.[252] However, the

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[249] ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities, Final Report*, July 2002, p. 40.

[250] ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities, Final Report*, July 2002, Appendix B p. 2.

[251] ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities, Final Report,* July 2002, p. 42.

[252] ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities, Final Report,* July 2002, p. 41.

ACG cautioned against exclusive reliance upon market evidence at present given the limited sample size and the length of the time series relied upon for APT and United Energy. The ACG noted that in the future, it should be possible for greater reliance to be placed upon market evidence but in the interim a conservative approach to beta estimation should be retained by Australian regulators (that is, a proxy beta of approximately one). The ACG concluded that:

> This report has demonstrated that no implication can be drawn from current market evidence that the proxy betas that Australian regulators have adopted are likely to understate the 'true' beta – rather, as noted above, the current evidence suggests regulators systematically have erred in favour of the regulated entities.[253]

Subsequent to the release of the ACG report further estimates of equity betas have been released by the AGSM. The Commission has used this information to examine whether the conclusions reached in the ACG report still hold with the longer time series of data for APT and United Energy (see Table 2.6.7.4).

Assuming a 60 per cent gearing ratio and debt beta of 0 and 0.15, the re-levered equity betas to June 2003 ranged from -0.04 – 0.35 with United Energy and AGL at the lower end of this range and APT at the upper end. On a simple average basis (as adopted by the ACG) the latest data would imply a proxy equity beta of approximately 0.12. The Commission has also derived a weighted average estimate of the proxy beta which suggests a proxy equity beta in the range 0.20 – 0.23.[254]

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[253] ACG, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities, Final Report,* July 2002, p. 43.

[254] The weights are based on the inverse of the variance associated with individual estimates so more statistically reliable estimates receive a greater weight. This approach is based on Swamy, P.A.V.B, Efficient Inference in a Random Coefficient Regression Model, 1970, *Econometrica,* which shows that such a weighted average provides a statistically more efficient estimate.

Table 2.6.7.4: Equity beta estimates from June 2003 AGSM Data

	AGSM data			Re-levered equity beta (60% gearing)[(b)]	
Listed Company	Equity Beta estimate β_e	Standard error of equity beta	Gearing ratio (D/V)	$\beta_d = 0$	$\beta_d = 0.15$
AGL	-0.01	0.30	0.52	-0.01	-0.04
APT[(c)]	0.39	0.24	0.66	0.33	0.35
Envestra	0.39	0.26	0.80	0.20	0.27
United Energy	-0.03	0.48	0.42	-0.04	-0.11
Simple average	*0.19*	*0.32*	*0.60*	*0.12*	*0.12*
Standard error of simple average[(d)]					*0.21*
Weighted average[(a)]				**0.20**	**0.23**
Standard error of weighted average[(d)]					**0.17**

Source: Equity beta estimates - AGSM, Risk Measurement Service, June 2003
Gearing levels - Standard & Poor's Australia & New Zealand CreditStats 2003, June 2003, pp. 31-32

Notes:

(a) the weighted average takes account of the precision of each estimate and is a statistically superior estimate of the pooled equity beta proxy[255]

(b) firm equity betas were de-levered and re-levered using the Monkhouse formula assuming γ=0.5, T_e=0.10, r_d=0.7

(c) Estimates for AGL, Envestra and United Energy are based on the AGSM's June 2003 data and preferred 48 observations. The estimate for APT is based on 36 observations

(d) The standard error of the simple average and weighted averages allow the confidence intervals for the pooled estimates to be calculated

This latest data supports the ACG's conclusion that the proxy equity betas adopted by Australian regulators to date are likely to understate the market based measurement. This suggests regulators have systematically erred in favour of the regulated entities.[256]

The Commission has also examined the AGSM data for the periods to September 2002 to March 2003. The results produced similar conclusions as indicated by Table 2.6.7.5.

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[255] Swamy, P.A.V.B, 'Efficient inference in a random coefficient regression model', 1970, *Econometrica,* pp. 311-323, and Maddala, G. S., *Econometrics*, 1977, McGraw Hill Inc, pp. 400-403.

[256] ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC,* July 2002, p. 43.

Table 2.6.7.5: Equity beta estimates September 2002 to March 2003

	AGSM data			Re-levered equity beta (60% gearing)	
	Equity Beta estimate β_e	Standard error of equity beta	Gearing ratio (D/V)	$\beta_d = 0$	$\beta_d = 0.15$
September 2002					
AGL	0.09	0.31	0.52	0.11	0.08
APT	0.25	0.27	0.66	0.21	0.24
Envestra	0.31	0.27	0.80	0.16	0.23
United Energy	0.18	0.47	0.42	0.26	0.19
Simple average	*0.21*	*0.33*	*0.60*	*0.18*	*0.18*
Standard error of simple average					*0.20*
Weighted average				**0.17**	**0.22**
Standard error of weighted average					**0.12**
December 2002					
AGL	0.08	0.32	0.52	0.10	0.07
APT	0.24	0.27	0.66	0.20	0.23
Envestra	0.33	0.28	0.80	0.17	0.24
United Energy	0.25	0.48	0.42	0.36	0.30
Simple Average	*0.23*	*0.34*	*0.60*	*0.21*	*0.21*
Standard error of simple average					*0.21*
Weighted Average				**0.18**	**0.22**
Standard error of weighted average					**0.13**
March 2003					
AGL	0.06	0.30	0.52	0.07	0.04
APT[(a)]	0.77	0.61	0.66	0.66	0.68
Envestra	0.34	0.24	0.80	0.17	0.25
United Energy	0.08	0.45	0.42	0.12	0.05
Simple Average	*0.31*	*0.40*	*0.60*	*0.25*	*0.25*
Standard error of simple average					*0.23*
Weighted Average				**0.21**	**0.24**
Standard error of weighted average					**0.21**

Source: AGSM, Risk Measurement Service, September 2002, December 2002 and March 2003

Notes: (a) The test statistic for thin trading provided by the AGSM indicated that thin trading was likely to be a concern for APT. In this instance the 'thin-trading' (Scholes-Williams) estimate was used.

Examining the results set out in Table 2.6.7.5 indicates:

- in September 2002, the weighted average proxy beta was 0.17 – 0.22 with APT's re-levered equity beta estimate lying in the range 0.21 – 0.24;
- in December 2002, the weighted average proxy beta was 0.18 – 0.22 with APT's re-levered equity beta estimate lying in the range 0.20 – 0.23; and

- in March 2003, the weighted average proxy beta was 0.21 – 0.24 with APT's re-levered equity beta estimate lying in the range 0.66 – 0.68. The test statistic for thin trading provided by the AGSM indicated that thin trading was likely to be a concern for APT. In this instance the Scholes-Williams estimate was used rather than the ordinary least squares estimate of 0.29 – 0.31.

The results of this empirical analysis demonstrate that EAPL's proposed equity beta of 1.45 lies well beyond the range of 0.66 – 0.69 originally estimated by the ACG and exceeds the most recent empirical estimates which range from 0.20 – 0.23. However, the results also demonstrate some degree of volatility and indicate that thin trading can have a significant impact on the analysis. This is illustrated by the March 2003 estimates for APT being significantly higher than earlier estimates. This was a similar concern when ACG carried out its analysis. In view of the volatility, the impact of thin trading and the number of observations, the Commission has decided that some caution should be exercised in relying exclusively upon empirical data at this time.

Nevertheless, the Commission still views the latest empirical evidence as relevant in assisting it in its assessment of the equity beta proposed. Furthermore, the Commission notes that section 8.30 of the Code states that the rate of return used to determine a reference tariff should provide a return which is commensurate with the prevailing conditions in the market for funds and the risk involved in delivering the reference service. The Commission therefore considers that having regard to empirical research and evidence is consistent with section 8.30. Finally, the Commission notes that reference to empirical data will form a reasonable basis upon which beta estimates can be made and satisfies the criteria of section 8.2(e) of the Code.

EAPL engaged NECG to respond on its behalf to the ACG report. The criticisms raised by the NECG can be broadly summarised as: the potential volatility of beta estimates over time; the weight which should be given to the proxy estimate over the actual estimate for the regulated entity; the use of an imperfectly comparable sample of firms; the inclusion of Envestra within the sample; and the limited inference which can be drawn from the international comparisons presented.

In relation to the first issue, the Commission acknowledges that there is the potential for beta estimates to be volatile over time and notes that this would be a concern if the Commission relied upon a point estimate for a particular company. However, the Commission's objective in assessing the relevant equity beta is not to identify a point estimate for a particular company but rather, its focus is upon identifying a beta which is commensurate with the systematic risks faced by a benchmark company providing the types of service offered by the regulated entity. The use of benchmarks is contrary to the position postulated by the NECG who have argued that greater weight should be placed upon the actual estimate for an entity rather than the benchmark sample. However, as discussed earlier in this section, the Commission considers that the use of benchmarking is appropriate when establishing a rate of return under section 8.30 of the Code.

In relation to the second issue, if the Commission were to refer to the individual service provider's equity beta estimates then it is clear from the analysis set out previously that this would result in an equity beta well below the range proposed by EAPL. According to the June 2003 AGSM data, APT's equity beta (re-levered with a 60 per cent gearing ratio and assuming a debt beta of 0 or 0.15) lay within the range of 0.33 – 0.35, substantially below the 1.45 proposed by EAPL. Data for September 2002 and December 2002 data (which don't suffer the data shortfall associated with the March 2003 data) demonstrate that for a sequence of beta estimates covering different data period there has been a consolidation of beta estimates at a level well below the range contemplated by EAPL.

In relation to the third issue, the Commission notes the ACG's view on the comparability of firms within the sample. That is, entities who undertake significant non-regulated activities (such as AGL and United Energy) would be expected to have a higher systematic risk and as a result the inclusion of these entities within the average is likely to overstate the proxy beta for a purely regulated entity.[257]

On the issue of whether Envestra should be excluded from the sample because it has an unusual gearing and presents a significant risk of bias.[258] The Commission also refers to the reasons set out by the ACG in concluding that there is no reason to believe that Envestra's 'unusual' gearing is likely to lead to biased beta estimates.[259] Moreover, the Commission notes that beta estimates for APT and Envestra based on a longer time series will improve the statistical reliability of the estimates used.

Finally, with regard to NECG's comments on the use of international beta estimates. The Commission considers that international estimates may be useful but is aware that caution must be exercised in interpreting these estimates given the number of assumptions and adjustments required for differences in financial markets and institutional arrangements between countries. The Commission is also aware that a comparison of equity betas across countries requires an implicit assumption that the systematic risk characteristics observed in one country are similar to those that would be observed in another.[260] As alluded to by the ESC, the assumption that the systematic risk characteristics are similar across countries may be affected by a number of factors including the composition of the overall market, differences in taxation and gearing.[261] Accordingly, while the Commission does not discount such information, the regard it has to these estimates will be secondary in comparison to estimates derived from the Australian market.

This point was also made by the ACG who submitted that the sensitivity of asset prices in any market:

> …will depend upon a number of matters, such as institutional factors and government policies. Accordingly, it is considered that these estimates should remain a secondary

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257 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC*, July 2002, p. 55.

258 NECG, *Response to ACG Report on Proxy Beta Estimates*, 4 November 2002, p. 6.

259 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC*, July 2002, pp. 48-50.

260 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities, Final report for the ACCC,* July 2002, p. 47.

261 ESC, *Draft Decision: Review of gas access arrangements*, July 2002, p 229.

> source of information, with primary regard to be had to evidence from the Australian market.[262]

The ACG also noted that the assumptions required for equity beta estimates for international entities were not so restrictive to render the information irrelevant.[263]

It is against this backdrop that the Commission has examined the Pareto report's contention that Australian regulators have adopted higher and more varied values of equity beta than various UK regulators. Initially, the conclusion that Australian regulators have adopted higher equity betas than regulators in other countries appears to be correct. However, the Commission notes that caution must be exercised in drawing inferences from international data when no allowance is made for differences in financial market conditions and institutional arrangements between countries. As noted by the ACG, there are a number of factors which may affect the strength of the relationship between the returns of a regulated entity and the overall market across different countries.[264] For example, differences in the composition of the overall market across countries may affect the covariance of the return of any asset to the market as a whole. In addition, the sensitivity of the returns of a regulated gas transmission entity to systematic risk may differ across countries due to differences in government policies, taxation regimes and average gearing levels.

The Pareto report also commented on the level of access the UK regulator has to financial data for listed water companies, which according to the report 'greatly improves the clarity of data with which the regulators are able to inform their judgement on these matters'.[265] The Commission agrees that access to such information improves the decision making process and it is for these reasons that the Commission is beginning to place greater weight on the available empirical data with respect to beta estimation.

Conclusion

The Commission has concluded from the above analysis that EAPL's proposed equity beta of 1.45 overstates the degree of systematic risk it is exposed to. The Commission notes that an equity beta greater than one would indicate an expectation that EAPL is exposed to a greater level of systematic risk than the market in general. Current empirical estimates of the re-levered equity beta which suggest that the equity beta should be considerably less than one.[266] This indicates that an equity beta of 1.45 would result in a rate of return which fails to reflect the prevailing conditions in the market for funds and the risks involved in delivering the service (section 8.30).

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262 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC*, July 2002, p. 58.

263 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC,* July 2002, p. 47.

264 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, *Final report for the ACCC,* July 2002, p. 19.

265 Pareto, *The Weighted Average Cost of Capital for Gas Transmission Services – Benchmarking Regulated Australian and UK "Vanilla" WACC Components,* July 2002, p. 25.

266 The June 2003 AGSM data suggest a weighted average proxy equity beta of 0.20 - 0.23.

While empirical estimates of equity betas for a small number of comparable firms is now available, the Commission considers that in view of the problems associated with thin trading and the limited number of observations for APT it may be premature to rely wholly on these estimates at this time. Consequently, and in reference to the ACG's conclusions and recent regulatory decisions (including those made by the Commission[267] and the ESC[268]), the Commission considers that an equity beta of one is appropriate for the MSP at this time.

The Commission recognises that given the market evidence currently available this may be viewed as a conservative position which confers some benefit upon EAPL. However, the Commission considers that until more observations become available and the equity beta estimates become more statistically reliable, it is appropriate to adopt this conservative approach. This reflects the Commission's view that it is better to err on the side which ensures that there are sufficient investment incentives. To take a contrary position would risk deterring investment in the pipeline (section 8.1(d)) and jeopardise other aspects of the service such as the safe and reliable operation of the pipeline (section 8.1(c)).

After taking into account the objectives of sections 8.1 and 2.24, the Commission considers that on balance an equity beta of one will result in a rate of return permitted by section 8.30 of the Code. The Commission notes, however, that in future considerations as more market observations become available and the estimates become more statistically reliable then it would envisage placing more weight on the latest empirical estimates (consistent with 8.30) than it has in the this *Final Decision*.

Finally, the Commission has examined the contention contained in the Pareto report that too much caution or conservatism is not in the interests of end users. However, the Commission considers that where there is some uncertainty regarding the value of a parameter, and this gives rise to a conflict in objectives in section 8.1, then it must have regard to the potential for the value adopted to affect the overall performance of the service provider.

The return on equity

As mentioned above, the rate of return critical to the regulatory framework applied by the Commission to a regulated business is the expected post-tax nominal return on equity (r_e). This return determines whether investors will be willing to provide equity to finance the infrastructure.

EAPL has proposed a post-tax nominal return on equity of 14.8 per cent derived using the CAPM formula and a risk free rate of 6.13 per cent, a market risk premium of 6 per cent and an equity beta of 1.45. In comparison, the parameters proposed by the Commission, as outlined above, result in a post-tax nominal return on equity of 11.3 per cent. Although the Commission recognises that it has provided EAPL with the benefit of any uncertainty surrounding the value of the equity beta, it considers that on balance an 11.3 per cent return on equity will result in a rate of return consistent with

[267] ACCC, *Final Decision: GasNet*, p. 11, and ACCC, *Final Decision: ABDP*, p. 93.

[268] ESC, *Final Decision: Review of gas access arrangements*, October 2002, p. 138.

section 8.30 of the Code. It is important to note that the 11.3 per cent post-tax nominal return on equity is an expected return. Accordingly, scope exists for EAPL to earn a rate of return in excess of this within the regulatory framework.

2.6.7.5 Estimation of the WACC

EAPL has proposed a pre-tax real WACC of 7.9 per cent, which was derived using a post-tax return on equity of 14.8 per cent, a pre-tax nominal cost of debt of 7.3 per cent and an assumed effective tax rate of 30 per cent. For the reasons set out above, the Commission considers EAPL's proposal is likely to lead to a rate of return in excess of that contemplated by section 8.30.

The Commission notes that the financial market related parameters relied upon by EAPL has not been updated by EAPL since the submission of its revised access arrangement in May 2002. In contrast, the cash flow modelling undertaken by the Commission for the MSP is based on the latest available financial market data and assumes a CAPM generated post-tax nominal return on equity of 11.3 per cent, which when combined with a pre-tax nominal cost of debt of 6.2 per cent and a 60 per cent gearing ratio gives rise to a nominal vanilla WACC of 8.2 per cent. The cash flow analysis undertaken by the Commission indicates that a nominal vanilla WACC of 8.2 per cent is consistent with a post-tax nominal WACC of 7.53 per cent, and a pre-tax real WACC of 6.56 per cent.[269] A comparison of the WACC parameters and the WACC estimates can be found in Table 2.6.7.7.

The Commission acknowledges that the pre-tax real rate of return of 6.56 per cent is higher than the 5 per cent pre-tax real rate of return suggested by the EUAA, however, it is below the 7 per cent referred to by the EMRF. The Commission accepts that there will always be conflicting views on the appropriate rate of return for a service provider, however, these conflicts must be resolved within the framework provided by the Code.

To provide further perspective on the rate of return estimated, the Commission has undertaken a review of other regulatory decisions, as suggested by the EMRF, and the average return on the Australian stock market, as suggested by the PIAC.

In carrying out this review, the Commission is cognisant of the difficulties in comparing its regulatory decisions with the overall stock market. Similarly, the Commission is aware of the caution that must be exercised before drawing any inferences from regulatory decisions in other jurisdictions. Nevertheless, the Commission notes that based on the information contained in Table 2.6.7.6, the rate of return considered to be appropriate for the MSP is not unreasonable when compared to other recent Australian gas regulatory decisions.

[269] Cash flow analysis was carried out separately for both the mainline and regional segments. Different effective tax rates applicable to the segments, however, results in slight differences in the post tax rates. The rates cited in the body of the text are for the mainline. On the regional segments the post-tax nominal WACC is 7.0% and the pre-tax real WACC is 6.31%.

Table 2.6.7.6: Comparison of returns

	Date	Return on equity (%)	Vanilla WACC (%)
ACCC Final Decision for MAPS	Sep 2001	12.6	9.1
ACCC Final Decision for GasNet	Nov 2002	11.2	6.3
ACCC Final Decision for ABDP	Dec 2002	11.7	8.9
ACCC Final Decision for MSP	**Sep 2003**	**11.3**	**8.2**
ESC Final Decision for gas distribution	Oct 2002	11.8	6.8
OffGAR: Final Decision for DBNGP	May 2003	12.5	8.9[(a)]
Ofgem: Independent gas transmission	2002	8.3	5.5
Ofgem: Transco	2001	8.8	5.1
		5 year average return on equity	**10 year average return on equity**
All Ords Accumulation Index	Aug 2003	6.7	10.7

Source: ACCC, various decisions; ESC, *Final Decision: gas access arrangements*, October 2002; Pareto Associates, *The weighted average cost of capital for gas transmission services*, p. 24.
Notes: (a) Estimated by the Commission

As to the apparent 'deviation' between the rates of returns accorded by Australian and UK regulators, the Commission notes that these differences are not in themselves indicative of excessive returns as contended in the Pareto report. Rather, allowance must be made for differences in financial markets and institutional arrangements across countries. The differences in returns may also be a function of the relative maturities of the regulatory regimes. It is for these reasons that the Commission views international benchmarks as a secondary source of information. With regard to the stock market comparison, the Commission notes that the MSP return on equity is higher than the five year average share market return but lower than the 10 year average referred to by the PIAC.

Overall, the Commission considers that based on the information currently before it a nominal vanilla WACC of 8.2 per cent represents a rate of return which is commensurate with prevailing conditions in the market for funds given the risks involved in delivering the reference service (section 8.30). The Commission acknowledges that in reaching this conclusion it has tended to adopt a conservative approach to selecting parameters around which there is still some uncertainty (such as the value of the equity beta and gamma).

In these cases the Commission has found it difficult to determine a particular point estimate which could be termed the best estimate arrived at on a reasonable basis (as required by section 8.2(e)) and results in the closest alignment with the objectives set out in section 8.1 of the Code. In these instances the Commission has had recourse to section 2.24 of the Code and sought to balance EAPL's legitimate business interests and investment in the pipeline (section 2.24(a)) with the interests of users and prospective users (section 2.24(f)) and the public interest (section 2.24(e)) while also taking into account the effect on the economically efficient operation of the pipeline (section 2.24(d)) and the safe and reliable operation of the pipeline (section 2.24(c)). Overall, the Commission considers that where there is uncertainty surrounding a particular parameter, then a conservative approach which errs on the side which benefits the service provider is the most prudent approach. This approach will ensure that there are sufficient incentives for appropriate investment (section 2.24(a)) and that other aspects of the service, such as the safe and reliable operation of the pipeline (section 2.24(c)) will continue.

The Commission considers that the rate of return will: result in reference tariffs that are efficient in both level and structure (section 8.1(d)); provide EAPL with the opportunity to earn a stream of revenue which recovers efficient costs (section 8.1(a)); circumvent any potential distortion in investment in the pipeline and in upstream and downstream markets (section 8.1(d)); and replicate the outcome of a competitive market (section 8.1(b)). In addition a rate of return which can be termed commensurate with the prevailing market conditions and the risk involved will ensure the safe and reliable operation of the pipeline (section 8.1(c)). Finally, the Commission considers that the use of benchmarking will operate to provide EAPL with an incentive to reduce costs and to develop the market for services (section 8.1(f)).

As a result of the analysis discussed above, the Commission requires EAPL to amend its access arrangement in relation to the rate of return for the MSP. This is set out below.

Amendment FDA 8

In order for EAPL's access arrangement for the MSP to be approved the WACC estimates and associated parameters forming part of the access arrangement and access arrangement information must be amended to reflect the current financial market settings by adopting the parameters set out by the Commission in Table 2.6.7.7 of this *Final Decision*. The calculation of total revenue must reflect these parameters.

Table 2.6.7.7: Comparison of WACC parameters and estimates

Parameter		EAPL original proposal May 99	ACCC Draft Decision Dec 00	EAPL revised proposal May 02	ACCC Final Decision 15 Sep 03
General parameters					
Real risk free rate	rr_f	3.30%	3.10%	3.35%	3.03%
Expected inflation	f	2.50%	2.90%	2.69%	2.19%
Nominal risk free rate	r_f	5.85% 10 year rate	6.00% 5 year rate	6.13% 10 year rate	5.29% 5 year rate
Gearing					
Debt to total assets	D/(D+E)	60%	60%	60%	60%
Taxation					
Corporate tax rate	T	36%	30%	30%	30%
Effective tax rate	T_e	36%	13.6%	30%	23.5%[(a)]
Value of imputation credits	γ	0.4-0.5	0.5	0.5	0.5
Return on equity					
Equity beta	β_e	1.20-1.45	1.16	1.45	1.00
Market risk premium	MRP	6.0%	6.0%	6.0%	6.0%
Post-tax nominal return on equity	r_e	13.1-14.6%	13.0%	14.8%	11.3%
Post-tax real return on equity	rr_e	10.3–11.8%	9.8%	11.8%	8.9%
Cost of debt					
Debt margin	DM	1.3-1.4%	1.2%	1.20%	0.92%
Nominal cost of debt	r_d	7.3-7.4%	7.2%	7.33%	6.20%
Real cost of debt	rr_d	4.6-4.7%	4.2%	4.52%	3.92%
WACC estimates					
Post-tax nominal WACC[(b)] $W = r_e\,[(1-T_e)/(1-T_e(1-\gamma))].E/V + r_d\,(1-T).D/V$		6.9-7.6%	7.9%	8.0%	6.5%[(a)]
Pre-tax nominal WACC[(b)] $W_t = r_e\,/(1-T_e(1-\gamma)).E/V + r_d\,D/V$		10.6-11.8%	9.9%	11.4%	8.8%[(a)]
Pre-tax real WACC[(b)] $W_{tr} = (1+W_t)/(1+f)-1$		7.9-9.0%	7.0%	7.9%	6.56%[(a)]
Nominal vanilla WACC $W_v = r_e.E/V + r_d.D/V$		9.6-10.2%	9.5%	10.3%	8.2%

Source: Original access arrangement information, May 1999, Revised access arrangement information, July 2003, ACCC *Draft Decision* and ACCC analysis.

Notes: (a) Derived for the mainline segments of the pipeline

(b) EAPL's proposed WACCs are formula-based. The Commission's are derived from cash flow analysis.

2.7 Non capital costs

2.7.1 Code requirements

Non capital costs are the operating, maintenance and other costs incurred in the delivery of a reference service (section 8.36). Non capital costs may include, but are not limited to, costs incurred for generic market development activities aimed at increasing long term demand for the delivery of the reference service.

A reference tariff may provide for the recovery of all non capital costs (or forecast non capital costs, as relevant) except for any that would not be incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the reference service (section 8.37).

As set out in the following paragraphs, EAPL has proposed to recover certain costs through its proposed reference tariff. The Commission's task is to form a view as to whether the proposed costs are consistent with those that would be incurred by a prudent service provider acting in accordance with section 8.37.

In relation to forecast non capital costs, the Commission must be satisfied that the forecasts represent best estimates arrived at on a reasonable basis. In the case of uncertainty further guidance is found in section 8.1 and section 2.24 of the Code.

2.7.2 Original access arrangement

The various components of the forecast non capital costs proposed by EAPL in 1999 for the initial access arrangement period are shown in Table 2.7.2.1 and a summary of the various items comprising each category is contained in Box 2.7.2.1.

Table 2.7.2.1: Forecast non capital costs (July 2000 $000)

Year ending 30 June	**2001**	**2002**	**2003**	**2004**	**2005**
Labour	5 393	5 546	5 699	5 783	5 868
General administration	3 249	3 265	3 280	3 297	3 313
Materials	1 285	2 202	1 180	2 369	1 059
Communications systems	1 163	1 168	1 175	1 180	1 186
Gas used	900	797	799	727	730
Licences	189	184	185	185	187
Return on working capital	85	92	86	95	86
Total	**12 264**	**13 255**	**12 406**	**13 636**	**12 430**

Source: EAPL access arrangement information, 5 May 1999, p. 41.
Note: Totals may not add up due to rounding.

Box 2.7.2.1: Summary of the components of EAPL's 1999 proposed operating and maintenance cost

Labour

Includes the wages, salaries and on costs of 91 full time staff and the costs of contract labour. The number of full time employees is predicted to rise to 93 by the end of the initial access arrangement period in response to the additional workload associated with third party access (for example, processing customer nominations and marketing activities).

General administration

Includes administrative and audit fees, cost of insurance, advertising expenses, aircraft expenses, bank charges, cleaning, communications (other than system lease costs) and computing costs.

Materials

Comprises ongoing maintenance directly associated with the transmission of gas. Also included are provisions for the following major works:

- $0.25 million repairs to compressor unit in 2000/01;
- $1.2 million major overhaul of compressor unit in 20001/02; and
- $1.2 million major overhaul of compressor unit in 2003/04.

Communications system

Annual operating lease expenditure on Telstra's communication network.

Gas used

Mainly gas used as compressor fuel.

Pipeline licence fees

Fees imposed New South Wales, South Australia, Queensland and ACT governments.

Working capital

EAPL has included a nominal return of 11.1 per cent on working capital.

Source: EAPL access arrangement information, 5 May 1999, pp. 38-42.

In its original access arrangement EAPL stated that costs were low in comparison with available benchmarks and represent the efficient cost of operating the MSP. EAPL claimed that these efficiencies had been achieved through a cost reduction program implemented from 1994 (when the company purchased the pipeline) to 1998. The program resulted in full-time equivalent staff numbers falling from 125 to 92 and overall costs being reduced from $9.94 to $6.28 per kilometre.

EAPL provided KPIs in support of its proposed operating costs, (See chapter 4 of this *Final Decision*) and concluded that its costs compared favourably when contrasted with operating costs of other Australian company pipeline companies (as shown in Table 2.7.2.2).

Table 2.7.2.2: Operating costs comparisons (1999)

	EAPL	Epic	AGLP	TPA	TPA	Alinta Gas	Pipeline Authority	PASA
State	NSW	SA	NSW	VIC	VIC	WA	NSW	SA
Year	2001	1999	99/00	1999	95/96	95/96	64/95	94/95
$m/1 000 km	6.06	7.34	2.8	11.0-16.0	9.9	13.6	10.4	10.1

Source: EAPL access arrangement information, 5 May 1999, p. 65.

Notes: Epic refers to Epic Energy South Australia Pty Ltd, AGLP refers to AGL Pipelines (NSW) Pty Limited, TPA refers to Transmission Pipelines Australia, and PASA refers to Pipelines Authority of South Australia.

Working capital

EAPL's original access arrangement included within its forecast non capital costs a nominal rate of return on working capital. In support of the proposal EAPL observed that inflation erodes the value of working capital over time and as such the Commission should allow for a nominal rate of return of 11.1 per cent as a component of its non capital costs.[270] EAPL calculated its working capital requirements at 23 days, which it argued was less than the 45 days rule of thumb adopted by many regulatory authorities in the United States.

Gas used

Subsequent to the submission of the original access arrangement, EAPL advised that its fuel gas purchase contract had expired and that the company was considering alternate arrangements in regard to the supply of fuel gas. EAPL proposed that a more standard and equitable approach would be for shippers to provide their own fuel gas at the receipt point and requested that the issue be raised for discussion in the *Draft Decision*.[271]

2.7.3 Submissions in response to the original access arrangement

The Commission received a number of submissions in response to EAPL's proposal that to shippers to provide their own fuel gas at the receipt point, these submissions are discussed in section 3.2 (terms and conditions) of this *Final Decision*. The Commission did not, however, receive any submissions suggesting that EAPL's proposed non capital costs were too high. However, Innovative Energy Australia (on behalf of Incitec), was critical of EAPL's direct comparisons of operating costs among Australian pipelines because of different levels of compression and the associated costs. In this regard Innovative Energy Australia raised two issues:

- since the MSP had only two compressors installed, its operating costs are likely to be lower than other pipelines with a greater degree of compression; and

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270 This is consistent with EAPL's proposed real pre-tax WACC of 8.4 per cent.

271 EAPL letter to the Commission, 21 September 2000, p. 4.

- even if the degree of compression were comparable, distortions would still arise because of differences in the cost of gas used in compression, which is a major operating cost.[272]

Innovative Energy Australia also stated that the data presented by EAPL as set out in Table 2.7.2.2 illustrates the benefits of privatisation and the relationship between operating costs with regards to compression, but little about the performance of EAPL with respect to world's best practice.[273]

2.7.4 Commission's Draft Decision

In considering EAPL's proposed non capital costs and various submissions the Commission noted that the Code requires the regulator to allow only the prudent costs (and not necessarily actual costs) which a service provider would incur when acting consistently with the Code. The Commission acknowledged the efficiency gains made by EAPL since its acquisition of the MSP in 1994 and the favourable comparison of forecast costs (2001 to 2005) with actual costs (1995 to 1998). The Commission noted that while the gains were not conclusive evidence that the non capital costs proposed by EAPL represented the prudent costs of delivering the reference services, and EAPL did not make this claim, they were however indicative of the action taken by EAPL to produce transmission services at a lower cost.

In its considerations the Commission noted that EAPL's submission of its forecast non capital costs was prior to the float of AGL gas transmission assets in June 2000. The *Draft Decision* did not speculate on the likely impact of the restructuring of AGL on the MSP's costs. Instead, the Commission confined its assessment to the reasonableness of the forecast non capital costs contained within the access arrangement information submitted by EAPL. This not withstanding, the Commission noted that any consequent difference in costs arising out of the restructure could be viewed as a benefit (or loss) that EAPL would retain (wear).

Cost of materials

The *Draft Decision* noted that under EAPL's original access arrangement the costs associated with the major overhaul of two compressors were allocated to the materials component of forecast non capital costs.[274] The Commission's view was that while it was more appropriate for these items to be added to the asset value of the compressors and depreciated over their remaining life, EAPL's accounting practice had been to expense these items over the period in which they occurred. The Commission did not consider that capitalising these costs (rather than expensing them) would be likely to have a significant impact on tariffs. Accordingly, the Commission decided to accept EAPL's proposed treatment of these costs.

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272 Incitec submission, 18 August 1999, p. 4.

273 Incitec submission, 18 August 1999, p. 4.

274 Both compressors are estimated at $1.2 million each. One occurring in 2000/01 and the other in 2003/04.

Working capital

The Commission assessed EAPL's proposal to include an explicit allowance for a return on working capital and after due consideration decided not to allow its inclusion. The rationale for the Commission's position related to the methodology adopted in the modelling of cash flows. Rather than model the timing of EAPL's cash flows throughout the year, the Commission assumes in its model that all costs and revenue are incurred on the last day of each year. In reality, EAPL's cash flows would occur at regular intervals throughout the year, giving EAPL a benefit above the regulated revenue equal to the time value of money on the net cash flow received throughout the year. The Commission considered that this benefit would more than compensate EAPL for any gap between payments and collections during the year. Accordingly, the Commission proposed an amendment requiring EAPL to remove the allowance for working capital from its non capital costs.

In support of its proposed operating costs, EAPL provided key performance indicators suggesting that the operating costs of the MSP compared favourably with other transmission pipeline systems. However, as alluded to by Innovative Energy Australia there are limitations to benchmarking and inter-company comparisons.

The Commission noted that based on ORC, EAPL's total operating and maintenance costs were approximately 1.3 per cent of capital costs. On the basis of the information available to it, the Commission concluded that EAPL's operating and maintenance costs were reasonable.

2.7.5 Submissions in response to the Draft Decision

The Commission did not receive any submissions from interested parties in response to its proposed amendment set out in the *Draft Decision.*

2.7.6 Revised access arrangement

The revised access arrangement information submitted by EAPL in May 2002 outlined a substantial increase in non capital costs from those originally submitted in 1999. EAPL originally proposed non capital costs of approximately $12.8m per annum in real terms (July 2000 dollars). However, in the revised access arrangement these forecast costs had increased $23.1m per annum (July 2002 dollars). These costs are set out in Table 2.7.6.1 and Table 2.7.6.2 below.

Table 2.7.6.1: Forecast operating expenditure (July 2002[(a)] $ million)

Year ending 30 June	2004	2005	2006	2007	2008
Marketing	1.69	1.67	1.65	1.64	1.62
Operations & Maintenance	17.93	17.81	17.79	17.76	17.73
General & administration	3.56	3.60	3.65	3.69	3.74
Total	**23.18**	**23.09**	**23.09**	**23.09**	**23.09**

Source: EAPL response to Commission, 20 June 2002.

Notes: (a) Although EAPL's revised access arrangement information (7 July 2003) stated that this data was for the2001 financial year according to its models the base year is actually 2002

Table 2.7.6.2: Forecast operating expenditure by detailed expenditure category (July 2002[a] $ million)

Year ending 30 June	2004	2005	2006	2007	2008
Labour	0.25	0.25	0.26	0.27	0.27
Corporate Overheads	2.12	2.17	2.21	2.26	2.30
Materials(& Supply)[b]	20.64	20.50	20.47	20.40	20.35
Communications Systems	0	0	0	0	0
Gas Used	0	0	0	0	0
Licences	0.17	0.17	0.17	0.17	0.17
Total	**23.18**	**23.09**	**23.09**	**23.09**	**23.09**

Notes: (a) Although EAPL's revised access arrangement information stated that this data was for the 2001 financial year according to its models the base year is actually the 2002 financial year.
(b) Including services provided by others.
Source: EAPL revised access arrangement information, 7 July 2003, p. 22.

In accounting for the increase, EAPL advised that there had been a change in the ownership and operation of the MSP since the original access arrangement was submitted. EAPL contended that its new cost structures reflected:

- the establishment of APT (EAPL's beneficial owner) as a stand alone listed entity which resulted in the inclusion of a number of new costs including an allowance for corporate overheads; and
- the outsourcing of operational activities, management and marketing services to Agility and Petronas. EAPL had previously benefited, at no charge, from the significant technical expertise held within AGL, however, under the new arrangements EAPL would be charged for this expertise by Agility.

In addition, EAPL attributed part of the increase to higher insurance costs flowing from the impact of 11 September 2001 and the disposal of $5 million in assets previously used in the operations and maintenance of the MSP.[275]

EAPL's revised access arrangement information of July 2003 provided the following details of each of these elements:

- *Overhead costs* of $2.2 million per annum relate to insurance, directors fees, regulatory activities, compliance and general corporate governance, personnel and training, legal, accounting, taxation and government levies. In its proposal to include $2.2 million per annum of corporate overheads in the operating costs of MSP, EAPL advised that:

> Operating costs in EAPL's 1999 Access Arrangement were EAPL's actual cost and as the new owners of EAPL (APT) understands such costs did not include corporate overheads that covered such items as the cost of APT's Board, corporate structure and other costs associated with operating as a listed entity. Until the formation of EAPL, AGL, and the other owners of EAPL at the time incurred these corporate overheads.[276]

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275 EAPL response to Commission information request, 20 June 2002, p. 8.

276 EAPL revised access arrangement information, 7 July 2003, p. 21.

- *Contracted management and services:* EAPL advised the Commission that it had outsourced a substantial proportion of its operational activities to Agility, (an AGL subsidiary). The terms of the outsourcing contract required Agility to provide asset management services and field services for each of APT's pipelines. As a consequence, a significant proportion of EAPL's operations and maintenance work is carried out by Agility. These activities include the operation and control and maintenance of the pipeline, pipeline right of way, pipeline facilities, compressor stations, maintenance of the SCADA and communications system and regulation metering and gas measurement equipment.[277]
- *Marketing costs*: EAPL advised that the $1.6 million per annum in sales and marketing costs were related to the development and promotion of gas transportation, investigation and feasibility studies for potential gas consuming projects, commercial negotiations relating to gas transportation services and general contract management and administration activities.[278]
- *Increase in insurance:* EAPL's submission identified an increase in insurance costs as a result of the events of 11 September 2001.[279]
- *Disposal of assets:* EAPL advised that at the time of the establishment of APT and associated outsourcing arrangements, it had disposed of various assets used in the performance of operations and maintenance services.[280] These assets include the SCADA system, motor vehicles, tools, plants and mobile equipment which were deemed to have a disposal value of $5 million. EAPL noted that while the MSP's capital base has been adjusted, the disposal has resulted in an increase in overall operating expenditure. EAPL advised that it was unable to provide details of the exact increase in costs associated with the disposal of these assets, as the services associated with each item were part of an overall management and services agreement and this agreement did not specify the charges for the services provided by the assets.[281]

Offsetting some of these additional non capital costs proposed in the revised access arrangement has been the removal of certain proposed non capital costs associated with original access arrangement:

- the $750 000 per annum allowance for system use gas, now to be provided by users;
- $90 000 annual allowance for a return on working capital; and
- an allowance of $2.4 million for the overhaul of two compressor units, the latter now being incorporated into forecast capital expenditure.

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277 EAPL revised access arrangement information, 7 July 2003, p. 20.

278 EAPL revised access arrangement information, 7 July 2003, pp. 21,22

279 EAPL response to the Commission, 20 June 2002, p. 8.

280 EAPL response to the Commission, 20 June 2002, p. 8.

281 EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 2.

Impact of the AGL announcement

In January 2003 EAPL requested the opportunity to review the operating costs submitted in May 2002 following AGL's announcement (in December 2002) of its new portfolio of gas supply contracts. EAPL stated that the impact of the new contracts be a 35 per cent reduction in volumes to be transported on the MSP (through to 2022) and could potentially affect certain tariff elements of the access arrangement, including operating and capital expenditure.

EAPL subsequently advised the Commission that after reviewing the potential impact of the downward revisions to volumes it had concluded that there would be no changes to the non capital costs proposed in May 2002.[282]

2.7.7 Submissions in response to revised access arrangement

In response to EAPL's proposed non capital costs TXU noted that:

> …since EAPL first lodged its Access Arrangement Information in May 1999, it has increased operating expenditure estimates from approximately $12 m to $23 m, without detailed explanation. As it is difficult to make meaningful comment in these areas without additional explanatory material, we ask that the Commission carefully review EAPL's proposals and confirm that it is satisfied that the proposed operating expenditures are fair and reasonable.[283]

2.7.8 Commission's considerations

As noted earlier, EAPL's original access arrangement proposed non capital costs of approximately $13 million per annum. The Commission was advised at the time that these were the efficient costs of operating the MSP. However, following the restructuring of AGL's business interests which resulted in the establishment of APT and Agility, non capital costs have been revised upward to approximately $23 million per annum. EAPL now contends that the revised costs represent the efficient cost of operating the MSP.

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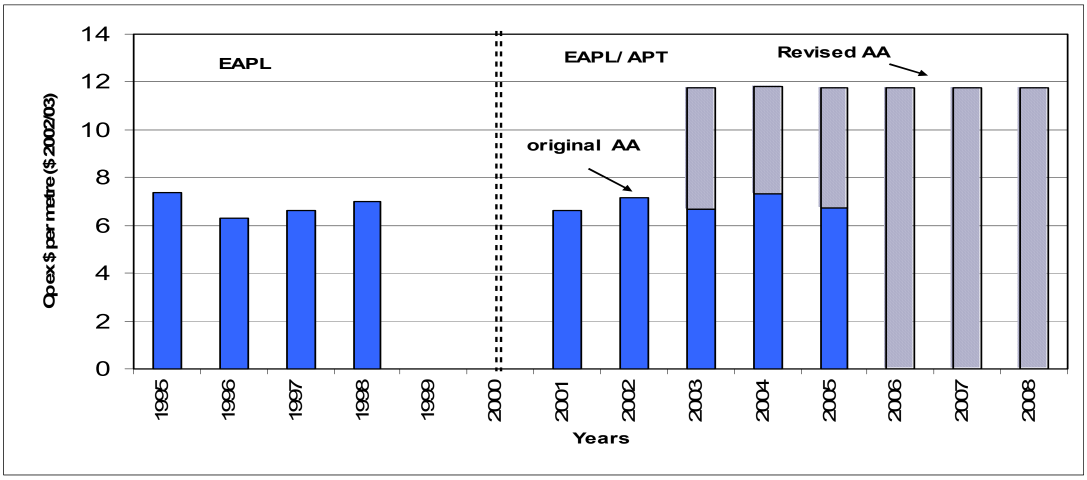
[282] EAPL response to the Commission, 2 July 2003.

[283] TXU submission, 18 August 2002, p. 10.

Figure 2.7.8.1: Changes in proposed non capital costs



Source: ACCC, *Draft Decision: MSP*, 19 December 2000, p. 86; EAPL revised access arrangement information, 7 July 2003 and Commission modelling.

As the graph above illustrates, actual and forecast non capital costs have changed substantially over the period 1995 to 2008. During the period 1995-1998, EAPL was owned by AGL and Gasinvest Australia. Actual operating costs averaged approximately $7 per km ($2002/03) during that time. It was under this ownership structure that EAPL submitted its original access arrangement in 1999 for the period 2001-2005. As Figure 2.7.8.1 shows, proposed non capital costs for this period are not significantly different, in nominal terms, from actual cost for 1995-1998[284].

However, when EAPL submitted its revised access arrangement in May 2002 (subsequent to ownership changes), non capital cost forecasts had almost doubled on a per kilometre basis. The Commission notes that the disparity is higher still (by $6.15 million for the 2004-2008 revised access arrangement period) if costs relating to the allowance for system use gas, working capital and the major overhaul of the two compressor units (as included in the original non capital costs) were also included in the revised costs.

The Commission has approached EAPL on numerous occasions (see section 1.5 of this document) requesting further information to support the significant increase in non capital costs. In doing so the Commission has made every effort to reconcile the differences between the two sets of forecasts and also provide EAPL further opportunities to substantiate the claim that the revised costs for the MSP reflect its efficient costs.

EAPL has contended that a number of factors have contributed to the increase in non capital costs. Specifically, these are: corporate overheads associated with the establishment of APT; an increase in insurance premiums subsequent to 11 September 2001; and the formation of a substantial outsourcing contracts with Agility and Petronas.

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[284] The Pipeline Authority annual reports, 1974-1994 and EAPL Financial Statements submitted to the Australian Securities and Investments Commission, 1995-2000.

In assessing EAPL's revised non capital costs the Commission notes that section 8.37 of the Code requires the regulator to allow only the prudent costs (and not necessarily actual costs) that would be incurred by a service provider acting efficiently and in accordance with accepted and good industry practice.

Corporate overheads

EAPL has advised that since the APT float it has operated as a stand alone business and accordingly a portion of the increase in costs between the original and revised access arrangements can be attributed to its share (totalling $2.1 million) of APT's total corporate overheads. Prior to the establishment of APT, these costs were borne by EAPL's previous owners AGL, Petronas and Novacorp.[285]

The Commission has considered APT's method of allocating shared corporate overheads (further discussion in contained in confidential Appendix E) and notes that at the time of the APT float in June 2000, the APT prospectus reported that the total value of its assets were $1 366.8 million.[286] In addition, EAPL's statutory accounts for the 30 June 2000 valued the MSP total assets at $473 million. The Commission notes that while the book value of the MSP represented 35 per cent of the total value of APT assets at June 2000, the APT prospectus claims that the MSP would contribute 53 per cent of APT's total earnings before tax and depreciation allowance for the two years ending 30 June 2002.[287]

While the corporate overheads proposed by EAPL may meet the section 8.37 criteria of the Code, the Commission notes that the value of a company within a group of assets (such as APT) and that company's contribution to group total revenue will change over time. As such, the Commission will continue to review the appropriateness of APT's method of allocating corporate overheads to its regulated entities in subsequent access arrangement reviews.

Increase in insurance premiums

EAPL's submission identified an increase in insurance costs (resulting from the events surrounding 11 September 2001) as one of the factors driving its increased non capital costs. EAPL has also claimed confidentiality in regard to its insurance costs. Accordingly, further discussion on this issue can be found in confidential Appendix E of this document. In its assessment of costs the Commission noted a near doubling of insurance costs and requested that EAPL demonstrate evidence of this increase and provide a copy of the MSP's insurance invoice.[288] Having received this information the Commission is satisfied that the insurance costs proposed by EAPL for the initial access arrangement period meet the criteria of section 8.37.

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285 EAPL response to the Commission request for additional information, 26 May 2003, p. 4.

286 APT, *Buried Treasure – Offer document*, March 2000, p. 13.

287 APT, *Buried Treasure – Offer document*, March 2000, p. 28.

288 EAPL facsimile to Commission, 12 June 2003, p. 2.

Outsourcing of management, services and marketing

It should be noted that between 1999 and March 2000 AGL (a significant shareholder in EAPL) purchased Trans Canada's share of EAPL. During this sale, AGL reached an agreement with Petronas to include its share of the MSP in the float of AGL transmission pipeline assets. At the time Petronas entered an agreement to provide marketing services to the MSP and the CWP for $1 million per annum. This agreement was entered into prior to the float of the APT.[289]

During the same period AGL established Agility, a wholly owned subsidiary, to supply comprehensive pipeline management and field services to APT companies over a 20 year period under the Pipeline Management Agreement (PMA) for a substantially bundled fee. The agreement came into effect in April 2000 and covered fees for a number of actual services plus a fixed $6 million per annum fee called the PMA management fee. This fee is set to rise on a quarterly basis by 75 percent of CPI.[290]

As a result of the above, two agreements with EAPL affiliates (Agility (by virtue of AGL's ownership) and Petronas) now underpin a substantial number of services (and therefore a substantial amount of non capital costs) to the MSP. It does not appear that the agreements were established through an arm's length transaction or were market tested in a transparent manner. Consequently, the Commission has considered whether the fees payable under the agreements are consistent with the requirements of section 8.37.

Pipeline Management Agreement

The Commission notes that the PMA was initially an agreement between AGL Pipelines and AGL Infrastructure Management Pty Limited (AGLIM). These have since been renamed APT Pipelines and Agility Management Pty Limited (Agility) respectively. EAPL has requested that certain details of the PMA remain confidential. The Commission has agreed to this request and has set out its detailed discussion on the agreement in confidential Appendix E of this *Final Decision*.

Under the PMA, Agility provides the following services to APT:

- Specified Services. These include specified marketing and technical services in respect of specified pipelines; and
- Additional Services. These include a number of further marketing and technical services.

The Commission notes the comprehensive nature of the services provided under the PMA and therefore its substantial influence (both in terms of amount and structure) on the MSP's total non capital costs. As such the Commission has considered both the PMA in its entirety and as separate components.

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289 APT, *Buried Treasure – Offer document*, March 2000, p. 13

290 APT, *Buried Treasure – Offer document*, March 2000, p. 64.

Assessment of the PMA

In assessing EAPL's non capital costs, the Commission noted with some interest EAPL's claim that 'there are no readily achievable efficiency gains to be made which would significantly reduce the operating expenditure forecast'.[291] In considering this statement the Commission assessed the degree of flexibility (and the opportunity) afforded to EAPL in its outsourcing agreements to capture and realise any efficiency gains. The Commission found that a significant percentage of EAPL's non capital costs could be described as fixed costs given the terms of the two agreements in place. Furthermore, the majority of EAPL's non capital costs relate to services carried out pursuant to the PMA and are therefore billable by Agility.

The inflexibility in EAPL's cost structure is evidenced not only in the terms of the PMA but also in the fact that despite forecasting a sizable reduction in throughput (and therefore revenue) and capital expenditure, EAPL has not made a downward adjustment to its forecast operational expenditure.

This current inflexibility in EAPL's cost structure was not apparent under the previous arrangements. EAPL's original access arrangement information advised that:

> O&M costs are more responsive than asset costs to throughput changes, and in the long term the proportion variable charges will, likely increase. However in the medium term, the proportions of variability are estimated ….labour – 50%, General Administration – 20%, Materials- 50%.[292]

The Commission is aware that while the PMA is a 20 year agreement, it does allow for APT and Agility to renegotiate various aspects for the following five year period of the PMA (2005-2010). While the contract affords EAPL this opportunity, the Commission observes from forecast costs that EAPL does not anticipate the total cost of services provided under the PMA to change substantially in the 2005-2010 period. Consequently, the Commission has concerns that the contractual arrangements of the PMA allow EAPL little flexibility to restructure its 'actual' non capital costs to adjust to changing market conditions or to capture any potential efficiency gains which will be substantially retained by Agility.

Agility (on behalf of EAPL) has contended that the bulk of the services provided under the agreement are covered by a fixed agreed charge, and as such it is Agility that bears the risk of any increased costs of operating the MSP which may have been unforeseen at the time of the float.[293]

The Commission agrees that for Agility, the downside risk of a contract with fixed terms is that costs may increase over time above those initially anticipated. However, the Commission notes that from EAPL's point of view there is also downside risk that the actual costs of performing the contract may 'decrease' over time and so EAPL will pay an excessive amount for the service performed by Agility.

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[291] EAPL revised access arrangement information, 7 July 2003, .p. 20.

[292] EAPL access arrangement information, 5 May 1999, p. 49.

[293] EAPL letter to the Commission, 15 April 2003, p. 3.

One example of the downside risk facing EAPL under the PMA is the case of volumes. As stated by EAPL, 'the charges in the PMA generally reflect the actual historical costs inherent in each of the pipelines prior to the establishment of the APT'.[294] EAPL established the PMA in April 2000 using historical data despite the fact that it was aware of the future potential loss of volumes by MSP to EGP. This loss of volumes formed the basis of the application to the NCC for revocation of coverage in April 2000. Accordingly, should throughput fall below historic volumes as predicted, Agility (an unregulated entity) will benefit from decreasing actual costs of performing the contract and not EAPL (a regulated entity). However under the terms of the PMA, EAPL would still be required to (effectively) pay the original amount in accordance with the higher volumes that the contract was based on.

The Commission is also of the view that Agility is better positioned than EAPL to mitigate any downside operational risks (that is, costs 'blow outs') given the comprehensive nature of its services for the pipeline. Agility also has the incentive to capture any upside operational risk (cost savings).

The Commission also notes that under the terms of the PMA costs such as insurance (that have seen significant increases in recent years) do not fall under the fixed fee component of the contract. While insurance costs are negotiated by Agility (on behalf of the APT group of pipelines) the costs are passed directly through to EAPL and therefore EAPL and users continue to bear some downside risks.

The Commission considers that a contract for such a comprehensive suite of services for substantially fixed costs, that provides little opportunity to capture efficiencies, nor adapt to changing economic conditions may not meet the requirements of section 8.37 of the Code.

Management Fee

The service for which Agility receives the management fee under the terms of the PMA is not specified. However, a significant proportion of this $6 million annual fee is allocated to the MSP. It appears that while Agility charges separately for various services performed under the PMA, the management fee however is not for any particular service. The Commission has considered further aspects of the management fee within the terms of the PMA and provides its detailed considerations in Confidential Appendix E of this document.

In conclusion, the Commission considers the management fee is a cost that would not be incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the reference service as is required by section 8.37 of the Code.

Petronas marketing fee

The Commission recognises that sales and marketing costs are genuine non capital costs which a service provider is able to recover. Nevertheless, it has some concerns with the magnitude of the costs claimed by EAPL in this instance. Under the revised

294 EAPL letter to Commission, 15 April 2003, p. 8.

access arrangement EAPL has proposed $1.7 million per annum for sales and marketing. The Commission notes that these costs are incurred from two sources, Petronas and Agility, and that functions are undertaken by a staff member from each affiliate. As EAPL has claimed the breakdown of its marketing costs to be confidential, further details are set out in Appendix E of this document.

In considering whether the $1.7 million per annum proposed by EAPL would meet the criteria of section 8.37 of the Code, the Commission has:

- examined the sales and marketing costs incurred by other pipelines;
- considered the circumstances surrounding the outsourcing of the sales and marketing function; and
- considered the extent to which the payment is linked to performance or allows for any efficiencies to be captured by EAPL.

With respect to the first of these points, the table below demonstrates that the sales and marketing costs proposed by EAPL are nearly four times that of other service providers, despite the fact that majority of the MSP's throughput is covered by only the one agreement, the GTD.

Table 2.7.8.1: Comparison of marketing costs for transmission pipelines ($ million)

Year ending 30 June	2004	2005	2006	2007	2008
MSP[(a)] - (2002 $ million)	1.69	1.67	1.66	1.64	1.62
GasNet[(b)]	0.40	0.40	0.40	0.40	0.40
ABDP[(c)]	0.15	0.15	0.15	0.15	0.16
Epic- DBNGP- (1999 $ million)[(d)]	0.44				

Source: (a) EAPL revised access arrangement information, 7 July 2003, p. 22.
(b) ACCC, *Final Decision: GasNet*, 13 November 2002, p. 132; ACCC, *Draft Decision, GasNet*, 14 August 2002.
(c) ACCC, *Final Decision: ABDP*, 4 December 2002, p. 98.
(d) Independent Gas Pipelines Access Regulator, Office of Gas Access Regulation, WA, *Final Decision on the Proposed Access Arrangement for the Dampier to Bunbury Pipeline System: Submitted by Epic Energy (WA) Transmission Pty Ltd,* 23 May 2003, p. 83.

Second, as noted previously, the Commission has concerns with the circumstances surrounding the outsourcing arrangements of this function and the fact that it was not the result of an arms' length transaction or was market tested in any transparent way. The APT prospectus states:

> Petronas Australia has contracted to provide marketing services in respect of the Moomba to Sydney Pipeline System (including Central West Pipeline) for which it will receive a fee of $1 million per annum[295]

[295] APT, *Buried Treasure – Offer document*, March 2000, p. 13

The Commission notes that the fee does not appear to be linked in anyway to performance as it remains relatively constant despite a forecast drop in throughput (sales) on the MSP. However, as set out previously, at the time these contracts were entered into it was reasonably foreseeable that volumes transported on the MSP may fall as a result of the construction of the EGP. Consequently the Commission considers that this contract has the effect of transferring the risk of underperformance (that is not maintaining or growing the market) to EAPL while providing Petronas with the ability to capture any cost savings. As with the PMA this contract is fixed in nature which adds to the already inflexible nature of MSP's non capital costs.

After due consideration of the above issues, the Commission is not satisfied that Petronas marketing fee, in addition to the fee payable to Agility, would be incurred by a prudent service provider acting efficiently as is required under section 8.37 of the Code.

Commission's conclusions on the outsourcing arrangements

Overall, the Commission has some fundamental concerns with the outsourcing arrangements put in place at the time of the APT float for the MSP. Specifically, the Commission is concerned with:

- the apparent absence of any transparency in the costing of the outsourced services;
- the fixed nature of these agreements and the impact this has had, and will continue to have, on the flexibility of the pipeline operations and the ability to capture and realise any efficiency gains; and
- the magnitude of these additional costs and the lack of information provided by EAPL to demonstrate that the significant increase in costs would have been incurred by a service provider acting efficiently and prudent.

On the information currently before the Commission it appears that the proposed costs in their entirety do not meet the criteria in section 8.37 of the Code. That is, they do not appear to reflect the prudent costs which would be incurred by a service provider acting efficiently in accordance with accepted and good industry practice.

In support of this view the Commission refers to results of some benchmarking analysis undertaken. The Commission recognises the limitations of benchmarking and, in particular, the debate surrounding which parameters should be used as normalising factors. While various benchmarking parameters are discussed in more detail in the relevant sections of this *Final Decision*, the Commission considers that as the end costs to users is a product of throughput (volume) and distance, that a measure of non capital cost/km/PJ may provide a useful indicator to compare EAPL's non capital costs with other pipelines. The Commission is also aware of the care that needs to be exercised in carrying out any comparisons across entities. For these reasons, the Commission has sought to compare non capital costs excluding system use gas and compressor maintenance costs.[296] This is illustrated in Figure 2.7.8.2.

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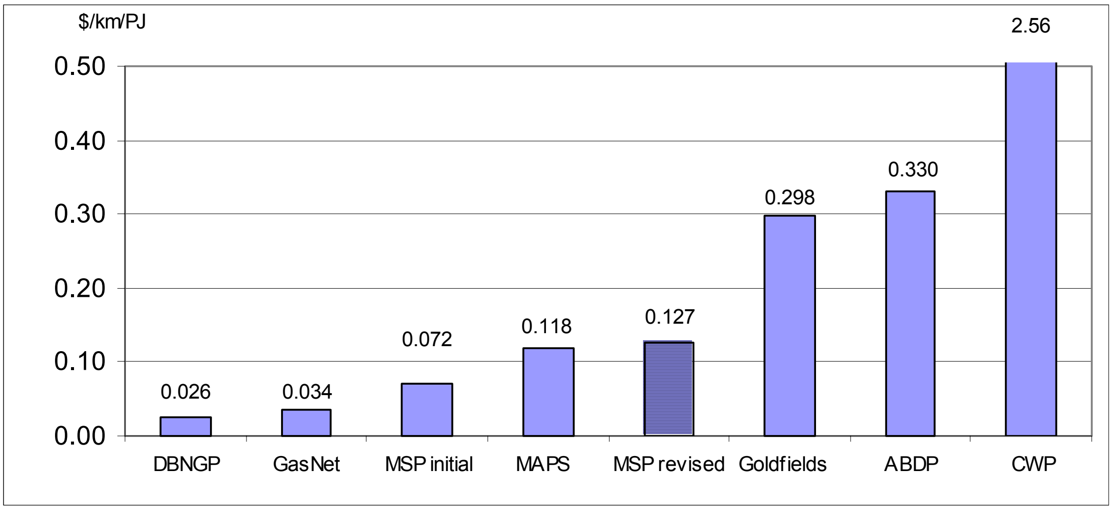
[296] Compressor maintenance has not been excluded from the MAPS, ABDP and the Goldfields Gas Pipeline given data limitations.

Figure 2.7.8.2: Non capital costs (less compressor maintenance costs and fuel costs) per km per PJ



Source: Commission’s calculations

As the chart above indicates, against this KPI the MSP ranks in the middle of the range, and is below the average and median figures. Higher non capital costs are incurred on the ABDP, the Goldfields Gas Pipeline and the CWP, all of which are characterised by relatively small diameter and relatively small gas throughput. These pipelines are now serviced by Agility under the PMA. Non capital costs on the MSP are higher than those on more comparable pipelines, namely the DBNGP, the GasNet System and the MAPS (which, due to data limitations, includes compressor maintenance costs). Accordingly, this benchmark provides some secondary support to the view that EAPL’s costs may exceed those that would be incurred by an efficient and prudent service provider.

Table 2.7.8.2 sets out the non capital costs (in real terms) as adjusted by the Commission for the initial access arrangement period. Accordingly, as indicated in the amendment below, these costs are to be adopted by EAPL for the MSP.

Table 2.7.8.2: Commission approved non capital costs (July 2003 $ million)

Year ending 30 June	**2004**	**2005**	**2006**	**2007**	**2008**
Total non capital costs	18.57	18.62	18.76	18.91	19.05

Amendment FDA 9

In order for EAPL’s access arrangement for the MSP to be approved, EAPL must adopt the non capital costs set out in Table 2.7.8.2 of this *Final Decision*.

2.8 Forecast volumes

2.8.1 Code requirements

The Code provides for the use of forecast volumes in deriving total revenue (section 8.4) and setting reference tariffs (sections 8.38 to 8.41). In instances where forecasts are used to set reference tariffs, section 8.2(e) of the Code requires the regulator to be satisfied that the forecasts represent best estimates arrived at on a reasonable basis.

2.8.2 Original access arrangement

EAPL's original access arrangement contained projections for both total gas demand in NSW and the ACT and aggregate gas throughput for the MSP over the period 1999 – 2014. These forecasts, in addition to those provided by DEI, are set out in Table 2.8.2.1 below.

The forecasts submitted by EAPL were derived using both confidential information from customers and a composite of independent forecasts from several sources including: the Australian Gas Association (AGA); the Australian Bureau of Agricultural and Resources Economics (ABARE); and the National Electricity Market Management Company (NEMMCO).

Table 2.8.2.1: Original forecast volumes of gas by destination and source (PJ)

			Access Arrangement Period								
	1999	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2008**	**2010**	**2014**
Total NSW/ACT demand											
EAPL estimate	111.8	109.6	109.4	113.3	117.4	124.1	138.9	159.1	179.7	196.4	211.2
DEI estimate		105.1	110.0	115.0	120.0	130.0	141.0	148.1	159.4	174.1	196.3
MSP throughput											
Deliveries ex Moomba into NSW/ACT/ VIC	117.7	117.2	97.4	86.8	87.4	79.9	80.9	98.1	108.7	123.4	175.2
Interconnect deliveries into NSW/ACT	0.0	0.0	2.0	3.0	4.0	10.0	17.0	20.0	22.0	24.0	23.0
Total MSP	117.7	117.2	99.4	89.8	91.4	89.9	97.9	118.1	130.7	147.4	198.2

Sources: Access arrangement information, May 1999, p. 13,
Supplementary access arrangement information, October 1999, p. 2,
Information supplied by EAPL to the Commission.
Duke Energy, *Submission to ACCC for Development of an Undertaking for Access to the Eastern Gas Pipeline,* 15 November 1999, p. 5.

The forecasts were also predicated on a number of specific assumptions as set out below.[297]

Residential, commercial and industrial demand (conventional demand) in NSW and ACT

The specific assumptions made by EAPL were that there would be strong growth in the residential and small commercial market but that this would be more than offset by a slowdown in industrial gas demand and a lack of new energy intensive industries. According to EAPL this would result in static demand in NSW and the ACT over the period 1997 – 2002. EAPL also assumed opportunities would emerge for growth in gas demand in the minerals processing, heavy industry and other industrial segments.

Gas-fired electricity generation demand in NSW and the ACT

EAPL assumed that against a backdrop of low electricity prices and an apparent excess of base electricity generation capacity in NSW and Victoria, gas-fired power generation would not become competitive until at least 2005. The only project viewed by EAPL as being viable and likely to commence operations within the initial access arrangement period, was the ALISE project (located in Botany) which EAPL assumed would commence operations in 2006. As to total demand for major new power generation and co-generation facilities, EAPL assumed this would increase from 7 PJ per annum in 2005 to 50 PJ per annum by 2014. For smaller (0.5 to 20 MW) embedded generation and co-generation plants EAPL assumed this would utilise up to 3 PJ per annum by 2005.

Servicing demand in Victoria

For this aspect, EAPL assumed the Cooper/Eromanga Basin producers would sell up to 12 PJ per annum into the Victorian market by 2005 as a competitive response to a loss of market share in NSW. EAPL also assumed the north bound flow of gas through the Interconnect into NSW would be low in early years as a result of the entry of the EGP.

Market share

On the issue of market share, EAPL assumed that the commencement of the EGP would result in its market share declining significantly with 20 – 50 per cent of the loads expected to be transported on the EGP previously supplied exclusively by the MSP.[298]

Source of gas supply

EAPL assumed that the depletion of gas supplies in the Cooper/Eromanga Basin and Bass Strait would in the longer term provide the opportunity for gas from both Papua New Guinea and Timor Sea to supply Australia with Moomba becoming the hub for transporting gas into south-eastern Australia.

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[297] EAPL access arrangement information, 5 May 1999, pp. 12-15 and EAPL supplementary access arrangement information, 28 October 1999, pp. 2-10.

[298] EAPL supplementary access arrangement information, 28 October 1999, p. 2.

Conclusion to demand forecasts

In submitting these projections, and in particular the projections for gas throughput on the MSP, EAPL claimed that there was a 'higher degree of uncertainty attached to the demand forecasts for the EAPL system than virtually any other pipeline system in Australia'.[299] This uncertainty, according to EAPL, stemmed not only from end-user demand but also from pipeline and inter-basin competition.

Load factor

Under EAPL's proposed two-part tariff structure, capacity charges were determined by adjusting forecast throughput by an estimated load factor where the load factor was defined as the average daily quantity divided by the peak daily quantity for the system. In the original access arrangement EAPL assumed a load factor of 100 per cent.

2.8.3 Commission's Draft Decision

The Commission reviewed the gas throughput forecasts submitted by EAPL to establish whether the forecasts represented best estimates arrived at on a reasonable basis as required by section 8.2(e) of the Code. In carrying out this review, the Commission evaluated the methodology and assumptions upon which the forecasts were predicated and gave consideration to the level of uncertainty surrounding specific aspects of the forecasts.

In relation to the methodology and assumptions underlying EAPL's forecasts, the Commission concluded that they were appropriate and noted that in forming this view it had given particular weight to ACIL Consulting's overall endorsement of the MSP throughput forecasts contained within the APT offer document, *Buried Treasure*.

On the issue of uncertainty surrounding demand for gas-fired electricity generation and co-generation, the Commission acknowledged that unforeseen delays in the construction and commissioning of large-scale projects had in the past given rise to substantial discrepancies between forecast and achieved volumes. The Commission noted that this trend would be likely continue into the future. Notwithstanding this uncertainty, the Commission considered that the assumptions underlying EAPL's forecasts were reasonable.

Overall, the Commission concluded that on the evidence available, EAPL's forecasts of gas demand in NSW and ACT and the quantities of gas it expected to transport on the MSP satisfied the requirement of section 8.2(e) of the Code. The Commission also accepted the 100 per cent load factor assumed by EAPL.

As a part of its review of forecast volumes, the Commission also explored the alternatives to utilising forecast volumes to derive reference tariffs in circumstances where a service provider faces a loss of market share (and excess capacity) as a result of the entry of another pipeline. To assist in this, the Commission engaged NERA to

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[299] EAPL supplementary access arrangement information, 28 October 1999, p. 4.

consider the implications of five alternative methods for the regulation of tariffs.[300] These alternatives included determining tariffs on the basis of:

- defined capacity;
- deemed volumes (that is the volumes which prevailed prior to the loss of market share);
- forecast volumes;
- forecast volumes and using back end loaded depreciation; and

The fifth alternative identified by NERA was the removal of regulation on tariffs.

In evaluating the first three alternatives, NERA sought to address three fundamental aspects: which party would bear the cost of spare capacity; what incentives are accorded to parties to minimise excess capacity; and which party is in the best position to actually act on the incentives. NERA's findings can be seen in the diagram below where the three alternatives form a continuum, with forecast volumes at one extreme yielding higher tariffs and defined capacity at the other generating lower tariffs.

[300] NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000.

Figure 2.8.3.1: Summary of NERA's findings

High tariffs → **Low tariffs**

	Forecast volumes	**Deemed volumes**	**Defined capacity**
Who is in the best position to encourage efficient utilisation of the pipeline?	Service provider.	Service provider.	Service provider.
Who bears the cost of excess capacity?	Users through tariffs based on cost recovery and lower volumes.	Shared between the service provider and users.	Service provider through tariffs based on capacity.
Incentives to encourage growth and reduce excess capacity.	Limited incentives for the service provider to engage in vigorous competition to expand capacity utilisation. Strong incentives for users.	Incentives for both the service provider and users to encourage greater utilisation of pipeline.	Strong incentives for the service provider to encourage greater utilisation and minimise excess capacity because it is unable to recover the cost of full capacity unless capacity utilised.
Impact on future investment	Investment in capacity likely to occur well in advance or demand because users bear the cost.	Increased risk surrounding investment decisions due to regulatory uncertainty arising from establishing 'deemed' volumes over time.	Investment in capacity unlikely to occur unless the service provider has a reasonable expectation that the pipeline will operate at or near full capacity
Overall assessment	Sub-optimal due to lack of alignment of incentives with actual ability to act.	Sub-optimal for efficient future investment decisions.	Optimal due to closest alignment of incentives with ability to act.

Source: NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. iv.

Essentially, NERA concluded that in terms of efficiency the option which should be adopted is the one that results in the closest alignment of incentives to minimise spare capacity (and to pursue efficiency) with the actual ability to encourage greater utilisation of the pipeline. As can be seen in the diagram above, it is the service provider who is in the best position to minimise spare capacity and it is for this reason that NERA concluded that defined capacity should be used to derive tariffs.

In advocating this approach, NERA observed that by bearing the full cost of excess capacity, the service provider would be accorded the greatest incentive to minimise spare capacity by encouraging greater utilisation of the pipeline and ensuring that the timing and extent of additions to future capacity were optimal.[301] However, NERA cautioned that if defined capacity were to be adopted it would represent a significant

[301] NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. 4.

departure from previous regulatory decisions within Australia and as such some form of transitional adjustment would be appropriate.[302]

Deemed volumes were viewed unfavourably by NERA largely because of the perceived difficulties which would arise in applying the measure over time giving rise to regulatory uncertainty. Such regulatory uncertainty would, according to NERA, weaken incentives over time and increase the riskiness of future investment decisions. As to the use of forecast volumes, NERA concluded that this approach would result in a sub-optimal outcome from an incentive perspective, with users bearing the full cost of excess capacity without having the ability to promote greater utilisation of the pipeline.[303]

The use of forecast volumes combined with back end loaded depreciation was also considered by NERA. It concluded that back end loaded depreciation transfers the burden for paying for excess capacity from users in the current period to future users who (as with current users) would have little ability to actually encourage greater utilisation.[304]

The final alternative considered was the removal of regulated tariffs. NERA cautioned that prior to this occurring it would be necessary to assess the extent to which the pipelines offer substitute services. To the extent that there is any differentiation (for example, transporting from different basins with distinct well-head prices) the incumbent may retain a degree of market power sufficient to set tariffs above costs.[305] This alternative was not considered in the Commission's assessment because decisions relating to the revocation of coverage can only be made by the relevant minister (section 1.24 of the Code).

The Commission considered NERA's report and noted that while the defined capacity approach would in effect overcome the apparent anomaly of tariffs rising as a result of a new entrant, the approach would be a significant departure from the current approach adopted by regulators. The Commission concluded that the forecast volumes approach should be retained but invited further comments from interested parties.

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302 NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. iii.

303 NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. iii.

304 NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. 24.

305 NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios: A report to the ACCC*, October 2000, p. 9.

2.8.4 Submissions in response to the Draft Decision

The PIAC asserted that the Commission's proposal to utilise forecast volumes would in effect mean that residential consumers would pay for the introduction of competition. The PIAC argued that such an outcome would be inappropriate and stated that:

> it makes good business sense for EAPL to pursue full capacity in preference to passing the costs of less capacity on to end-users, particularly residential consumers. [306]

In contrast to the PIAC's position, DEI noted its preference for the use of forecast volumes to pipeline capacity when establishing revenue requirements. DEI asserted that that the use of capacity, as suggested by NERA, would effectively make it impossible for any pipeline to break even at less than full capacity. DEI noted that although the use of defined capacity would provide service providers with an incentive to maximise utilisation (an incentive that DEI argues pipeline owners already have), it would also have a negative impact on investment, deterring even modest investments in capacity. While DEI claimed a preference for forecast volumes over defined capacity, it stressed that the use of forecast volumes could result in detrimental effects in circumstances where there are competing pipelines which in effect could give rise to a 'winner takes all market dynamic'.[307]

EAPL's response to the Draft Decision

EAPL concurred with the Commission's *Draft Decision* to derive tariffs on the basis of forecast volumes rather than capacity. In outlining its position on this issue, EAPL argued that the study carried out by NERA was 'overly simplistic' and did not take into account the commercial reality and the financial burden that would be placed upon the incumbent if the defined capacity approach were to be utilised. EAPL contended:

> the commercial reality is that the need to discount to sell the capacity is likely to place a significant financial burden on the incumbent. This financial burden would be further magnified under the 'defined capacity' approach where the incumbent will only earn its allowed costs if it can sell all its capacity at the regulated rate. The 'defined capacity' approach gives no recognition to the fact that if the pipeline has to discount below the regulated rate, it will not earn the amount which has been accepted as its costs of operating the pipeline. [308]

EAPL concluded that the NERA report fell short of the level of analysis that would be required before any change to the application of the Code were adopted.[309]

2.8.5 Revised access arrangement

Since the release of the Commission's *Draft Decision*, EAPL has submitted two sets of revised gas throughput forecasts. The first of these were submitted with the revised access arrangement in May 2002 and the second following the 18 December 2002 announcement by AGL that it had entered into a portfolio of new supply contracts.

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[306] PIAC submission, 12 February 2001, p. 2.

[307] DEI submission, 9 February 2001, pp. 9-10.

[308] EAPL submission in response to the Draft Decision, 14 March 2001, pp. 31-32.

[309] EAPL submission in response to the Draft Decision, 14 March 2001, p. 32.

Forecasts submitted with the revised access arrangement

The forecasts submitted by EAPL with its revised access arrangement in May 2002 were limited to its projections for aggregate gas throughput forecasts for the MSP over the expected length of the access arrangement period (see Table 2.8.5.1).

Table 2.8.5.1: Forecast gas throughput for the MSP submitted in May 2002 (PJ)

Year Ending 30 June	**2003[(a)]**	**2004**	**2005**	**2006**	**2007**	**2008**
Total MSP Throughput	64.76	88.69	96.70	109.91	125.14	130.39

Source: EAPL access arrangement background information, 3 May 2002, p. 1.
Notes: (a) Nine months of data October 2002-June 2003.

Revised forecasts submitted following AGL gas supply announcement

On 18 December 2002, AGL announced that it had entered into new gas supply contracts and was re-assessing its options for gas supplied from Papua New Guinea.[310] Following this announcement, EAPL advised the Commission that it would be reviewing its forecast volumes, capital expenditure and operating expenditure. A preliminary version of the revised forecast volumes through to 2022 was submitted to the Commission on 7 March 2003. In a letter accompanying the forecasts, EAPL stated that the AGL announcement had brought to the fore the difficulties in estimating the market share of both the MSP and the EGP.[311] According to EAPL, these difficulties along with changes in the likely sources of supply for South East Australia and changes to State and Australian government policies regarding greenhouse gas emissions, made it essential to totally review gas throughput forecasts.[312]

The specific assumptions and methodology utilised by EAPL to estimate its revised forecasts for total gas demand in NSW and ACT and throughput on the MSP are outlined below.[313]

Conventional demand in NSW and ACT

The forecasts for this segment of demand were based largely upon unpublished gas and ethane demand forecasts to 2020 produced by ABARE in March 2003. EAPL then adjusted these forecasts to remove the volumes attributable to ethane and those attributable to the Sithe Smithfield co-generation plant. Actual deliveries of gas into NSW and ACT were then used to rebase the adjusted forecasts to 2001/02.[314] The growth in adjusted forecasts, measured as the change in volumes (PJ), was then applied to the base year through to 2020. For the remaining two years of the forecasting period EAPL assumed a one per cent growth rate.

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310 AGL media Release, *AGL Announces New Gas Supply Portfolio*, 18 December 2002.

311 EAPL letter to the Commission, 7 March 2003.

312 EAPL revised access arrangement information, 7 July 2003, p. 36.

313 EAPL revised access arrangement information, 7 July 2003, pp. 36-39 and volume models submitted to the Commission on 12 May 2003.

314 The Commission notes that in EAPL's revised access arrangement information, EAPL states that the base year is 1999/00, however, based on models sent to the Commission it appears that the base year to which growth rates are then applied is 2001/02.

Gas-fired electricity generation demand in NSW and ACT

Forecasts for this aspect of demand were based on existing demand and assumptions relating to the construction of additional electricity generation in NSW and ACT. Specifically, EAPL has assumed that large scale gas-fired electricity generation will not be viable in NSW or ACT until 2008 with demand thereafter shared between the MSP and the EGP. EAPL has also assumed that co-generation demand will be less than that assumed in the original forecasts submitted in 1999 and has included these forecasts within industrial demand. These assumptions were formed with reference to the NSW Ministry of Energy and Utilities' (MEU) *Statement of System Opportunities*[315] and NEMMCO's 2002 and 2003 *Statement of Opportunities* (SOO). EAPL also utilised actual demand for gas in electricity generation for the period 2001/02 and then applied its projections for growth through to 2022.

Market share

In determining the apportionment of total NSW and ACT demand across the MSP, the EGP and Sydney Gas Company, EAPL had recourse to public statements by the EGP, Sydney Gas Company, MSP shippers, prospective shippers and producers. To establish MSP throughput, EAPL deducted from total NSW and ACT demand the volumes it assumed would be produced and supplied by the Sydney Gas Company and the volumes which it expected to be transported on the EGP.

In deriving projections for the volumes of coal seam methane to be produced and supplied by the Sydney Gas Company, EAPL assumed that the volumes would be 'somewhat less than figures in Sydney Gas' public statements'.[316] For the volumes to be transported on the EGP, EAPL assumed:

- a switching of loads to the EGP resulting from the AGL contract with producers in the Gippsland Basin;
- that conventional demand will be shared between the EGP and the MSP; and
- that gas-fired electricity demand will be shared between the EGP and the MSP.

Total flows on the MSP were then calculated by taking into account EAPL's projections for Victoria bound gas flowing from Moomba through the Interconnect. Interconnect flows are expected to flow in a net physical northbound direction during the access arrangement period although EAPL notes that this will change from season to season depending on market conditions. EAPL has also noted that forecast throughput to all MSP delivery points, other than Wilton, Canberra and Culcairn are the same as those submitted in May 2002.

Source of gas supply

EAPL has assumed in the short to medium term that there will be no supply from either the Timor Sea or Papua New Guinea. Beyond this, EAPL has assumed that northern gas (including coal seam methane from Queensland) will be delivered via Moomba from Queensland.

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315 NSW Ministry of Energy and Utilities, *Statement of System Opportunities*, 2002.

316 EAPL revised access arrangement information, 7 July 2003, p. 38.

Load factor

EAPL has claimed that the proposed load factor is commercially sensitive and thus the actual value adopted has not been made publicly available. Notwithstanding the commercial sensitivity surrounding the actual value, EAPL has submitted that the original load factor of 100 per cent had been affected by the loss of loads to the EGP.[317] The extent that this has affected the load factor on the MSP has been estimated by EAPL with reference to historical data for the peak and loads lost to the EGP.[318] This estimation has then formed the basis for proposed load factor with EAPL assuming a constant load factor over the access arrangement period. The assumption of a constant load factor is consistent with EAPL's assumptions that there will not be 'any significant additions or losses to its load such that the load factor would change materially'.[319]

ACIL Tasman consultancy

Although the resulting forecasts were described by EAPL as being based on the best information available, it noted that it had 'significant reservations about the quality of the forecasts it had been able to develop in the time frame'.[320] Given these reservations, the Commission agreed to EAPL engaging the services of ACIL Tasman to review the methodology utilised by EAPL and its gas throughput forecasts for the MSP in accordance with section 8.2(e) of the Code. A confidential copy of ACIL Tasman's report was submitted to the Commission on 12 May 2003.

ACIL Tasman's examination of conventional demand concluded that while EAPL's assumptions were reasonable, some aspects of the methodology could be further considered. One such aspect was the methodology used to apply ABARE's forecast growth in volumes for conventional demand. ACIL Tasman noted that it was the projected growth rates which should be applied to the base year rather than the projected change in volumes. In addition, ACIL Tasman suggested that a smoother transition in forecasts from 2020 to 2021 could be adopted.[321] ACIL Tasman was also of the view that in the longer term demand for gas within these sectors would mature resulting in lower growth rates than those projected by ABARE and EAPL over the period 2016–2020.[322]

Drawing upon its own modelling for gas-fired electricity generation, ACIL Tasman observed that EAPL's forecasts were similar to its own and concluded that the forecasts were reasonable.[323] However, ACIL Tasman noted that some allowance could be made for additional gas consumption from small-scale co-generation induced by the NSW Greenhouse Abatement Certificate scheme (NGACs).

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317 EAPL revised access arrangement information, 7 July 2003, p. 41.

318 EAPL response to the Commission, 27 June 2003.

319 EAPL response to the Commission, 27 June 2003.

320 EAPL letter to the Commission, 7 March 2003.

321 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 4.

322 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 6.

323 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 11.

In addition, ACIL Tasman noted that the potential for coal seam methane to be used in gas-fired electricity generation in the Hunter Valley region could also be considered in EAPL's longer term forecasts. The analysis undertaken by ACIL Tasman was in reference to NEMMCO's 2002 SOO. Since the completion of this analysis NEMMCO has released its 2003 SOO. ACIL Tasman's preliminary work to incorporate the assumptions made in the 2003 SOO has been provided to the Commission on a confidential basis.[324]

ACIL Tasman also examined the methodology and assumptions underlying EAPL's allocation of demand to the Sydney Gas Company, the EGP and the MSP. ACIL Tasman concluded that the methodology underlying EAPL's forecasts for gas throughput forecasts for both the EGP and the MSP was 'sound'.[325] It concluded that as the forecasts lay within the bounds set by its two modelling scenarios the forecasts flows were reasonable.[326] In relation to EAPL's forecasts for gas produced by the Sydney Gas Company, ACIL Tasman submitted that its own models generated higher supply projections than those incorporated within EAPL's forecasts.[327] Finally, ACIL Tasman noted that the approach used by EAPL to derive forecast flows on the Interconnect, was reasonable given the range of possible outcomes surrounding the source of gas supply.[328]

Notwithstanding its conclusion that EAPL's forecasts were reasonable and represented a 'balance' between the northern and southern gas supplies, ACIL Tasman conceded that:

> While the EAPL forecast may be thought to represent a reasonable 'average' of the possible outcomes, the potential is for the EAPL forecast to materially overestimate flows in the MSP (as compared to ACIL Tasman's southern gas scenario). Alternatively, they may significantly underestimate the MSP flows (as compared to ACIL Tasman's northern gas scenario), at least for the 'upstream' section of the pipeline that might facilitate delivery of gas to Victoria.[329]

Of the four areas which ACIL Tasman submitted could be considered further, EAPL adopted three. Specifically, EAPL has:[330]

- altered its methodology for estimating demand within the conventional sectors by applying ABARE's forecast growth rates to the base year rather than forecast volumes;
- smoothed the path of conventional demand growth from 2020 onward;
- incorporated an allowance for gas used in small co-generation plants; and

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324 ACIL Tasman, *The 2003 NEMMCO SOO – A brief on the implications for NSW gas-fired electricity generation*, 15 August 2003, p. 2.

325 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 26.

326 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 26.

327 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 16.

328 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 28.

329 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 30.

330 EAPL letter to the Commission, 12 May 2003.

- rejected ACIL Tasman's suggestion that some consideration may be given to the potential for Hunter Valley coal seam methane to be used for gas-fired electricity generation.

In rejecting this last aspect, EAPL stated that the lower success rates experienced to date in NSW had led it to conclude that the potential development for coal seam methane in NSW was less than that in the Bowen/Surat basins. The revised forecasts submitted by EAPL following the above adjustments are contained in the table below.

Table 2.8.5.2: Revised forecast gas throughput - submitted May 2003 (PJ)

		Access Arrangement Period				
Year ending 30 June	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Total NSW and ACT demand	118.7	121.3	123.5	126.5	130.1	136.5
Total transported on MSP	95.5	95.4	92.4	93.6	93.2	90.0
Moomba Wilton	77.1	75.8	72.4	72.3	67.6	62.6
Canberra Lateral	6.7	6.9	7.1	7.3	7.5	7.8
Northern Lateral	3.3	3.4	3.5	3.6	3.7	3.8
Wagga Lateral	2.7	2.8	2.9	2.9	3.0	3.0
Griffith Lateral	1.2	1.3	1.3	1.3	1.3	1.4
Interconnect - Receipt	3.0	4.0	5.0	6.0	7.0	7.4
Interconnect - Delivery	1.4	1.2	0.2	0.2	3.0	4.0

Source: EAPL revised access arrangement information, 7 July 2003, p. 40.

2.8.6 Submissions in response to the revised access arrangement

There were no submissions received in response to the gas throughput forecasts submitted in EAPL's May 2002 revised access arrangement. Following the submission of revised throughput forecasts in May 2003 the Commission released an issues paper seeking public comment on the downward revisions. The Commission received two submissions in response from AGL Energy Sales (AGL) and Marketing and TXU.

In its submission, AGL acknowledged the new gas supply arrangements it had entered into and noted that they formed the basis for how it plans to transport gas via the MSP to meet forecast demand in NSW and ACT.[331] AGL stated that it had also entered into contracts with Sydney Gas Company to purchase up to 14.5 PJ per annum over a 10 year period, which would in effect displace some of the Cooper/Eromanga and Bowen/Surat basin gas transported via the MSP and in turn reduce the load factor for gas transported on the MSP. AGL suggested that the Commission consider the impact this change would have on the assumed load factor for gas transported on the MSP.

AGL also stated that in its view the majority of the growth in gas-fired generation over the access arrangement period would be in summer peaking capacity. According to

331 AGL Energy Sales and Marketing letter to the Commission, 13 August 2003.

AGL, this form of growth would not affect EAPL's revenue forecasts because any extra gas required over summer would be unlikely to exceed a shipper's winter based maximum daily quantity. AGL requested that the Commission consider the impact of gas-fired generation on the assumed load factor.

In terms of forecasts beyond the access arrangement period, AGL submitted that the Commission should also consider the potential impact of the source of gas supply upon the transportation of gas via the MSP.

TXU responded to the revised forecasts and ACIL Tasman's review by stating that it was 'not sufficiently familiar with the arrangements to be able to add value to this debate at the detailed level'. Nevertheless, TXU made a number of comments regarding the competitive pressures imposed upon EAPL which TXU contended could clearly be seen by the revisions to volumes. TXU added:

> …the very need for this consultation highlights the issue that the EAPL pipeline ought to be 'uncovered' and not subject to the regulatory oversight currently being imposed.[332]

2.8.7 Commission's considerations

Volume forecasts play a number of roles under the NPV approach, with forecast volumes determining not only the path of tariffs and revenue over time but also the path of economic depreciation. Under EAPL's proposed reference tariff policy, forecast volumes also act as an incentive mechanism in that EAPL retains (bears) all benefits (costs) in circumstances where actual throughput exceeds (falls short of) forecast volumes. This exposure to volume risk in effect provides EAPL with an incentive to surpass forecasts which may be achieved by either encouraging market growth through the access arrangement period or by basing tariffs on conservative estimates of likely throughput. The Commission is acutely aware of the potential for a service provider to understate volume forecasts. It is with this in mind that the Commission has assessed the proposed volume forecasts over the initial access arrangement period with a view to determining whether the forecasts do in fact represent the best estimate arrived at on a reasonable basis (section 8.2(e)).

In utilising the NPV approach EAPL has submitted volume forecasts to 2022 and assumed volumes remain constant at the 2022 level through to 2056. While these forecasts have been submitted to the Commission, the Commission's assessment of whether the forecasts represent best estimates arrived at on a reasonable basis has been restricted to the access arrangement period. For the purposes of modelling in the NPV framework the Commission has adopted EAPL's long term forecasts (that is, from the end of the access arrangement to 2056). The Commission's decision to use these forecasts does not imply that the Commission accepts that the long term forecasts represent best estimates arrived at on a reasonable basis. Rather the decision stems from the recognition that while the NPV model determines a tariff and revenue path through to 2056, this path will change over time as EAPL submits revisions to its access arrangement with respect to forecast operating expenditure, capital expenditure, volumes and WACC parameters. As with each of these aspects, the Commission's focus in assessing an access arrangement is upon the conditions which are expected to

[332] TXU response to EAPL gas forecasts for the MSP, 12 August 2003, p. 1.

prevail over the forthcoming access arrangement period. Accordingly, this *Final Decision* focuses upon the volumes projected to flow through the MSP over the impending access arrangement period.

It should be noted that TXU has claimed that the downward revisions to forecast volumes demonstrate that the MSP should not be the subject of regulation. The Commission notes that the issue as to whether a pipeline should be covered is not within the Commission's discretion. That is, in accordance with section 1.24 of the Code a decision to revoke coverage on a pipeline can only be made by the relevant Minister. In view of the fact that the MSP is currently deemed a covered pipeline, pursuant to section 1.13 of the Code, the Commission has proceeded with its assessment of the proposed access arrangement on this basis.

Before moving on to consider the revised volumes forecasts, the Commission will address the issues raised in response to NERA's evaluation of alternative measures to determine tariffs when an incumbent pipeline faces a loss of market share. An examination of the revised forecasts will then be undertaken with recourse to the relevant provisions of the Code, in particular sections 8.2(e), 8.1 and 2.24.

Alternatives to using forecast volumes to derive tariffs

The Commission's *Draft Decision* explored the alternatives to utilising forecast volumes to derive reference tariffs in circumstances where a service provider faces a loss of market share (and excess capacity) as a result of the entry of another pipeline. The basis for this examination was the apparent anomaly of MSP tariffs rising following the construction of the EGP. The Commission was concerned that the use of forecast volumes to determine tariffs would mean that any forecast loss of market share to the EGP would result in higher regulated tariffs on the MSP than would otherwise be the case. While this outcome would appear contrary to the outcome expected in a competitive market, it is consistent with a market which exhibits natural monopoly characteristics with high sunk costs, relatively high fixed costs and decreasing unit costs. The difficulty this outcome presents is that a fall in forecast volumes and a subsequent increase in transportation tariffs has the potential to exacerbate the loss of market share and in turn result in a self-perpetuating cycle with increasing tariffs resulting in an even greater loss of market share.

This potential outcome was of some concern to the Commission and acted as a catalyst to exploring alternative measures of volumes to use for tariff setting purposes. As a result, NERA was commissioned to consider the implications of five alternative methods for the regulation of tariffs. As outlined earlier, NERA concluded that the use of defined capacity to determine tariffs was the optimal methodology as it resulted in the closest alignment of incentives to minimise spare capacity with the party who is actually able to encourage market growth, that is the service provider.

The Commission recognises that basing tariffs on defined capacity would overcome the apparent anomaly of tariffs rising as a result of the emergence of a new entrant and would ensure that the costs of excess capacity are borne by the service provider and not users. However, the adoption of a defined capacity approach would represent a significant departure from the existing approach adopted by Australian regulators. Although NERA submitted that the use of defined capacity did not appear to have deterred investment in the US, the impact of using such an approach in Australia is unclear.

Both DEI and EAPL submitted that the defined capacity approach would place a significant financial burden on the service provider and have a negative effect on any capacity increasing investment. The Commission acknowledges the comments of DEI and EAPL and recognises that using the current capacity of the mainline would result in a substantial price and revenue shock for EAPL with revenue requirements allocated across volumes which are not expected to eventuate in the short to medium term. In effect, this would result in a movement away from the principles set out in section 8.1 of the Code by failing to provide a stream of revenue that recovers the efficient costs of delivering the reference service over the life of the assets (section 8.1(a)). As a result the use of capacity has the potential to affect both the safe and reliable operation of the pipeline (section 8.1(c)) and investment decisions in the MSP and other pipelines (section 8.1(d)). Therefore, the use of forecast volumes to determine reference tariffs results in a closer alignment with the principles contained in section 8.1 of the Code. Accordingly, the Commission has concluded that the use of forecast volumes to derive tariffs should be retained for the MSP in the initial access arrangement period.

Revised volume forecasts – Preliminary analysis

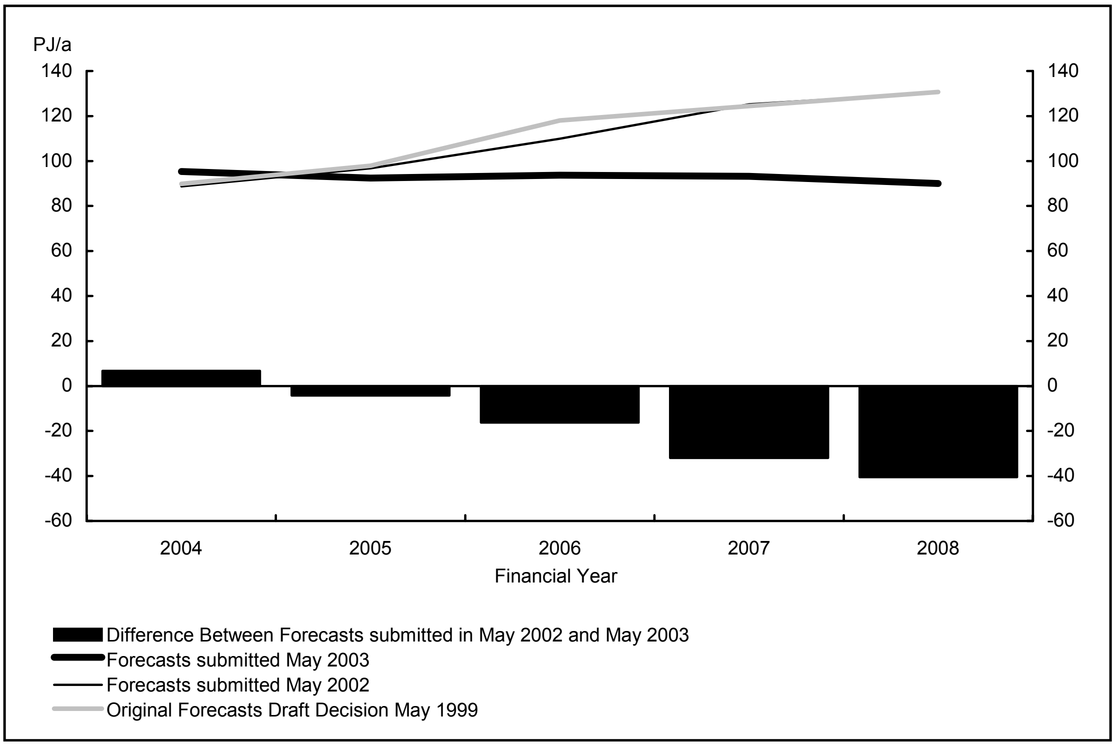
As noted above, EAPL has submitted two sets of revisions to its forecast volume data for the MSP. As indicated in Table 2.8.7.1, the initial revisions in May 2002 reduced forecast demand by an average 1.8 per cent. The most significant decline (of 9 PJ) was expected in 2006. Subsequent revisions in May 2003, which form the forecast volumes to be assessed for the proposed access arrangement, represent a significant reduction from those submitted a year earlier. Table 2.8.7.1 and Figure 2.8.7.1 illustrate the magnitude of the downward revisions between the forecasts submitted in May 2002 and May 2003, which reach 40 PJ by 2007/08.

Table 2.8.7.1: Differences between volume forecasts submitted (PJ)

Year ending 30 June	**2004**	**2005**	**2006**	**2007**	**2008**
Original access arrangement forecasts May 1999	89.9	97.9	118.1	124.4[(a)]	130.7
Revised access arrangement forecasts May 2002	88.7	96.7	109.9	125.1	130.4
Forecasts submitted 12 May 2003	**95.4**	**92.4**	**93.6**	**93.2**	**90.0**
Difference between forecasts submitted in May 2002 and May 2003 (PJ pa)	*6.7*	*-4.3*	*-16.3*	*-32.0*	*-40.4*
Difference between forecasts submitted in May 2002 and May 2003 (%)	*8*	*-4*	*-15*	*-26*	*-31*

Notes: (a) 2007 figures for the initial access arrangement were calculated by the Commission as the average of the 2006 and 2008 figures supplied by EAPL in 1999.

Figure 2.8.7.1: Difference between forecasts submitted in May 2003 and May 2002



The Commission's preliminary analysis of the revised volume forecasts focused on:

- the effect of AGL's announcement upon EAPL's forecasts for the MSP;
- the uncertainty surrounding gas-fired electricity generation; and
- the likely source of long term gas supplies.

AGL announcement

According to AGL's 18 December 2002 announcement, the new gas supply arrangements will supplement and ultimately replace existing contracts with producers in the Cooper/Eromanga Basin (due to expire in 2006) and the Gippsland Basin (due to expire at the end of the decade).[333] Specifically, AGL has contracted to take up to:

- 563 PJ of gas over 2004 – 2013 from the BHP Billiton/Esso Gippsland Basin producers to be supplied into NSW, ACT and Victoria;[334]
- 505 PJ of gas over 2003 – 2016 from the Cooper/Eromanga Basin to be supplied into NSW, ACT and South Australia;[335] and
- 340 PJ of coal seam methane over 2005 – 2020 from Origin Energy's interests in the Bowen/Surat Basin to be supplied into NSW, ACT and South Australia.[336]

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[333] AGL media release, *AGL Announces New Gas Supply Portfolio*, 18 December 2002.

[334] BHP Billiton media release, *BHP Billiton Signs Memorandum of Understanding with AGL*, 18 December 2002.

[335] Santos media release, *Major new gas contracts for the Cooper Basin*, 18 December 2002.

[336] Origin Energy media release, *Major agreements herald a new era in gas supply*, 18 December 2002.

In relation to the transportation of the above, AGL has stated that it will utilise the MSP, the MAPS, the GasNet system and the EGP.[337] It appears that gas from the Gippsland Basin will be delivered into Victoria via the GasNet system and into NSW and ACT via the EGP.[338]

On the information publicly available it is unclear what level of contracted volumes are destined for NSW and ACT and what volumes will be transported to South Australia, Queensland or Victoria. The Commission is also aware that the GTD between AGLWG and EAPL will impact on the transportation of gas under the new arrangements noted above. This deed provides that from 1 January 2007 through to 1 January 2017 EAPL must provide AGL with a grant of transportation reservation to a maximum daily quantity of 162 TJ.[339]

Gas-fired electricity generation

The potential expansion of gas-fired electricity generation in NSW and its implications for growth in the demand for gas within the state has been the source of much speculation for some time. In the *Draft Decision* the Commission concluded that gas-fired electricity generation had been the source of substantial discrepancies between forecast and achieved volumes. The Commission also noted that there was still a substantial degree of uncertainty surrounding this aspect of demand, with planned generation projects either being scaled down or deferred in the face of continued excess capacity and depressed wholesale electricity prices.

The conclusions drawn by the Commission in 2000 are still relevant today, with many combined cycle plant and co-generation projects previously identified as likely to be constructed in the medium term (such as Botany, Kurnell, Marulan and Munmorah) being no closer to commencing operations. Reasons given for the delay of these projects have included the wholesale pricing levels in the electricity market,[340] the abundant and relatively inexpensive supplies of coal available in NSW, surplus generation capacity and the relative price of gas.

Looking ahead, the Commission is aware that four gas-fired power generation projects have been proposed in NSW although the timing on these projects is not yet clear. One of the projects proposed is a gas-fired power station to be built by Narrabri Power Limited (a subsidiary of Eastern Star Gas) using gas from the Coonarah Gas Field.[341] In relying on this source of gas, this project would effectively bypass both the MSP and the EGP. The remaining three projects were identified in NEMMCO's 2003 SOO and were proposed by:

- Wambo Power Ventures, who have proposed two open-cycle gas turbine generators to be located in the Wagga Wagga region. According to the SOO the site has not

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337 AGL media release, *AGL Announces New Gas Supply Portfolio*, 18 December 2002.

338 BHP Billiton media release, *BHP Billiton Signs Memorandum of Understanding with AGL*, 18 December 2002.

339 NCC, *Moomba to Sydney Pipeline System: Revocation Applications Under the National Gas Code, Final Recommendations*, November 2002, p. 67.

340 MEU, *Energy in NSW,* 2000.

341 Eastern Star Gas media release, 14 July 2003.

been purchased and Wambo Power Ventures are yet to obtain licenses and approval, however, it is expected that the turbines will be commissioned by the summer of 2005/06;[342]

- TXU Australia, who have purchased the former Tallawarra power station (located at Lake Illawarra) upon which it intends to develop a gas-fired generator later in the decade. While the site has been acquired, TXU have not yet obtained licenses or approval and is yet to carry out an environmental impact statement.[343] In announcing the purchase of this site, TXU noted that it had signed $5 billion worth of gas contracts with BHP Billiton/Esso and Papua New Guinea producers and stated that some of this 'may be used to supply gas to the proposed generator';[344] and
- Macquarie Generation, who have proposed a combined cycle gas turbine to be located in Tomago (between Nelson Bay and Newcastle). According to the SOO Macquarie Generation are in the process of carrying out an environmental assessment, however, licensing and approval are yet to be obtained.[345]

The delays experienced to date, in addition to the uncertainty surrounding the timing of future projects, demonstrates the uncertainty which has surrounded the development of gas-fired electricity generation in NSW and in turn highlights the difficulties in forecasting this aspect of demand.

Long term sources of gas

The long term source of gas supply for NSW and ACT represents a further source of uncertainty which stems from:

- the availability of reserves in the Cooper/Eromanga Basin and Gippsland Basin and the relative cost of gas from these basins;
- the likely success of coal seam methane; and
- the likely timing of gas from Papua New Guinea or the Timor Sea.

Conclusion

The results of this preliminary analysis demonstrated to the Commission that there was some degree of uncertainty surrounding both the demand and supply of natural gas in NSW and ACT. In view of the uncertainty, the Commission engaged consultants McLennan Magasanik Associates (MMA) to, in the first instance, prepare independent forecasts for the MSP and then provide a critique of the assumptions and methodology upon which EAPL's revised forecasts were predicated.[346] The results of this assessment along with the Commission's overall conclusions are set out below with

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342 NEMMCO, *2003 Statement of Opportunities for the National Electricity Market,* July 2003, p. 3.17

343 NEMMCO, *2003 Statement of Opportunities for the National Electricity Market,* July 2003, p. 3.17-19

344 TXU media release, 27 February 2003.

345 NEMMCO, *2003 Statement of Opportunities for the National Electricity Market,* July 2003, p. 3-17.

346 McLennan Magasanik Associates Pty Ltd, *Report to ACCC: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003.

consideration given initially to EAPL's forecasts for demand for gas in NSW and ACT followed by an examination of the allocation of demand across the MSP, the EGP and Sydney Gas Company.

Revised volume forecasts – Further analysis

Conventional demand in NSW and ACT

The independent forecasts prepared by MMA for conventional demand confirm that EAPL's forecasts compare reasonably, although MMA noted that there were some differences arising from EAPL's correction of the base year. Specifically, MMA observed that the base year used by EAPL may understate actual NSW and ACT market demand in 2001/02. MMA submitted that based on reported and estimated supplies by AGL, Country Energy, ActewAGL and the EGP it appeared that actual demand in NSW and ACT was 1-3 PJ higher than that estimated by EAPL. A further area of concern for MMA was the use of a base year which had included an unseasonably warm winter. MMA estimated that once this aspect is taken into account the base year may increase by 1-2 PJ. Overall MMA concluded that if the difference of up to 4 PJ were reconciled then the two forecasts would be reasonably similar.[347]

EAPL was provided an opportunity to respond to the issues raised in the MMA report and submitted a confidential response to the Commission.[348] The Commission also received additional information from MMA.[349]

The Commission has examined the arguments put forth by EAPL regarding the base year and the conclusions reached by MMA. In relation to the apparent understatement of actual flows in 2001/02 the Commission notes that given the methodology employed by EAPL (that is, using actual metered deliveries for the MSP) then any underestimation of actual flows would have been a result of an underestimation of throughput on the EGP. If this underestimation is attributed to the EGP and the base year increased, then the overall impact on flows forecast to be transported on the MSP is on average equal to 150 TJ per annum over the access arrangement period. While 150 TJ per annum may appear insignificant, the Commission considers that to arrive at a best estimate, as required by section 8.2(e) of the Code, aspects such as these must be addressed. Accordingly, the Commission has specified an amendment that requires an adjustment in accordance with section 8.2(e)) to the volume forecasts to account for the underestimation of the base year.

The Commission is aware that the use of a low base year due to an unseasonably warm winter may result in an underestimation of total demand over time. The Commission has considered the approach employed by both EAPL and MMA to estimate the effect of the warm winter and recognises that there is the potential for some divergence in estimates such as these. On balance, the Commission considers that a 360 TJ adjustment should be made to the base year to reflect the unseasonably warm winter.

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347 MMA, *Report to ACCC: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003, p. iii.

348 EAPL letter to the Commission, 14 July 2003.

349 MMA, *Comments on the EAPL response to MMA forecasts for throughput on the Moomba to Sydney Pipeline*, August 2003.

The fact that those segments of demand affected by the unseasonably warm weather are serviced by AGL appears to suggest that the volumes should be attributed to the MSP. While 360 TJ may appear insignificant, the Commission notes that to derive a best estimate this aspect should be taken into account. Accordingly, the amendment set out below requires an adjustment to the base year volumes of 360 TJ to be allocated to the MSP.

The Commission considers that an overall adjustment to the base year for conventional NSW and ACT demand, (which equates to an average additional 540 TJ per annum for the MSP over the access arrangement period) is consistent with section 8.2(e) of the Code and the reference tariff principles set out in section 8.1. In particular, the Commission notes that the use of a better estimate of the base year will result in reference tariffs which are efficient in accordance with section 8.1(e). Furthermore, the Commission considers that the use of a better estimate replicates the outcome of a competitive market (section 8.1(b)) and provides EAPL with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service (section 8.1(a)). In addition, the use of the best estimate should ensure the continued safe and reliable operation of the pipeline (section 8.1(c)) and prevent any distortion of investment decisions for the MSP and upstream and downstream industries (section 8.1(d)). Finally, the use of the best estimate should maintain incentives to develop the market for the reference service (section 8.1(f)).

Adjusting the base year volumes yields the following forecasts over the access arrangement period.

Table 2.8.7.2: Forecast volumes with base year adjustment (PJ)

Year ending 30 June	**2004**	**2005**	**2006**	**2007**	**2008**
Total NSW and ACT demand	123.7	126.0	129.0	132.8	139.2
Total MSP throughput[(a)]	95.8	92.9	94.2	93.8	90.6

Source: Commission's modelling
Notes: (a) Includes southbound flows on the Interconnect

Amendment FDA 10

In order for EAPL's access arrangement for the MSP to be approved, EAPL must adopt the total MSP throughput forecasts contained in Table 2.8.7.2 of this *Final Decision*.

Gas-fired electricity generation demand in NSW and ACT

As set out above, the Commission is aware of the uncertainty which has surrounded the development of gas-fired electricity generation in NSW to date and the difficulties experienced in forecasting this aspect of demand. The difficulties of forecasting have not diminished over time and in fact appear to have been further complicated by policies introduced by both the NSW[350] and Australian[351] Governments to reduce greenhouse gas emissions and encourage the use of alternative fuels (including gas). The likely effect of state and Australian government policies have been modelled by numerous parties including ABARE, ACIL Tasman and MMA. The conclusions reached by each of these forecasters are set out briefly below.

ABARE has examined the likely effect of the New South Wales Greenhouse Abatement Certificate scheme by modelling gas-fired electricity generation with the scheme and without the scheme.[352] The results of this modelling appear to suggest that with the scheme in operation gas-fired electricity generation will grow rapidly over the period 2003/04 to 2007/08 before plateauing around 2009/10 at around 25 PJ.[353] On average over the period 2000/01 to 2019/20, ABARE expects gas-fired generation to grow by 8.2 per cent per annum. When the scheme is excluded from the analysis ABARE's results suggest that gas-fired electricity generation will grow from 5.8 PJ in 2000/01 to 11.1 PJ in 2005/06 and up to 21 PJ by 2019/20. This represents an average growth rate over the period of seven per cent. As a result, ABARE considers that the NGAC scheme will be likely to pull forward gas-fired electricity generation developments in NSW.

In its review of EAPL's gas forecasts, ACIL Tasman also commented on the likely effect of the NSW Government's greenhouse gas emission policy. According to ACIL Tasman, the NGACs is unlikely to be a major influence in the development of gas-fired electricity generation and large scale co-generation within NSW given the tradability of NGACs and the ability for NGACs to be created outside the state.[354] ACIL Tasman noted that these features combined with existing and more commercially viable gas-fired generation projects in Queensland, South Australia and Victoria, meant that sufficient NGACs were more likely to be created beyond the borders of NSW. This conclusion has resulted in relatively stable projections for demand arising from gas-fired electricity generation estimated by ACIL Tasman of approximately 10 PJ per annum through to 2008. Beyond this ACIL Tasman projects a rapid increase reaching approximately 63 PJ per annum by 2023.[355]

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350 NSW Electricity Retailer Greenhouse Benchmark policy, which requires licensed electricity retailers to comply with greenhouse gas reduction. The scheme is enforced by charging retailers which have excess emissions a penalty for each excess tonne of CO_2 equivalent emission above their benchmark target. The benchmark target is set as a 5 per cent reduction in per person greenhouse gas emissions from 1989/90 by 2007 which equates to a per person target of 7.27 tonnes of carbon dioxide equivalent CO_2-e. These targets may be met by either reducing the greenhouse gas intensity of electricity consumed ie. by changing fuel types; by improving the energy efficiency of their customers; and/or purchasing carbon sequestration credits. A system of emission abatement certificates

351 The Mandatory Renewable Energy Target is designed to develop the renewable energy industry and reduce greenhouse gas emissions

352 ABARE, *Australian Energy: National and state projections to 2019-20*, June 2003, p. 44.

353 ABARE, *Australian Energy: National and state projections to 2019-20*, June 2003, p. 44.

354 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 10.

355 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 11.

In contrast, MMA views the effect of the NGACs more favourably.[356] Specifically, MMA considers that the NGACs will be the principal driver of gas-fired electricity generation development in NSW over the coming decade. Although noting that the location and timing of new gas-fired power generation in NSW is highly uncertain and projects are largely interchangeable, MMA identified the following projects as being likely to be developed over the remainder of the decade:

- a co-generation plant at Botany owned by Amcor which is likely to commence operations around 2007/08;[357]
- a combined cycle plant at Tallawarra (Lake Illawarra), commencing operations around 2008;
- a co-generation plant at Kurnell commencing operations from 2009/10; and
- a co-generation plant at Port Kembla (fuelled by a combination of natural and coke-oven gas) commencing operations from 2011.

With regard to the first two projects, MMA has stated that these are expected to be largely driven by the NGACs and that subsequent co-generation options will become viable as either energy prices increase or further gas-fired emission abatement is required. Overall, MMA concluded that gas-fired electricity generation will increase from about 10 PJ in 2000/01 (excluding generation at Appin/Tower) to 26 PJ by 2007/08 and on to 70 PJ by 2011/12.

Upon examination of each of these forecasts, it is clear that there is no apparent current consensus on the effect the NSW Government's greenhouse gas abatement policy on the construction of gas-fired electricity generation and co-generation in NSW at least in the short to medium term. Although, there appears to be some consensus that demand from this aspect will in the longer term reach around 60-70 PJ per annum.

In terms of overall electricity generation requirements in NSW and ACT, NEMMCO's latest SOO appears to suggest that while electricity generation reserves for winter in NSW will be adequate until 2011, the rapid growth in demand over the summer period in NSW has effectively brought forward the need for investment in this area to approximately 2005/06.[358] These projections are based on a conservative assessment of Queensland, NSW, Victoria and South Australia concurrently being exposed to similar extreme weather patterns. The Commission notes while these projections suggest the need for summer peaking capacity by 2005/06, it is unclear whether such shortages would translate into gas-fired electricity generation. Adding to this uncertainty is the status of the projects identified in the SOO, and the time it would take for these projects to commence operations.

In reference to this information the Commission has considered EAPL's forecasts for demand arising from gas-fired electricity generation. As set out previously, EAPL has

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356 MMA, *Report to ACCC: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003, p. 13.

357 MMA, *Comments on the EAPL response to MMA forecasts for throughput on the Moomba to Sydney Pipeline*, August 2003, p. 13.

358 NEMMCO, *2003 Statement of Opportunities for the National Electricity Market,* July 2003, p. 82.

produced forecasts for demand arising from gas-fired electricity generation having recourse to the MEU's *Statement of System Opportunities* and NEMMCO's 2002 SOO. According to EAPL's projections, major gas-fired electricity generation and co-generation will not be viable until after the access arrangement period, although some co-generation is accounted for within the period. Beyond the access arrangement period, EAPL expects the Tallawarra project will be the first to be commissioned. EAPL has assumed this plant will be serviced by the EGP.

While EAPL's specific forecasts for this aspect of demand have not been made publicly available, the Commission notes that EAPL's forecasts lie within the range established by the independent forecasting undertaken by ABARE, ACIL Tasman and MMA. This suggests that the forecasts over the access arrangement period are reasonable. MMA's report to the Commission noted that while it was unclear as to whether the forecasts represent 'best estimates', as required by section 8.2(e) of the Code, the forecasts appeared plausible and reasonable.[359] Similarly, ACIL Tasman's review of EAPL's informal modelling approach concluded that when compared with its own models EAPL's gas-fired electricity generation forecasts are reasonable.[360] In view of these conclusions and recognising the uncertainty surrounding this aspect of demand, the Commission is satisfied that EAPL's forecasts for gas-fired electricity generation demand in NSW and ACT over the initial access arrangement period represent best estimates arrived at on a reasonable basis (section 8.2(e)).

Supply

Following the construction of both the Interconnect and the EGP and the development of coal seam methane by the Sydney Gas Company, the sources of gas to meet demand in NSW and ACT have expanded such that the Sydney and ACT markets can now be supplied from:

- the Cooper/Eromanga Basin via the MSP;
- the Gippsland Basin via the EGP;
- the Gippsland Basin via the Interconnect; and
- Camden via the AGL network.

The number of sources which can currently supply the NSW and ACT markets provides a further source of uncertainty when forecasting that share of the market which will be supplied by the MSP. The difficulty is exacerbated by the potential for gas from Papua New Guinea, the Timor Sea and the Bowen/Surat Basin to flow into south eastern Australia via the MSP or alternatively for greater volumes of gas from the Gippsland and Otway Basins to flow north into NSW and ACT via either the EGP or the Interconnect.

For the purposes of the current analysis the Commission has focused only on the supply alternatives which will be available over the initial access arrangement period. It is

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[359] MMA, *Report to ACCC: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003, p. 14.

[360] ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 11.

within this framework that the Commission has assessed the allocation method employed by EAPL to determine forecast volumes on the MSP over the access arrangement period.

As mentioned previously, EAPL calculated forecast volumes on the MSP by deducting from total NSW and ACT demand the volumes it assumed would be produced and supplied by the Sydney Gas Company and those volumes which would be transported on the EGP. Projections for southbound flows on the Interconnect were also deducted from total NSW and ACT demand. Each of these aspects are examined below.

Sydney Gas Company

In 2002/03 AGL entered into two 10 year contracts with the Sydney Gas Company to supply up to 14.5 PJ per annum of coal seam methane directly into AGL's distribution system.[361] Recent statements in the media suggest that to fulfil these contracts the Sydney Gas Company will need to develop an additional 100 gas wells.[362] According to the Sydney Gas Company, this development will be completed by the end of 2003.

MMA has informed the Commission that it considers this timetable for development to be optimistic, although it does consider there to be scope for the 14.5 PJ per annum to be achieved over the next decade. In contrast, EAPL's forecasts appear to substantially underestimate the potential future market share of Sydney Gas Company given the contracts in place with AGL. This was noted by ACIL Tasman, who advised that it had forecast higher volumes to be supplied by the Sydney Gas Company than those projected by EAPL.[363] Nevertheless, EAPL has remained steadfast in its view that lower success rates experienced in NSW to date have led it to conclude that the potential development for coal seam methane in NSW was less than in the Bowen/Surat basins.

The Commission is aware that EAPL's forecasts for gas to be supplied by the Sydney Gas Company may appear to be conservative given the contracts in place with AGL. However, the Commission understands that there is some uncertainty surrounding the time it will take to develop the 100 gas wells and for production to be increased up to the 14.5 PJ per annum. Accordingly, the Commission is satisfied that this aspect of EAPL's forecast is reasonable.

Eastern Gas Pipeline

EAPL has estimated the volumes it expects the EGP to transport by making an assumption about the EGP's foundation customer load and estimating volume growth based on:

- a sharing of the growth in conventional demand between the EGP and the MSP;
- that the gas-fired electricity generation plant at Tallawarra being serviced by the EGP, after which growth in gas-fired electricity generation will be shared between the EGP and the MSP; and

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361 Sydney Gas Company, *Mad about Methane,* March 2003, p. 4.

362 The Australian Financial Review, *Investors warm to Sydney Gas raising,* 25 August 2003, p. 17.

363 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney Pipeline,* May 2003, p. 16.

- a switching of loads to the EGP resulting from the AGL contract with producers in the Gippsland Basin.

The allocation method employed by EAPL when apportioning growth in conventional demand and gas-fired electricity demand between the EGP and the MSP has been provided to the Commission and MMA on a confidential basis.[364] The Commission has considered the methodology and the assumptions upon which they are predicated and is satisfied that the allocation method employed by EAPL for the access arrangement period is reasonable.

In relation to the Tallawarra plant, the Commission notes that public statements made by TXU following its purchase of the site appear to confirm EAPL's assumption that it will be serviced by the EGP.[365]

With regard to the EAPL's assumptions of AGL loads switching to the EGP, MMA has informed the Commission that there is a potential for double counting because this factor is not necessarily independent of the assumptions made regarding the allocation of growth in conventional and gas-fired electricity generation demand.[366] Nevertheless, MMA noted that it accepted that AGL would supply some gas through the EGP and that the quantum supplied may be as proposed by EAPL. The Commission has considered the arguments and is prepared to accept that there is no double counting contained within the forecasts.[367] Accordingly, the Commission considers that overall the assumptions made by EAPL when apportioning demand to the EGP are reasonable and form a reasonable basis upon which estimates can be made (section 8.2(e)).

The Commission notes that estimates of EGP volumes must be adjusted in light of its previous conclusions regarding the potential underestimation of EGP loads for the 2001/02 base year. To determine whether these adjusted estimates are in fact plausible and reasonable, the Commission has compared the adjusted projections with those produced by MMA and ACIL Tasman. When compared to ACIL Tasman's forecasts, EAPL's projections appear to underestimate the EGP volumes by an average 8 PJ per annum over the initial access arrangement period. Conversely, when compared to MMA's forecasts EAPL's projections appear to overestimate the loads by an average 4 PJ per annum. As EAPL's forecasts lie within the range set by the consultants, the

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364 ACIL Tasman, *Review of EAPL gas forecasts for the Moomba-Sydney pipeline*, May 2003, Confidential version, pp. 12-26.

365 TXU media release, 27 February 2003. When announcing the purchase TXU stated that it had 'signed $5 billion worth of gas purchase agreements, some of which may be used to supply gas to the proposed generator'. These agreements included agreements to purchase 860 PJ of gas from the Gippsland Basin from 2005 (TXU media release, 13 December 2002), 380 PJ of gas from Otway Basin from 2006 (TXU media release, 15 August 2002) and a conditional agreement to purchase gas from Papua New Guinea from 2007 (TXU media release, 13 December 2002). Given the limited likelihood of gas flowing from Papua New Guinea within this period, it would appear that the likely source of gas is either the Gippsland Basin or Otway Basin. Given the proximity of the EGP to Tallawarra it appears reasonable for EAPL to assume that gas flowing north from either the Gippsland Basin or Otway Basin will flow via the EGP.

366 MMA, *Report to ACCC: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003, pp. 34-35.

367 EAPL confidential letter to the Commission, 14 July 2003, p. 17.

Commission considers EAPL's forecasts to be reasonable. Accordingly, the Commission is satisfied with EAPL's forecasts for the allocation of demand to the EGP.

Moomba to Sydney Pipeline

Using EAPL's allocation methodology, the share of NSW and ACT demand to be supplied via the MSP is essentially the residual after establishing forecasts for the EGP and the Sydney Gas Company. The actual volumes EAPL expects to supply to the NSW and ACT markets over the access arrangement period are set out in Table 2.8.7.3.

While the Commission is satisfied that the overall methodology employed by EAPL when apportioning demand to the Sydney Gas Company and the EGP is reasonable, some adjustment to the NSW and ACT demand forecasts is required to reflect the Commission's previous conclusions regarding the 540 TJ underestimation of the loads to be transported on the MSP (as a result of an underestimation of the base year). The Commission's revised forecasts for the MSP which account for changes in the base year are also set out in Table 2.8.7.3.

Table 2.8.7.3: EAPL's forecasts and the Commission's revised forecasts (PJ)

Year ending 30 June		**Access Arrangement Period**				
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
EAPL's proposed forecasts						
Total NSW and ACT demand	118.7	121.3	123.5	126.5	130.1	136.5
NSW and ACT demand supplied via the MSP[(a)]	94.1	94.2	92.2	93.4	90.2	85.9
Commission's revised forecasts						
Total NSW and ACT demand	**121.1**	**123.7**	**126.0**	**129.0**	**132.8**	**139.2**
NSW and ACT demand supplied via the MSP[(a)]	**94.5**	**94.6**	**92.7**	**94.0**	**90.8**	**86.6**

Source: EAPL, revised access arrangement information, July 2003, p. 40. and Commission modelling.
Notes: (a) Excludes southbound flows on the Interconnect

To determine whether EAPL's estimates adjusted for the base year are plausible and reasonable, the Commission compared EAPL's projections (including the 2.36 PJ adjustment) with those produced by MMA and ACIL Tasman. When compared to ACIL Tasman's forecasts, EAPL's projections appear to overestimate the loads to be transported via the MSP by an average 16.6 PJ per annum over the access arrangement period. Conversely, when compared to MMA's forecasts EAPL's projections appear to underestimate the loads by an average 4.6 PJ per annum over the access arrangement period. While this appears to be a significant range, the Commission notes that differences across the various forecasts primarily stems from differences in assumptions regarding the development of gas-fired electricity generation and the success of coal seam methane. As EAPL's forecasts (adjusted to include the 2.36 PJ in the base year) over the access arrangement period lie within the range set by ACIL

Tasman and MMA, the Commission is satisfied that overall the adjusted volume forecasts represent the best estimates arrived at on a reasonable basis (section 8.2(e)).

While the preceding analysis has focused upon meeting demand within NSW and ACT, the Interconnect also enables gas from the Cooper/Eromanga Basin to flow south to meet demand in Victoria. According to EAPL, southbound flows on the Interconnect are projected to fall over the period 2003-2006 to approximately 0.2 PJ per annum before recovering to 4 PJ per annum by 2008. Overall, the Commission is satisfied that these forecasts are reasonable and represent best estimates (section 8.2(e)).

Revised volume forecasts – Commission's conclusions

The Commission is cognisant of the difficulties in forecasting both natural gas consumption and the source of natural gas supply in NSW and ACT and recognises that these difficulties are likely to continue for some time.

Notwithstanding this uncertainty, the information currently before the Commission appears to suggest that if the forecasts for volumes to be transported on the MSP are adjusted by 540 TJ over the access arrangement period (as required by Amendment FDA 10) then the adjusted volume forecasts will represent the best estimate arrived at on a reasonable basis. Moreover, the conclusions reached by ACIL Tasman and MMA appear to suggest that, apart from the issue surrounding the correction of the base year and differences in assumptions regarding the timing of gas-fired electricity generation, the overall methodology and assumptions adopted by EAPL are reasonable. The Commission is therefore of the view that EAPL's forecasts for natural gas consumption in NSW and ACT and the quantities of gas it expects to transport on the MSP, once the correction to the base year is taken into account, satisfies the requirement of section 8.2(e) of the Code.

The Commission reiterates that the use of forecast volumes is an integral part of the proposed incentive mechanism where EAPL bears the risk of realised volumes being different to forecasts. If actual volumes exceed forecasts, EAPL retains the additional revenue. Conversely, if volumes are less than forecast, EAPL will bear the loss.[368] The Commission considers that where volume forecasts can be classified as the best estimate arrived at on a reasonable basis then the incorporation of such an incentive mechanism will be consistent with the principles contained in section 8 of the Code. In particular, the Commission considers that the use of forecast volumes will provide EAPL with an incentive to promote growth in gas volumes and the market as a whole in accordance with section 8.1(f) and section 8.46(a).

Although the Commission recognises the benefits of this incentive mechanism it also has some concerns that the proposed mechanism does not provide for any sharing of benefits with users in the access arrangement period the event that demand is substantially greater than expected. While there is limited likelihood of any large scale increase in volumes occurring over the initial access arrangement period, the Commission notes that in the future where there is a greater likelihood of such an event

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[368] The Commission does, however, note that EAPL may, pursuant to section 2.28 of the Code submit proposed revisions to the access arrangement at any time including following falls in volumes.

occurring during the access arrangement period (for example, gas-fired electricity generation commencing operations, northern gas flowing to south eastern Australia via the MSP) and where such events are not accounted for within volume projections, then it may consider requiring that these events be defined as trigger events pursuant to section 3.17(b)(ii) of the Code. While the details of how such a trigger mechanism would operate have not yet been determined the Commission notes that such a mechanism would most likely involve the sharing between users and EAPL (based on a specified percentage) of any additional benefits derived from volumes exceeding a pre-determined threshold.

Commission's consideration of the load factor

Load factors describe the percentage of contracted capacity that is actually shipped along the pipeline. The Commission recognises that the value ascribed to the load factor can play a significant role in determining the revenue derived through capacity reservations. The Commission is also aware that the revision in load factors from 100 per cent in the *Draft Decision* to the value currently proposed represents a significant shift from EAPL's original submission. However, the Commission recognises that the entry of the EGP and the resultant loss of high load customers would have resulted in a lower load factor on the MSP.

To determine whether the load factor assumed by EAPL represents the best estimate arrived at on a reasonable basis, as required by section 8.2(e), the Commission has examined the actual daily average and peak day throughput data for the MSP.[369] Based on this historical data (in particular the data for the Wilton delivery point), the value adopted by EAPL appears to be reasonable. The Commission notes EAPL's comments that it does not anticipate any significant shifts in load during the initial access arrangement period. Under such circumstances the use of an historic estimate would appear to represent the best estimate of the load factor to prevail over the access arrangement period.

However, EAPL's assumption that there will be no significant shift in loads over the period contrasts with the position adopted by AGL. The difference between EAPL's and AGL's position stems primarily from differences in the assumptions regarding the market share Sydney Gas Company is likely to attain and the potential for gas-fired electricity generation used to meet summer peaking capacity during the access arrangement period. Given the inextricable link between the assumptions underpinning the load factor and assumptions upon which volume forecasts are predicated, it is clear that for consistency if the Commission were to take into account the effect of these differences upon the load factor it would also have to require adjustments to the overall throughput forecasts.

As set out previously, the Commission recognises that EAPL's assumptions regarding the success of Sydney Gas Company appear relatively conservative. Notwithstanding this, the Commission concluded that the forecasts were reasonable. The Commission also concluded that the forecasts for gas-fired electricity generation proposed by EAPL were reasonable. Given that the assumptions which underpin EAPL's forecast volumes

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369 EAPL revised access arrangement information, 7 July 2003, p. 35.

are consistent with the assumptions underlying the proposed load factor, the Commission concludes the overall the proposed load factor represents the best estimate arrived at on a reasonable basis (section 8.2(e)).

2.9 Forecast revenue and tariff path

Section 2.1 of this *Final Decision* evaluated the reference tariff methodology proposed by EAPL in its revised access arrangement. As foreshadowed in that section, EAPL has proposed the NPV approach to determine its total revenue over the access arrangement period, which is consistent with sections 8.4 and 8.5A of the Code. Under this approach, the X factor represents a smoothing mechanism which ensures that the present value of forecast revenue equates with the present value of costs (including a return on assets, depreciation, tax, and non capital costs) over the remaining life of the asset. That is the NPV of the pipeline is equal to zero. Within this framework, there exist a large number of combinations of X factors and initial starting tariffs within a certain range that result in a NPV of zero.

In any one access arrangement period total revenue represents an exogenous factor which is calculated by multiplying a pre-determined tariff by forecast volumes. That is:

$$\text{Total revenue} = \text{tariffs} \times \text{forecast volumes}$$

This determination of revenue differs from the cost of service approach in which total revenue in each period is simply the sum of the return on assets, depreciation and non capital costs.

Under the NPV approach if the chosen tariff path leads to a situation where forecast total revenue and costs do not correspond within the initial access arrangement period, then economic depreciation acts as a residual or balancing factor. Economic depreciation is then subtracted (in the case of an over recovery of the return on assets, non capital costs, net taxes and new facilities investment) or added (in the case of an under recovery of costs) to the ICB to determine the residual value of the capital base at the end of the access arrangement period. Based on the value of this residual capital base and revised forecasts for costs and volumes, the tariff path over the remaining life of the asset is re-calculated at each subsequent access arrangement period.

Accordingly, under the NPV approach the determination of total revenue is inextricably linked to the decision on the form of the tariff path. It is for this reason that revenues and tariffs are dealt with concurrently in this chapter. The first component of this chapter evaluates the tariffs and tariff path proposed by EAPL, including issues such as backhaul rates and the proposed CPI-X mechanism, and the second half of this section assesses the resulting total revenue over the initial access arrangement period.

2.9.1 Tariffs and tariff path

2.9.1.1 Code requirements

Section 8.3 of the Code states that the manner in which a reference tariff may vary within an access arrangement period through the implementation of a reference tariff policy is within the discretion of the service provider. This is subject to the regulator being satisfied that the reference tariff policy is consistent with section 8.1 and 8.3A of the Code.

The reference tariff policy may specify that reference tariffs vary within an access arrangement period through the adoption of: a cost of service approach; a price path approach; a reference tariff formula approach; a trigger event adjustment approach or any variation or combination of these approaches (sections 8.3(a) – (e)).

Section 10.8 of the Code defines 'price path approach' as:

> a reference tariff variation method whereby reference tariffs are determined in advance for the access arrangement period to follow a path or paths over time forecast to deliver a revenue stream, with that price path or paths not being adjusted to account for subsequent events until the commencement of the next access arrangement period.

Section 8.3A of the Code states that reference tariffs may only vary within an access arrangement period through the implementation of the 'approved reference tariff variation method' as provided for in sections 8.3B - 8.3H, as follows:

- Section 8.3B states that if a specified event occurs or the service provider wishes to vary the reference tariff in accordance with the approved reference tariff policy, then the service provider must notify the relevant regulator.
- Section 8.3C requires that the service provider's notice must specify the service provider's proposed variations to the reference tariff and the proposed effective date, and must provide an explanation of how the variations to the reference tariff are consistent with the approved reference tariff variation method.
- Section 8.3D states that the reference tariff will be varied automatically from the later of:
- the date specified in the notice provided to the regulator; and
- the date implied from the reference tariff policy approved by the regulator; or if the reference tariff policy does not specify a minimum notice period, 35 days after the date of the notice provided by the service provider under section 8.3B.
- Section 8.3E provides that the relevant regulator may by notice to the service provider before the variation is due, disallow a variation of a reference tariff if it is inconsistent or not permitted under the approved reference tariff variation method. The regulator may specify a variation that is consistent with the reference tariff variation method.
- Section 8.3F requires that the regulator must publish its reasons for allowing or disallowing a variation of a reference tariff, or specifying any complying variation.
- Section 8.3G states that if a specified event occurs and the service provider does not provide a notice to the regulator, then the regulator may itself vary the reference tariff concerned under the provisions of the approved access arrangement.

- Section 8.3H specifies that the regulator may grant extensions to any time period on application of the service provider, or extend the time period that applies under section 8.3G.

2.9.1.2 Original access arrangement

In its original access arrangement, EAPL proposed to offer a range of tariffs for different classes of service. Specifically, it proposed to offer two types of reference service (firm transportation service and small take-off point service) for both the mainline and lateral pipelines. These reference services incorporated forward-haul tariffs as well as a backhaul transportation rate for gas flowing in the opposite direction of the main flow of gas. This backhaul rate was equal to 50 per cent of the capacity charge on the relevant segment of the pipeline. Non-reference services offered were three types of rebatable services and a negotiable service.

EAPL initially proposed the adoption of a price path approach to establishing tariffs through the access arrangement period. Specifically, EAPL proposed that mainline tariffs would change over the access arrangement period through a CPI-X adjustment mechanism, which is characterised by a positive X factor of 1.25 per cent set at the start of the access arrangement period. The tariff for the initial year would be based on the existing published firm service tariff.

With regard to regional laterals, EAPL proposed a reference tariff formula which differed substantially to that proposed for the mainline. Specifically, for each year in the access arrangement period, the base tariff would be adjusted in accordance with the change in the CPI with reference to the CPI for the year 2000. EAPL also proposed a minimum distance for lateral tariffs, whereby laterals tariffs would only apply for the first 100 km, after which the mainline tariffs would be levied.

2.9.1.3 Commission's Draft Decision

Tariffs and price path approach

The level of proposed transportation charges was one of the most common concerns expressed by interested parties in submissions to the *Draft Decision*.[370] However, the Commission noted that as a result of its proposed amendments, the price of transportation would fall for most customers. For example, by incorporating the proposed amendments, an indicative average tariff for the Moomba to Wilton pipeline would be $0.47 compared to $0.69 initially proposed by EAPL.

The Commission commented on the proposal by EAPL to use current published tariffs as the base for the price path through the initial access arrangement period. The Commission considered that this application of published tariffs would significantly over recover total costs in the initial years of the access arrangement period when combined with the proposed amendments. Accordingly, the Commission proposed that the reference point should be the cost of providing reference services rather than the published tariffs.

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370 For example, Santos submission 29 July 1999 and Incitec submission, 18 August 1999.

In its original access arrangement EAPL proposed to adjust mainline tariffs in accordance with the following escalation equation:

$$(CPI_n/CPI_{n-1}) - X$$

However, the Commission considered that the following price path formula was more appropriate:

$$(CPI_n/CPI_{n-1}).(1 - X)$$

The Commission viewed this formula as more appropriate as it accounts for the compounding effect of the previous year's escalation. Consequently, an amendment was proposed in the *Draft Decision*.

As noted previously, EAPL proposed an X factor of 1.25 per cent which had the effect that tariffs were to decrease in real terms during the course of the initial access arrangement period. The Commission supported the approach proposed by EAPL in this regard.

Backhaul tariffs

In its submission on behalf of Incitec, NERA expressed concern with the backhaul rate proposed by EAPL. Incitec argued that apart from administrative costs there were no direct costs associated with backhaul.[371] In its consideration of this issue the Commission noted that backhaul was applicable to the Young to Culcairn pipeline, where the predominant flow of gas on different occasions may be either north or south. Under these circumstances, it was considered that a rate of 50 per cent of the capacity charge, as proposed by EAPL may be appropriate. The Commission, however, noted that a 50 per cent charge may not be appropriate in other situations, and invited additional comments from interested parties on this issue.

STP tariff

EAPL stated that its objective of providing a STP class of tariff was to provide a concessional tariff in order to reduce the delivered cost of gas to small communities. Under EAPL's proposal, STP users would pay for the capital costs in return for lower tariffs. The Commission considered that this tariff proposal was appropriate as different pricing can be desirable, provided that economic efficiency tests are met.

Rebatable services

The objectives of the rebatable services initially proposed by EAPL were to promote the growth of the market and the efficient utilisation of the pipeline, which the Commission endorsed in the *Draft Decision*. However, EAPL later submitted that as a result of changing circumstances, the provision of a rebatable service was no longer viable. The Commission accepted EAPL's submission to remove rebatable services and proposed that the access arrangement be amended accordingly.

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[371] NERA submission on behalf of Incitec, 15 July 1999, p. 11.

2.9.1.4 Submissions in response to the Draft Decision

No submissions were received in response to this issue.

2.9.1.5 Revised access arrangement

Tariffs and tariff path

In its revised access arrangement, EAPL proposed that reference tariffs would vary over the access arrangement period in accordance with a CPI-X price path. EAPL also proposed that tariffs may vary should a specific pass through event occur, or should EAPL decide to vary the determination of lateral tariffs within the access arrangement period.

In attachment C1 of its revised access arrangement, EAPL presented reference tariff information on the mainline and laterals under a number of different scenarios to reflect its application for the revocation of coverage on the Moomba to Wilton pipeline and the Canberra lateral. The tariff scenarios included were when:

- all the pipeline was covered;
- coverage on the Moomba to Wilton pipeline and Canberra lateral was revoked and the Wagga lateral and regional laterals remained covered;
- coverage on the Moomba to Wilton pipeline is revoked and the Wagga lateral, Canberra lateral and regional laterals remain covered; and
- coverage on the Canberra lateral is revoked, while the Moomba to Wilton pipeline, Wagga lateral and regional laterals remain covered.

As discussed in previous chapters, in May 2003 EAPL submitted revised volume forecasts as well as changes to a number of other elements such as capital expenditure. In response to a request by the Commission, EAPL provided a revised access arrangement information document and revised revenue and tariff models consistent with the new forecast volumes. As a result, the tariffs proposed by EAPL in attachment C1 of the revised access arrangement are no longer valid. The new revised tariffs proposed by EAPL are presented in Table 2.9.1.1 and Table 2.9.1.2. The starting point (commencing in October 2002) proposed by EAPL for tariffs on both the mainline and lateral pipeline segments is the current MSP published firm service tariffs ($0.0004764/GJ/km for capacity and $0.0000299/GJ/km for throughput).

Table 2.9.1.1: Average capacity and commodity charges ($/GJ/km)

Year ending 30 June	2004	2005	2006	2007	2008
Mainline					
Capacity charge	0.0004876	0.0004991	0.0005108	0.0005229	0.0005352
Throughput charge	0.0000306	0.0000313	0.0000321	0.0000328	0.0000336
Regional Laterals					
Capacity charge	0.0005088	0.0005433	0.0005803	0.0006197	0.0006618
Throughput charge	0.0000319	0.0000341	0.0000364	0.0000389	0.0000415

Source: EAPL model and revised access arrangement information, 8 July 2003

Note: These tariffs do not include GST

Table 2.9.1.2: Tariffs proposed by EAPL (nominal $/GJ)

	2004	2005	2006	2007	2008
Moomba to:					
Wilton	0.673	0.689	0.705	0.722	0.739
Young	0.535	0.548	0.561	0.574	0.588
Culcairn	0.649	0.664	0.680	0.696	0.712
Lithgow	0.673	0.719	0.768	0.820	0.876
Griffith	0.712	0.760	0.812	0.867	0.926
Canberra	0.616	0.631	0.646	0.661	0.676

Source: EAPL model and revised access arrangement information, 8 July 2003.
Note: These tariffs do not include GST.

As illustrated in Table 2.9.1.2, EAPL has proposed different tariffs for the mainline and laterals both with capacity and throughput tariffs. In contrast to the original access arrangement, EAPL has now included the Dalton to Canberra lateral as part of the mainline (see section 2.11 of the *Final Decision* for details on the cost allocation approach).

The revised access arrangement information sets out that the mainline tariffs during the initial access arrangement period will be indexed by CPI-X, which is designed to provide a smooth price path for users. EAPL did not specify the escalation formula in the revised access arrangement, but did so in its revised access arrangement information document as follows:[372]

$$RT_n = RT_{n-1} \times (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}) \times (1 - X)$$

Where:

RT_n = Reference Tariff in $year_n$

RT_{n-1} = Reference Tariff in $year_{n-1}$

CPI = Consumer Price Index (All Groups – weighted Average Eight Capital Cities) published quarterly by the Australian Bureau of Statistics (ABS).

CPI_n = CPI published for the March quarter in $year_n$

CPI_{n-1} = CPI published for the March quarter in the $year_{n-1}$

X = revenue smoothing factor.

EAPL proposed an X of positive 4 per cent for the mainline through the first access arrangement period. According to EAPL, this X was chosen to accommodate volume forecasts, to provide a consistent tariff for the remainder of the economic life of the MSP, to reduce price shocks to EAPL and customers and to provide a clear rounded tariffs for users.[373]

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[372] EAPL revised access arrangement information, 7 July 2003, p. 26.

[373] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 9.

Given the importance of volume forecasts and the ICB in the determination of the X factor and hence tariff path, the changes submitted by EAPL in 2003 have had a material impact on the 4 per cent initially proposed. Consequently, in light of the new forecasts, EAPL now proposes an X factor of 0.33 per cent per year. That is, mainline tariffs will decline by 0.33 per cent in real terms each year of the access arrangement period.[374]

In the original access arrangement EAPL proposed a relatively complex reference tariff formula for the lateral pipelines which used CPI in 2000 as the basis of any yearly adjustment. For the purposes of the revised access arrangement, EAPL has put forward an amended reference tariff formula for the lateral pipelines which is identical to that noted above with regard to the mainline reference tariff formula. An X factor of negative 4 per cent for lateral tariffs has been proposed and this value has been maintained following the submission of downwardly revised volumes.

Backhaul and adjustments to the tariff path

As in the initial application, the revised access arrangement provides a discount for the backhaul of gas on the MSP. Specifically, clause 6.12 of the revised access arrangement states that if in any month the user's gas flows in the opposite direction as the predominant physical flow of gas, then the user will be entitled to a 50 per cent reduction on the capacity charge and a waiver of the throughput charge for the relevant quantity of gas for that segment.

Non-tariff charges, STP tariff and rebatable services

The revised access arrangement provides for non-tariff charges in certain circumstances.[375] These charges include overrun, odorisation, balancing charges and daily variance charges. The Commission has considered the nature and magnitude of these charges in Chapter 3 of this *Final Decision*. The STP and rebatable services initially proposed by EAPL were removed from the revised access arrangement. This left only one reference service (the firm transportation service) and a negotiable service.

2.9.1.6 Submissions in response to the revised access arrangement

In response to the revised access arrangement TXU stated that it was difficult to provide a definitive response regarding EAPL's tariff proposals, given the lack of information. TXU in particular noted the significant increase in non capital costs and the change in the depreciation approach proposed in the revised access arrangement.[376]

With regard to the proposed tariffs, TXU noted that it was difficult to contemplate a reference tariff policy which included a mechanism to move from a regulated tariff to a competitive tariff, should coverage of elements of the MSP pipeline be revoked. Specifically, TXU noted that EAPL had not proposed an adjustment mechanism in the event that coverage is revoked on parts of the MSP and noted that the movement to

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[374] EAPL revised access arrangement information, 7 July 2003, p. 26.

[375] EAPL revised access arrangement, 30 April 2002, Attachment C5, pp. 28-30.

[376] TXU submission (covering letter), 23 August 2003, p. 2.

competitive tariffs may not result in efficient outcomes which accord with section 8 of the Code. It suggested that if significant tariff increases were proposed for remaining covered pipelines in the event of revocation, it may be more appropriate to trigger a review before the expiry of the access arrangement period.[377]

2.9.1.7 Commission's considerations

CPI-X formula

EAPL has proposed a reference tariff variation method which incorporates a CPI-X price path, a pass through mechanism and the option to review lateral tariffs within the initial access arrangement period. The Commission considers that under the terms of the Code, the proposal put forward by EAPL represents a hybrid price path, trigger event and reference tariff variation methodology. The Commission has assessed this approach and is of the view that such a hybrid mechanism is consistent with the provisions set out in section 8.3 of the Code. With regard to the price path aspect of the proposal, the Commission has assessed the reference tariff formula provided by EAPL in section 5.6.1 of its revised access arrangement information and is of the view that it is broadly consistent with the Commission's proposed amendment A2.13 of the *Draft Decision*.

However, the Commission has a number of concerns with the details of the proposed reference tariff formula. First, the Commission is concerned with the placement of the CPI-X adjustment mechanism in the revised access arrangement information but not in the access arrangement document. This concern stems from the fact that the revised access arrangement document submitted by EAPL does not recognise the price path approach proposed. The Commission encourages EAPL to incorporate the price path adjustment mechanism (including amendments required by the Commission) into the revised access arrangement and to remove any inconsistencies associated with this issue within the access arrangement information documentation.

A second issue associated with the CPI-X mechanism relates to the timing implied in the equation and in the models provided by EAPL. The commencement date of the access arrangement proposed by EAPL in its revised documentation was 1 October 2002. However, given the timing of the release of the *Final Decision* the commencement date is now expected to be 1 January 2004. If EAPL's proposal for tariffs to change on a financial year basis is adopted, tariffs in the first half of 2004 and last half of 2008 would relate to cost data that is outside of the access arrangement period (that is, costs in the second half of 2003 and last half of 2004), which is not appropriate under the provisions of the Code.

A workable solution to this problem is to assume that financial year data ending 30 June each year relates to the calendar year that these cash flows are incurred. For example, costs incurred on 30 June 2004 would be assumed to relate to the calendar year 2004 rather than the period 1 July 2003 to 30 June 2004. This assumption is appropriate given that the CPI-X adjustment mechanism determines tariffs and thus revenues over a 12 month period which has a nominal present value determined at 30 June each year. As the graph below demonstrates, the calendar year represents the

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[377] TXU submission, 23 August 2003, pp. 2-3.

obvious period over which revenue should be achieved since the average price level in any year would normally be expected to be that prevailing at the middle of the year.

To achieve the above outcome, the tariff based on the cash flow at 30 June 2004 needs to be linked to the volume forecast to be transported on the pipeline in calendar year 2004. Similarly, the revenue cash flow evaluated at 30 June 2005 needs to be linked to tariffs and volumes relevant to calendar year 2005 with the same pattern applying in later years of the access arrangement period.

A third concern associated with the tariff path proposed by EAPL relates to the proposal to use CPI data from the March quarter each year. The adoption of a calendar year assumption logically implies that the CPI-X adjustment should occur at the end of each calendar year. Assuming an adjustment at this time, the latest available CPI data would be the September quarter data. The Commission considers that the September quarter data would be more appropriate for the annual CPI adjustment.

Fourth, the mechanism presented by EAPL does not specify beginning and end dates for the CPI-X adjustment formula. Following the approach adopted in past decisions, the Commission is of the view that the initial CPI adjustment should occur in December 2004 and the last in December 2007 in order to establish tariffs for the last calendar year of the initial access arrangement period.

Also, an inflation assumption is required for the first year otherwise the price level of the tariffs will never catch up to the actual price level. This problem is resolved by using the forecast inflation assumption over the access arrangement period to establish the reference tariff for the first year of the period (that is, 2004).[378] With this approach it can be shown that regardless of the time profile of actual inflation during the period, overall compensation for actual inflation is achieved in NPV terms. Since the inflation adjustment lag affects all years, this approach most closely compensates for the imperfections in the inflation adjustment mechanism. Under this approach the service provider is neither systematically advantaged nor disadvantaged. That is, over a number of access arrangement periods any cumulative residual impact of inflation adjustment errors would be negligible.

In light of the above discussion, the Commission requires the following amendment be made.

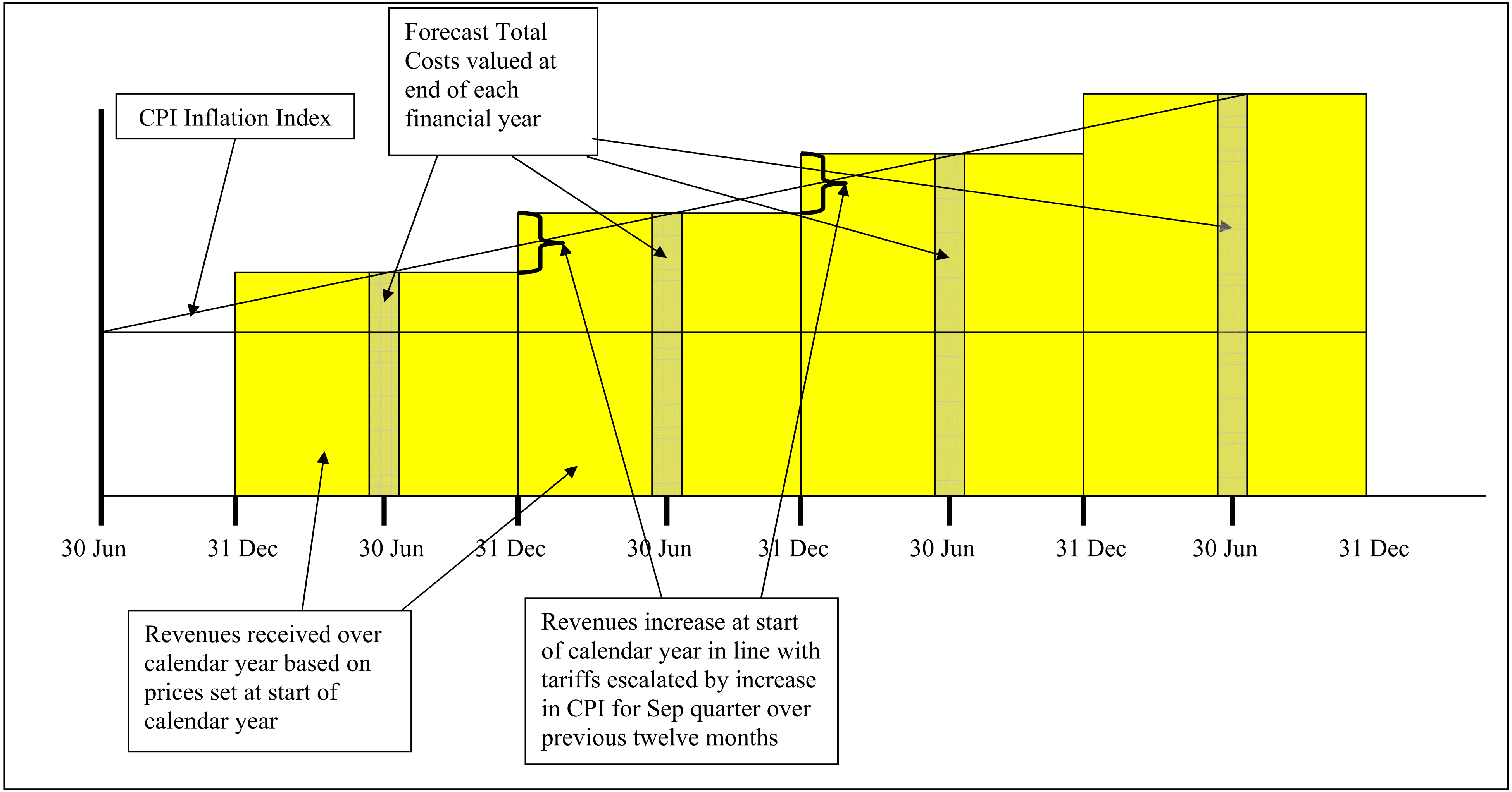
[378] See section 2.6 for details of the calculation of forecast inflation over the access arrangement period.

Amendment FDA 11

In order for EAPL’s access arrangement for the MSP to be approved, EAPL must:

- include details of the price path adjustment mechanism in its access arrangement document;
- use September quarter data as the basis of the annual CPI adjustment in 2004 through to 2007;
- specify that the annual CPI adjustment would come into effect on 1 January for the years 2005 through 2008; and
- specify that forecast inflation will be used to calculate tariffs in the first year of the access arrangement period.

Figure 2.9.1.1: Graphical representation of cash flows and tariff escalation



The Commission recognises that EAPL's price path mechanism is silent on the approval method that is to be followed at each annual tariff reset. This is despite the provision set out in section 8.3A of the Code which requires that a reference tariff may only vary within an access arrangement period in accordance with the implementation of an approved reference tariff variation method.

In accordance with these Code provisions and the method adopted in previous Commission approved access arrangements, EAPL must adopt the following amendment which sets out provisions concerning the procedure to be followed when EAPL wishes to vary tariffs in accordance with its proposed price path mechanism.

Amendment FDA 12

In order for EAPL's access arrangement for the MSP to be approved, EAPL must include the following provisions into the access arrangement:

- EAPL must provide a notice to the Commission of its proposed revised tariffs in accordance with the reference tariff formula and approved X values 30 days business days prior to 31 December 2004 and each subsequent year until 31 December 2007.
- This notice must specify that the proposed variations to the reference tariff applies from 1 January of the relevant year.
- The Commission will assess the proposed tariffs provided by EAPL and determine if they comply with the relevant CPI-X formula. The Commission will publish its decision within 20 business days of EAPL lodging its submission. The Commission may either approve the revision, disallow the variation or may specify a complying variation. If a complying variation is required, this will be taken to be approved on the 21st business day after lodgement and come into effect on 1 January of the relevant year.
- If the Commission does not provide a notice within 20 business days, the Commission will be taken to have approved the revised tariffs, which will come into effect on 1 January of the relevant year.
- Before the expiry of the 20 business days after submission, the Commission may request additional information if it considers that such information will assist its assessment. This will extend the relevant assessment period by the number of days commencing on the day on which the Commission gave notice to EAPL and ending on the day on which EAPL submits the required information.
- The Commission may grant an extension on application by EAPL of any of the time periods associated with this process.

X factors and tariffs

As foreshadowed above, with regard to the mainline EAPL has proposed a price path starting from the current published tariffs according to CPI-X. In light of new volume forecasts submitted, EAPL proposed an X factor of 0.33 per cent to operate over the first access arrangement period.

The Commission has assessed EAPL's price path proposal for the mainline with regard to the amendments required in other areas of this *Final Decision*. An X factor of 0.33 per cent starting from current published tariffs generates a significant over recovery of costs over the life of the asset. The Commission considers that this outcome is inconsistent with the intent of the NPV approach as the NPV of revenues generated would be greater than zero.

The Commission has also assessed EAPL's tariff path proposal to determine compliance with Code provisions. First, the Commission assessed the tariff path and revenue outcomes when current published tariffs are used as the starting point. Given the significant difference between EAPL's and the Commission's total revenue estimations, the use of published tariffs generates a perverse result whereby forecast revenues recover the total value of the capital base prior to the end of the life of the asset. That is there is an over recovery of costs.

Second, the Commission has modelled EAPL's tariff path proposal for the mainline assuming an X factor of 0.33 per cent. The Commission considers that this also generates an inappropriate result. An X factor of 0.33 per cent is associated with an initial drop in tariffs of 36 per cent, which may be construed as a significant 'tariff shock' for users and the service provider. Moreover, an X factor of 0.33 per cent using the Commission's revenue assumptions generates a situation which is contrary to the back end loaded depreciation schedule proposed by EAPL and accepted by the Commission (see section 2.5 of the *Final Decision*).

Given the problematic nature of EAPL's mainline tariff proposal, the Commission has assessed a number of tariff path and initial tariff reduction combinations that allow EAPL to recover forecast costs. Given that there is almost an infinite number of combinations, the Commission has limited its assessment to the following:

Table 2.9.1.3: Initial reduction in tariffs and tariff path combinations

Initial reduction in mainline tariffs	Associated X factor
14%	2.2%
16%	2.0%
18%	1.9%
21%	1.6%
22%	1.5%
28%	1.0%

Source: Commission modelling.

Of the above tariff path options, the Commission has concluded that an X factor of 1.6 per cent with an initial reduction in tariffs of 21 per cent provides the most appropriate outcome in this instance. The Commission is of the view that this proposal provides the service provider with the opportunity to recover efficient costs (section 8.1(a)) and should not distort incentives (section 8.1(f)). Moreover, a tariff path of 1.6 per cent provides EAPL with a back end loaded depreciation schedule which aligns depreciation charges with the path of volume changes over the life of the asset. As noted in section 2.5, given the projected volumes a back end loaded depreciation schedule should replicate the outcome expected by a firm operating in a competitive market situation (in accordance with section 8.1(b)). This should also promote efficiency in the level of reference tariffs (8.1(e)) and promote efficient investment (in accordance with section 8.1(d)).

The Commission also considers that a tariff path of 1.6 per cent accords with the elements set out in section 2.24 of the Code. Specifically, the proposed tariff path should forge a balance between the interests of users and EAPL (thus promoting the considerations set out in section 2.24(a) and (f) of the Code). This is because the initial reduction in tariffs provides users with an immediate benefit in terms of lower prices, but one which the Commission considers does not represent an excessive 'tariff shock' from the perspective of EAPL. Moreover, given that this tariff path generates a back end loaded depreciation schedule, it should promote the economically efficient operation of the pipeline in accordance with section 2.24(d), and also the public interest in having competition in markets (section 2.24(e)).

With regard to lateral tariffs, EAPL has proposed a price path starting from current published tariffs moving over the access arrangement period in real terms by negative 4 per cent. As with the mainline tariff path, Commission modelling of this proposed tariff path in light of the revisions required in the *Final Decision* generates a substantial over-recovery of revenues.

Given this, the Commission has also assessed elements of EAPL's proposal for regional laterals against the provisions set out in the Code. An assessment of the tariff path when an X factor of negative 4 per cent is adopted has been undertaken given the Commission's assumptions regarding ICB, non capital costs and the return on assets. The Commission considers that the proposed approach generates an inappropriate result as it is associated with an initial drop in tariffs in excess of 59 per cent. Moreover, given relatively low initial tariffs, this proposal is associated with a substantial under recovery of costs in the first access arrangement period which may not promote efficiency in the level of reference tariffs (section 8.1(e)) and has the potential to distort upstream and downstream investment decisions (section 8.1(d)).

The Commission has also assessed the lateral tariff path with current published tariffs as the starting point. In contrast to the mainline, the use of current published tariffs generates a workable result for regional laterals which is associated with an X factor of positive 0.38 per cent. This implies that tariffs will fall in real terms by 0.38 per cent over the course of the initial access arrangement period.

The Commission considers that the adoption of an X factor of 0.38 per cent meets the requirements set out in section 8.1 of the Code. Specifically, it provides the service provider with the opportunity to recover efficient costs (section 8.1(a)), replicates the outcome of a competitive market through the retention of a back end loaded depreciation schedule (section 8.1(b)) and should promote efficient costs in accordance with section 8.1(e) of the Code. Moreover, given recovery of non capital costs, return on assets, tax and some economic depreciation at the outset, this tariff path promotes efficiency in the level of the reference tariff in accordance with section 8.1(e) and should encourage efficient pipeline and upstream and downstream investment (section 8.1(d)) over the long term.

The Commission also considers that a tariff path of 0.38 per cent starting from current published tariffs on regional laterals generates outcomes which are consistent with section 2.24 of the Code. Given the recovery of costs, this tariff path should promote the legitimate interests of the service provider (section 2.24 (a)), the economically efficient operation of the pipeline (in accordance with section 2.24(d)) and the public interest in having competition in markets (section 2.24(e)). In addition, the proposed X factor is associated with a fall in tariffs in real terms over the access arrangement period which should promote the interests of users and prospective users in accordance with section 2.24(f)).

The tables below summarises the tariff path for mainline and lateral pipelines as proposed by the Commission (excluding GST). These tariffs are in nominal dollar terms assuming a CPI of 2.19 per cent throughput the course of the access arrangement period.

Table 2.9.1.4: Tariffs required by the Commission (nominal $/GJ per km)

	2004	2005	2006	2007	2008
Mainline					
Capacity charge	0.000377267	0.000379376	0.000381496	0.000383628	0.000385772
Throughput charge	0.000023678	0.000023811	0.000023944	0.000024077	0.000024212
Regional Laterals					
Capacity charge	0.000485021	0.000493798	0.000502734	0.000511831	0.000521093
Throughput charge	0.000030441	0.000030992	0.000031553	0.000032124	0.000032705

Source: Commission modelling.
Note: These tariffs do not include GST.

Adoption of the above baseline tariffs generates the tariffs on a $/GJ basis for each pipeline segment as denoted in table below.

Table 2.9.1.5: Tariffs required by the Commission by pipeline segments (nominal $/GJ)

	2004	2005	2006	2007	2008
Moomba to:					
Wilton	0.5208	0.5237	0.5267	0.5296	0.5326
Young	0.4141	0.4165	0.4188	0.4212	0.4235
Culcairn	0.5020	0.5048	0.5076	0.5104	0.5133
Lithgow	0.6418	0.6534	0.6652	0.6772	0.6895
Griffith	0.6789	0.6911	0.7037	0.7164	0.7294
Canberra	0.4741	0.4767	0.4794	0.4821	0.4848

Source: Commission modelling.
Note: These tariffs do not include GST.

As discussed, attachment C1 to C4 of EAPL's revised access arrangement sets out tariffs under a number of different pipeline coverage scenarios. The Commission notes that while EAPL has set out reference tariffs under different coverage scenarios, EAPL has not proposed a specific trigger event approach with regard to the coverage issue. The Commission has proceeded on the basis that the MSP will remain a covered pipeline and has calculated tariffs and revenues accordingly. Nevertheless, it does acknowledge EAPL's ability to propose revisions to its access arrangement at any time during the initial access arrangement period. As resolution of the coverage issue remains, the use of a section two revisions process appears to be the most appropriate course of action at this time. The Commission therefore requires the following amendment.

Amendment FDA 13

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace the tariffs proposed in Attachment C1 with those set out in Table 2.9.1.4. EAPL must also delete Attachments C2, C3 and C4 from the revised access arrangement.

Backhaul

In the *Draft Decision* the Commission noted that the backhaul rate of 50 per cent of capacity charges may not be inappropriate, primarily as it would operate along the Young to Culcairn pipeline which is characterised by varying direction in flow. The Commission maintains that this charge may be reasonable along the Young to Culcairn pipeline. This is because:

- Revenues from backhaul charges are used to derive reference tariffs, meaning that backhaul volumes will not generate additional revenue unless volumes are higher than forecasts;
- The flow of gas along the Young to Culcairn pipeline may vary depending on volumes operating at the time. Accordingly, it would be inappropriate for users to be subject to reference tariffs in some instances and then markedly reduced backhaul tariffs at other times; and
- It is unclear whether backhaul gas would be physically shipped along the pipeline or whether swap arrangements would be entered into with users moving gas in the opposite direction. Should the gas be physically shipped the costs incurred would not be negligible providing further justification for the imposition of backhaul charges.

The Commission did not receive any submissions from interested parties relating to the operation of backhaul charges along other pipelines which form the MSP. In addition, the Commission is aware that backhaul is unlikely to occur along any other segment of the pipeline system. Accordingly, the Commission is satisfied that the proposed backhaul charge meets the principles set out in section 8.1 of the Code.

2.9.2 Forecast revenues

2.9.2.1 Code requirements

The Code sets out under section 8.4 three alternative methodologies for determining total revenue: Cost of Service, IRR and NPV. Section 8.5 allows for the use of other methodologies provided that the resulting total revenue can be expressed in terms of one of the three methodologies noted above.

Section 8.6 of the Code recognises that, in view of the manner in which various parameters such as the rate of return, ICB, depreciation schedule and non capital costs may be determined, it is feasible that a range of values may be attributed to total revenue. In order to determine an appropriate value within this range, the Commission may have regard to any financial and operational performance indicators it considers relevant in order to determine the level of costs that is most consistent with the objectives contained in section 8.1 of the Code.

2.9.2.2 Original access arrangement

In its original proposed access arrangement, EAPL proposed a cost of service methodology to determine revenue over the initial access arrangement period. The cost categories which made up total revenue were return on assets, depreciation, and non capital costs. Total revenue and the components of this initially proposed by EAPL are set out in Table 2.9.2.1 below.

Table 2.9.2.1: EAPL's original revenue proposal (July 2000 $ million)

Year ending 30 June	2001	2002	2003	2004	2005
Return on assets	55.157	53.429	52.090	50.811	48.930
Depreciation	24.032	24.125	24.674	25.032	25.115
Non capital costs	12.264	13.255	12.406	13.636	12.430
Total revenue	**91.453**	**90.809**	**89.170**	**89.478**	**86.475**

Source: EAPL access arrangement information, May 1999, p. 52.

To create a smooth price path across the access arrangement period, EAPL proposed that tariffs should vary by a CPI-X formula, meaning that forecast revenue and target revenue would differ slightly in each year. However, to ensure no under or over recovery of costs arose, EAPL set the X factor so that the NPV of the two revenue streams was identical.

2.9.2.3 Commission's Draft Decision

In the *Draft Decision*, it was determined that the cost of service and tariff path approach proposed by EAPL was appropriate and consistent with the requirements of the Code. However, the Commission concluded that EAPL's revenue requirements were overstated and proposed a substantial decline in target revenues across the access arrangement period.

2.9.2.4 Submissions in response to the Draft Decision

A number of submissions were received by interested parties with regard to specific elements of total revenue, such as the ICB and the rate of return. However, no submissions were received which commented specifically on the Commission's approval of the cost of service methodology proposed by EAPL.

2.9.2.5 Revised access arrangement

As foreshadowed earlier in this *Final Decision* and at the start of this section, EAPL has proposed the NPV approach to determine its total revenue over the access arrangement period. In its revised access arrangement information, EAPL noted that the proposed NPV methodology represents the same methodology as that approved by the Commission for the CWP.[379]

On the basis of the parameter assumptions proposed by EAPL in its revised access arrangement, EAPL estimated the following total revenue requirements for both the regional laterals and mainline.

Table 2.9.2.2: Total revenue – mainline (2001 $ million)

Year ending 30 June	**2003(a)**	**2004**	**2005**	**2006**	**2007**	**2008**
Asset base	689.99	685.09	683.37	683.83	683.25	684.76
Return on assets	36.35	54.13	54.00	54.03	53.99	54.11
Non capital costs	15.52	20.83	20.75	20.75	20.75	20.75
Economic depreciation	1.94	4.50	0.97	0.93	-1.15	-5.07
Total Revenue	**53.81**	**79.47**	**75.72**	**75.72**	**73.59**	**69.79**

Note (a) Total revenue for 2003 is for a 9 month period (1 Oct 2002 - 30 June 2003).
Source: EAPL revised access arrangement information, 8 July 2003. EAPL's models suggests that data is in $2001 not $2000 terms as suggested in the revised access arrangement information submitted on 8 July 2003.

Table 2.9.2.3: Total revenue – regional laterals (2001 $ million)

Year ending 30 June	**2003(a)**	**2004**	**2005**	**2006**	**2007**	**2008**
Asset base	64.54	67.53	70.69	73.61	80.39	83.44
Return on assets	3.40	5.34	5.59	5.82	6.35	6.59
Non capital costs	1.29	1.74	1.74	1.74	1.74	1.74
Economic depreciation	-2.10	-2.93	-2.89	-2.81	-3.02	-2.92
Total Revenue	**2.59**	**4.15**	**4.44**	**4.74**	**5.06**	**5.41**

Note (a) Total revenue for 2003 is for a 9 month period (1 Oct 2002- 30 June 2003).
Source: EAPL revised access arrangement information, 8 July 2003. EAPL's models suggests that data is in financial year 2001 dollars not financial year 2000 dollar terms as suggested in the revised access arrangement information submitted on 8 July 2003.

2.9.2.6 Submissions by interested parties

As with the *Draft Decision*, certain interested parties commented on aspects of EAPL's revised target revenue, but no objection was raised with regard to the approach proposed.

2.9.2.7 Commission's considerations

As discussed in section 2.1 of this *Final Decision*, the Commission recognises that EAPL's proposed use of the NPV approach is consistent with sections 8.4 and 8.5A of the Code. The Commission, however, is of the view that a number of EAPL's smoothed total revenue requirements are actually overstated in its revised access arrangement and access arrangement information, and has proposed amendments to this effect throughout this *Final Decision*. Furthermore, the Commission considers, for the reasons set out above, that a CPI-X tariff path with X equal to 1.60 per cent for the

379 EAPL revised access arrangement information, 7 July 2003, p. 23.

mainline and 0.38 per cent for the laterals should be adopted, and that revenue should be in calendar rather than financial year terms.

The following tables summarise the Commission's estimation of EAPL's revenue over the access arrangement period consequent to the amendments required by the Commission with respect to the ICB, non capital costs, return on assets, volumes and tariff path.

Table 2.9.2.4: Mainline revenue 2004-2008 (July 2003 $ million)

Year ending December 31	**2004**	**2005**	**2006**	**2007**	**2008**
Return on assets	30.49	29.72	28.99	28.29	27.78
Non capital costs	17.12	17.16	17.30	17.43	17.56
Economic depreciation	16.01	13.77	12.24	9.05	7.95
Total revenue	**63.61**	**60.65**	**59.04**	**57.72**	**56.05**

Source: Commission modelling.
Note: Totals may differ due to rounding.

Table 2.9.2.5: Regional lateral revenue 2004-2008 (July 2003 $ million)

Year ending December 31	**2004**	**2005**	**2006**	**2007**	**2008**
Return on assets	2.58	2.59	2.57	2.80	2.78
Non capital costs	1.45	1.45	1.47	1.48	1.49
Economic depreciation	0.22	0.31	0.42	0.28	0.33
Total revenue	**4.25**	**4.35**	**4.45**	**4.56**	**4.60**

Source: Commission modelling.
Note: Totals may differ due to rounding.

The table below provides a comparison between revenues proposed by EAPL and those required by the Commission for the period 2004-2008 for both the mainline and regional laterals.

Table 2.9.2.6: Comparison of total revenues (July 2003 $ million)

	2004	2005	2006	2007	2008
Revenue proposed by EAPL[a]					
Mainline	84.20	80.62	81.00	79.11	75.39
Regional	4.40	4.72	5.07	5.44	5.85
Total	**88.60**	**85.35**	**86.07**	**84.56**	**81.24**
Revenue consistent with Final Decision					
Mainline	63.61	60.65	59.04	57.72	56.05
Regional	4.25	4.35	4.45	4.56	4.60
Total	**67.87**	**65.00**	**63.48**	**62.28**	**60.65**
Difference	*20.73*	*20.35*	*22.59*	*22.28*	*20.59*

Source: EAPL revised access arrangement information and ACCC modelling.
Note: (a) Converted by the Commission to a financial year 2003 base year

Gas Transportation Deed

The GTD is an agreement between EAPL and AGLWG that operates from 1 July 2000 to 1 January 2017. This deed represents the main revenue contract for the MSP. Under the GTD, AGLWG must pay EAPL a series of minimum monthly payments over the period 1 July 2000 to 1 January 2007. These payments will be used to offset AGLWG's liability to pay the tariff, which is determined by reference to the minimum published tariff.

Should liabilities from tariffs exceed this amount, then AGLWG must make additional payments to EAPL, unless it has credits from previous months if the amount paid exceeded liabilities.[380] However, AGLWG will cease to have the right to require EAPL to use any notional credit from these monthly payments which, as at 1 January 2007, has not been required to satisfy AGLWG's liability to pay the tariff. From 1 January 2007, the required minimum monthly payment expires. From this time until 1 January 2017, EAPL must provide transportation services to AGLWG, and the tariff that will be charged for this service will be the minimum published reference tariff.[381]

Accordingly, under the GTD EAPL is guaranteed a certain amount of revenue from AGLWG through to 1 January 2007. The annual payments required under the GTD are set out at confidential Appendix F. A broad indicator of the revenue resulting from the GTD can be found in the March 2000 APT Prospectus. As the figure below from the prospectus indicates, revenue arising from the GTD is a large proportion of total forecast pipeline revenue over the period 2001-2006. The proportion of revenue from the GTD declines through this period up until the point that the minimum monthly payments conclude.

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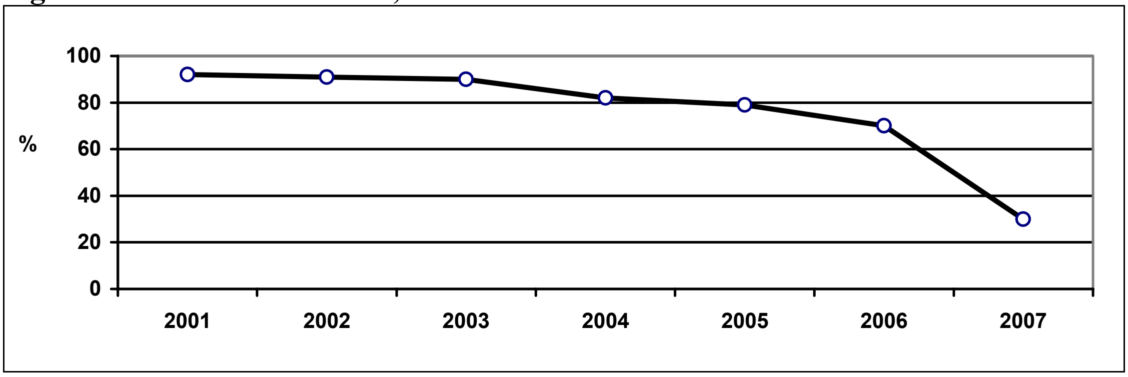
[380] APT, *Buried Treasure – Offer document*, March 2000, p. 66.

[381] APT, *Buried Treasure – Offer document*, March 2000, p. 66.

Figure 2.9.2.1: GTD revenue, 2001-2007



Source: APT, *Buried Treasure – Offer document*, March 2000, p. 28.

The revenue guarantee under the GTD effectively means that the regulated tariffs approved by the Commission from 2004 through 2006 will have limited impact on EAPL's income stream until 1 January 2007. However, the reference tariffs will be relevant for third parties that may wish to use the MSP. In addition, and perhaps more importantly, the tariffs will play a dominant role from 1 January 2007 once the minimum payments under the GTD expire.

2.10 Reference tariff variation policy

Section 2.9 of this *Final Decision* assessed issues relating to the tariff path proposed by EAPL as well as its forecast revenue. As discussed in that chapter, under the NPV approach revenue is effectively an exogenous factor which is determined as the product of the path of tariffs and forecast volumes over the access arrangement period. Given this interrelationship, it was proposed that these two issues should be evaluated jointly in the one chapter.

The tariff path, however, represents just one element of the reference tariff policy proposed. As noted, EAPL has also proposed a trigger event adjustment mechanism in the form of a cost pass through and has also proposed a clause that allows lateral tariffs to be changed within the access arrangement period should it wish to do so. It will be the purpose of this section to assess these elements of EAPL's proposed reference tariff variation policy against the provisions set out in the Code.

2.10.1 Pass through mechanism

2.10.1.1 Code requirements

Section 8.3 of the Code provides that a reference tariff may vary within an access arrangement period through the implementation of: a cost of service approach; a price path approach; a reference tariff formula approach; a trigger event adjustment approach or any variation or combination of these approaches. This is subject to the regulator being satisfied that the reference tariff methodology is consistent with sections 8.1 and 8.3A of the Code.

2.10.1.2 Original access arrangement

Initially EAPL proposed that during the first access arrangement period reference tariffs may be adjusted for new or increased taxes, charges, levies, imposts or fees.[382]

2.10.1.3 Commission's Draft Decision

The *Draft Decision* did not comment directly on these matters.

2.10.1.4 Submissions in response to the Draft Decision

There were no submissions made in response to the *Draft Decision* on these matters.

2.10.1.5 Revised access arrangement

Clause 8.7 of EAPL's revised access arrangement states that EAPL has calculated reference tariffs on the basis of government taxes, charges, levies, imposts and fees applicable at 30 April 2002. In the event that any new or increased taxes, charges, levies, duties, imposts or fees occur, or if there is a reduction in the level of these taxes below that assumed, EAPL will adjust tariffs to reflect these charges. This will include any increase or reduction in the level of GST.

Clause 6.13 of the revised access arrangement states that if the introduction of FRC leads to the imposition of new legal or procedural requirements affecting the management or operation of the pipeline, then users must reimburse their proportion of these costs to EAPL. This clause further states that EAPL is entitled to vary the terms of the Transportation Agreements to this effect.

2.10.1.6 Submissions in response to the revised access arrangement

ExxonMobil Gas Marketing (Exxon Mobil) expressed concern with EAPL's proposal under clause 6.13 to recover from users the costs associated with FRC. ExxonMobil stated that this clause does not provide any limitation on these costs and that FRC costs should be clarified to only allow recovery of direct and reasonable costs associated with a particular user.[383]

TXU noted that clause 6.13 provides for the effective pass through of costs associated with FRC which may affect the management or operation of the pipeline. TXU stated that it supported the pass through of costs, but argued that it was unlikely that such costs would be incurred given that FRC has already been implemented in NSW. TXU also suggested that such costs should not be dealt with under an access arrangement. TXU argued that in the event that the Commission agrees with EAPL's proposal, the pass through of FRC should be amended to allow for:

- confirmation by an independent party that the costs incurred are necessary for EAPL to perform its services;
- confirmation by an independent party of the reasonableness of the costs incurred;
- clarity as to the effective date of the pass through mechanism; and

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382 EAPL access arrangement, 5 May 1999, p. 10.

383 ExxonMobil submission, 10 July 2002, p. 1.

- appropriate notification of when such costs are to be imposed.[384]

TXU also commented on the pass through proposed by EAPL for increases in government taxes, charges, levies, imposts and fees applying at 30 April 2002. TXU raised a number of concerns with regard to this proposal. It noted that: the definition of costs seemed too broad and was inconsistent with incentive regulation and the intention of the Code; that the mechanism is ambiguous with regard to the pass through of decreases in these costs; and the mechanism may occur in a non-transparent manner which may result in the shifting of costs to users. TXU accordingly requested that the Commission in the first instance assess the appropriateness of the proposal and then consider whether such a mechanism is consistent with the Code. To ensure best regulatory practice TXU suggested that EAPL be required to submit any proposal to the Commission for approval prior to on-charging users, consult with affected users and only adjust for the net cumulative impact of total pass through events.[385]

EAPL's response to submissions

In its response to submissions, EAPL commented on ExxonMobil's concern that the costs associated with FRC should only recover costs associated with a particular user. EAPL noted that as FRC costs will be associated with all users, EAPL would not reasonably be required to only pass on costs associated with a particular user, but should be able to recover its costs by proportionate contributions from all users.[386]

EAPL also stated that TXU's proposal to recover FRC costs separately from the access arrangement was not possible under the Code, and that the revised access arrangement allowed EAPL to only recover those costs it actually incurs in the facilitation of a competitive market, which it considered simple and reasonable.[387] In addition, EAPL noted that the pass through for items such as taxes and licence fees was not incompatible with incentive regulation given that incentive regimes allow for the pass through of costs where there is no doubt about prudence. EAPL considered that the items to be included in the pass through mechanism had been accepted in many contracts and access arrangements, including the CWP.[388]

2.10.1.7 Commission's considerations

As discussed previously in this *Final Decision*, the Commission considers that the reference tariff variation methodology proposed by EAPL is consistent with the provisions of section 8.3 of the Code. Under this aspect of the Code, the pass through mechanism proposed by EAPL is categorised as a trigger event adjustment approach. Sections 8.3-8.3H of the Code set out, among other things, the requirements of a reference tariff policy, which may include such an approach. These provisions allow for the regulator to consider both the subject matter of the tariff variation proposed by

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384 TXU submission, 18 August 2002, pp. 1-2.

385 TXU submission, 18 August 2002, pp. 3-5.

386 EAPL response to submissions, 25 September 2002, pp. 1-2.

387 EAPL response to submissions, 25 September 2002, p. 5.

388 EAPL response to submissions, 25 September 2002, p. 5.

the service provider, as well as the specific method of variation. These two elements of the proposed pass through are assessed below.

Scope of the pass through

Section 8.3 of the Code specifies that the manner in which a reference tariff may vary within an access arrangement period is within the discretion of the service provider subject to section 8.3A and **the relevant regulator being satisfied that it is consistent with the objectives contained in section 8.1** [emphasis added].

As noted, EAPL has defined a tax event as the introduction of new or increased taxes, charges, levies, duties, imposts or fees. The Commission is of the view that such a definition of taxes and charges is too broad, and does not comply with the provisions set out in section 8.1 of the Code. Rather, the Commission considers that compliance with section 8.1 principles requires that the tax event:[389]

- be exogenous and beyond the control of management. If pass through costs are endogenous then firms may not face adequate incentives to minimise the relevant costs, in accordance with section 8.1(f) of the Code;
- be of a pronounced magnitude. This should ensure that the costs of the pass through are not outweighed by the administrative costs associated with assessing the pass through event, thereby replicating the outcome of a competitive market under section 8.1(b); and
- affect the regulated firm disproportionately. This is to avoid double counting given that economy-wide shocks may be reflected in any CPI adjustment or compensated through the WACC. This should ensure efficiency in the level and structure of the reference tariff (section 8.1(e)), provide the service provider with the opportunity to recover its costs (section 8.1(a)) and promote efficient investment decisions (section 8.1(d)).

The Commission considers that it is not appropriate to outline what tax provisions would qualify under the above criteria. Alternatively, it is proposed that should a specific tax event occur, it is the responsibility of the service provider to demonstrate that the event meets the above categories should it submit a pass through application to the Commission. As an example, it is likely that a change in the company (statutory) tax rate would meet the above criteria. The event is clearly outside the control of the firm, is likely to have a significant financial impact and will not be fully reflected in the CPI.

The Commission considers that the definition of a tax event proposed by EAPL is also problematic as it is not symmetrical in nature. While clause 8.7 of the revised access arrangement provides for a ‘reduction in the level of those taxes below the level assumed by EAPL’, the Commission concurs with TXU that this definition is ambiguous, primarily because it does not allow for the effects of the removal of a particular tax or charge. A non-symmetrical pass through mechanism does not comply

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[389] David Sappington, *Methods of incentive regulation: design and implementation of hybrid systems,* Presentation to the International Training Program on Utility Regulation and Strategy, Public Utility Research Center, University of Florida, January 2003.

with section 8.1 of the Code, primarily because it would not replicate the outcome of a competitive market (section 8.1(c)), would not promote efficiency in the level and structure of reference tariffs (section 8.1 (e)) and may lead to an over-recovery of costs (section 8.1(a)). Accordingly, the Commission proposes the following amendment:

Amendment FDA 14

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.7 of its revised access arrangement to specify that taxes and charges incorporated in the pass through are exogenous, of pronounced magnitude and affect the regulated firm disproportionately. In addition, EAPL must amend clauses 8.7 of its revised access arrangement to take into account the financial impact of the removal of taxes, charges, levies, duties imposts or fees.

Clause 6.13 of the revised access arrangement states that if the introduction of FRC leads to new legal or procedural requirements affecting the management or operation of the pipeline, then users must reimburse their proportion of EAPL's costs of complying with those requirements.

The Commission considers that a pass through of these costs may not be unreasonable. While FRC has already been implemented in NSW, ACT and Victoria, the Commission acknowledges that new procedural requirements relating to FRC may be imposed on EAPL in future years. Such procedural and legal requirements could potentially have cost consequences which could reasonably be passed through to users during the access arrangement period.

However, as with the tax pass through proposal, it is considered that a flow through of FRC costs would only be appropriate if the event meets the criteria specified above with regard to the tax pass through. Specifically, EAPL would be required to demonstrate that the costs incurred are the result of an exogenous event outside of the company's control. This limits cost changes to legal or procedural requirements imposed by other parties onto the service provider. Following specifications set out in AGL Gas Network's access arrangement, the Commission considers that any new legal or procedural requirements would have to be related to the introduction of a new law relating to retail contestability; or stipulated in a direction of a relevant Minister; or stipulated by a body appointed to implement retail contestability in the gas industry.[390]

For example, EAPL is currently an informal stakeholder in the Gas Marketing Company, which is a gas industry owned body established to develop and operate retail market arrangements in NSW and ACT.[391] Should EAPL become a formal member of the Gas Marketing Company and be bound by the rules of the association, then it may incur additional costs which could legitimately be passed onto users. Costs associated with its role as an informal stakeholder, however, would not meet the exogenous criteria outlined above.

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[390] These requirements are similar to those set out in AGLGN, *Access Arrangements for NSW Gas Networks*, September 2000, p. 53.

[391] www.gasmarketco.com.au

EAPL would also be required to demonstrate that that FRC costs are of a significant magnitude and are not captured by other elements of total revenue. Moreover, as with the tax pass through mechanism it is considered appropriate that the FRC pass through mechanism is symmetrical and operates for both increases and decreases in costs.

In accordance with the above, the Commission requires the following amendment:

Amendment FDA 15

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 6.13 of the revised access arrangement to specify that:

- any new legal or procedural requirements related to FRC resulting from either: the introduction of a new law relating to retail contestability; stipulated in a direction of a relevant Minister; or stipulated by a body appointed to implement retail contestability in the gas industry;
- that the financial impact of the event must be of a pronounced magnitude; and
- the event must affect the company disproportionately.

EAPL must also amend clause 6.13 to allow for both positive and negative changes in FRC costs.

The Commission acknowledges the concern raised by ExxonMobil that FRC costs should be clarified to recover only those costs associated with a particular user. However, the Commission concurs with EAPL that it cannot reasonably pass on FRC costs associated with particular users given that FRC costs would generally relate to the whole system. The Commission also recognises TXU's concern that FRC costs are unlikely to be incurred given that FRC has already been implemented in NSW. However, as noted above, there exists the potential that new legal or procedural FRC requirements may be imposed in the future. In the event that this does occur, the above amendment requires EAPL to demonstrate the validity of any cost claims in its pass through statement.

For clarity, it is proposed that the financial impact of the pass through event must occur within the initial access arrangement period, and should not include any costs accepted under a previous pass through claim or already incorporated in approved regulated revenues (such as non capital costs). EAPL may specify that the financial impact of the event is ongoing through the period or represents a one off cost incurred in the relevant calendar year. This should ensure that reference tariffs are efficient (section 8.1(e)), that tariffs replicate the outcome of a competitive market (section 8.1(b)) and that investment decisions upstream and downstream are not distorted from an over or under recovery of costs (section 8.1(d)).

Amendment FDA 16

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clauses 8.7 and 6.13 to clarify that the financial impact of a pass through is incurred in the initial access arrangement period and that any claim does not include costs accepted under a previous pass through submission or in approved regulated revenues. Only the cumulative financial impact of a pass through may be claimed.

Elements of the pass through mechanism

Section 8.3A of the Code states that a reference tariff may vary within an access arrangement period only through implementation of the approved reference tariff variation method as provided for in sections 8.3B - 8.3H.

Sections 8.3B and C of the Code specify that upon the occurrence of the specified event the service provider must provide a notice to the regulator which explains the proposed variations in the reference tariff and explains how the specified event is consistent with the reference tariff variation method. In accordance with these provisions, the Commission considers that EAPL must provide a written notice to the Commission if a tax event occurs and has a financial impact on EAPL. This statement must specify: that a pass through event has occurred; the scope of the financial impact; how the claim meets the reference tariff policy; how EAPL intend to recover the pass through; and the effective date for variations. Tariff variations may involve a one off increase in tariffs or an amendment to the X factor over the remainder of the access arrangement period.

The Commission also considers that EAPL must submit a written notice to the Commission should there be an FRC event. As with a tax event, this notice should: specify the proposed cost claim; set out how the claim is consistent with the approach discussed above; and how EAPL intends to recover the costs. Clause 6.13 of EAPL's revised access arrangement is somewhat ambiguous as to whether EAPL intends to recover FRC costs through reference tariffs or as a separate reimbursement. As reimbursements are outside the scope of the Code, the Commission is of the view that it is appropriate for EAPL to recover any FRC costs through changes in reference tariffs. Accordingly, the Commission considers that clause 6.13 should be amended to clarify that FRC costs will be recovered through the reference tariff policy, and any reference to variations in the terms of the Transportation Agreement should be removed.

Section 8.3D(b) allows the Commission to propose a minimum notice period for the assessment of the variation to a reference tariff. The Commission acknowledges TXU's request that any pass through proposal made by EAPL involve consultation with affected users prior to approval.[392] The Commission agrees that it should have the opportunity to conduct a process of public consultation in response to proposals under the pass through mechanism. However, EAPL's proposal makes no allowance for such a process and does not propose a timeframe for assessment of any pass through claim. Accordingly, the Commission proposes to adopt a 40 business day assessment period for any pass through claim submitted by EAPL. In accordance with clause 8.3D of the

392 TXU submission, 23 August 2002, pp. 3-5.

Code, this period may be extended if the regulator seeks further information from the service provider.

Section 8.3B allows the Commission to specify the time within which the service provider must provide a notice to the regulator should a specified event occur. The Commission considers that for the purposes of administrative efficiency the frequency of pass through claims should be limited to one per year. Specifically, one pass through notice should be provided to the Commission at least 50 business days prior to the end of the calendar years 2004 through 2008. This notice may incorporate a number of pass through claims or may specify that no deemed events as specified in the reference tariff policy have occurred. Given a 40 day business assessment period, the submission of a notice on that date will ensure that the process corresponds with the annual price path approval process and that revised tariffs are finalised at least 10 business days prior to the start of the new financial year.

Should EAPL consider that the timing of the pass through notice places it at a financial disadvantage, it may request back payment of funds as well as an interest premium. EAPL must specify the date that the pass through event started to have a material impact and propose a method of compensation.

In accordance with section 8.3E of the Code, the Commission may notify EAPL prior to the due date that it does not approve a pass through claim, on the basis that it is inconsistent with the reference tariff variation method. The Commission may also specify a relevant variation that is consistent with the tariff variation method within the given time frame.

As provided under section 8.3H of the Code, the Commission may grant an extension of the assessment period on application by EAPL, or may extend the time period should it propose its own revisions in accordance with section 8.3G of the Code.

In the event that a pass through occurs but is not reported by the service provider, the Commission considers that it should be able to initiate a pass through review and amend tariffs accordingly. Such a provision is allowed for under section 8.3G of the Code, and may be appropriate given the absence of an incentive for a service provider to report a pass through event that will lead to decreases in reference tariffs.

Accordingly, Commission requires that the following amendment be introduced by EAPL to incorporate the above elements.

Amendment FDA 17

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 6.13 of its revised access arrangement to specify that the financial impact of FRC can only be recovered through reference tariffs. EAPL must also remove from clause 6.13 any reference to variations of the terms of Transportation Agreements.

In addition, EAPL must amend clauses 8.7 and 6.13 of its revised access arrangement as follows:

- EAPL must provide a written notice to the Commission specifying that a pass through event has occurred, the scope of the financial impact, how the claim is consistent with the pass through mechanism, the proposed variations to the reference tariff and an effective date for the changes.

- EAPL must provide for a minimum 40 day assessment period for any pass through claims submitted to the Commission. This period may be extended by the Commission should it seek further information from EAPL.
- EAPL must submit only one pass through notice a year, which must be submitted at least 50 days prior to the end of each financial year. This notice may incorporate a number of pass through claims or may specify that no specific events defined in the reference tariff policy have occurred.
- EAPL must state that it can apply for an extension of the relevant assessment period and that the Commission may extend the time period in the situation that it has proposed its own revisions to reference tariffs.
- EAPL must specify that the Commission can initiate its own pass through review.

In general, the Commission considers that the service provider must provide detailed documentary evidence in support of any pass through claim. The provision of this information is required for the Commission to adequately analyse and specify its reasons for allowing or disallowing a variation of the reference tariff under section 8.3F of the Code and undertake public consultation. Unless demonstrated that the information will be harmful to the legitimate business interests of EAPL, a user or prospective user, any information provided to the Commission will be considered by the Commission to be public information. The Commission therefore requires the following amendment.

Amendment FDA 18

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clauses 6.13 and 8.7 to state that EAPL must provide the Commission with documentary evidence (if available) which substantiates the financial impact of the pass through event. EAPL must use best endeavours to ensure that such information is available to the Commission.

2.10.2 Minimum distance on lateral tariffs

2.10.2.1 Original access arrangement

In its original access arrangement, EAPL proposed a cap on tariffs charged on lateral pipelines. Specifically, lateral tariffs would only apply to the first 100 km of any lateral pipeline. The mainline reference tariff would apply to the remaining length of the lateral pipeline.

2.10.2.2 Commission's Draft Decision

The Commission accepted EAPL's proposal in the *Draft Decision*. This was based on the Commission's understanding that excessive lateral tariffs may discourage lateral users, and any decline in volumes from the system may lead to an increase in tariffs for mainline users.

2.10.2.3 Submissions in response to the Draft Decision

No comments were received from interested parties on this issue.

2.10.2.4 Revised access arrangement

Unlike the original access arrangement, EAPL has not explicitly proposed a cap on lateral tariffs. However, EAPL has kept open the option of a minimum deemed distance in its documentation. Specifically, clause 7.5 of EAPL's revised access arrangement states that EAPL may, after consultation with the regulator, elect to specify that tariffs on the regional laterals will be calculated on the basis of a deemed minimum distance.

2.10.2.5 Submissions in response to the revised access arrangement

No comments were received from interested parties on this issue.

2.10.2.6 Commission's considerations

Under the Code, EAPL's proposal to implement a cap on lateral tariffs can be described as a reference tariff control formula approach. Such an approach represents a reference tariff variation method where an initial set of reference tariffs may vary over the access arrangement period in accordance with a specified formula or process.

As with the pass through mechanism discussed above, section 8.3 of the Code (which specifies that the manner in which a reference tariff may vary within an access arrangement period must be consistent with the objectives contained in section 8.1) also applies to a reference tariff control formula approach. Accordingly, the Commission must be satisfied that clause 7.5 of EAPL's revised access arrangement is consistent with the Code's reference tariff principles.

The Commission is of the view that the proposal put forward by EAPL in clause 7.5 may not be contrary to section 8.1. As discussed above and also in the *Draft Decision*, a minimum deemed distance for lateral tariffs may not represent a cross-subsidy given the complexities of tariff pricing. However, it considers that should EAPL wish to introduce a minimum distance for lateral tariffs, it must set out in its notice to the Commission the actual distance requested and demonstrate that this request complies with the section 8.1 principles. For example, it must be demonstrated that any proposal promotes the efficiency in the level and structure of the reference tariff (section 8.1(e)) and replicates the outcome of a competitive market (section 8.1(d)).

In addition, as with the pass through mechanism, this proposal must comply with sections 8.3-8.3H of the Code which relate to the reference tariff variation methodology. In particular, any request for a change in the deemed minimum distance of regional lateral tariffs must:

- be specified in a notice to the Commission (section 8.3B(b)) which contains the proposed variations to the reference tariff, an explanation of how the variations are consistent with the reference tariff variation policy and an effective date for the changes (section 8.3C);
- not take effect until 40 business days after the date of the notice by EAPL (as proposed for pass through events in accordance with section 8.3D);

- permit the regulator to disallow a variation of the reference tariff by notice to EAPL prior to the variation coming into effect (section 8.3E). This notice must set out its reasons for its decision and may specify any variation required by the regulator (section 8.3F); and
- allow the regulator to request additional information from EAPL and extend the assessment period accordingly (section 8.3D), and allow the regulator to grant extensions at any time period in section 8.3B to 8.3G that applies to EAPL (section 8.3H).

The Commission therefore requires the following amendment to clause 7.5 of the revised access arrangement in order to comply with the provisions of the Code.

Amendment FDA 19

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 7.5 to state that EAPL will:

- Provide a written notice to the Commission specifying the minimum distance for the calculation of lateral tariffs and demonstrate how this policy complies with section 8.1 of the Code.
- Provide for a minimum 40 day assessment period by the Commission which may be extended by the Commission should it seek further information from EAPL.
- Specify that the proposed changes will be deemed approved within the variation period, unless the Commission notifies EAPL that is does not approve the pass through claim or proposes a relevant variation to the proposal.
- State that it can apply for an extension of the relevant assessment period and that the Commission may extend the time period in the situation that it has proposed its own revisions to reference tariffs.

2.11 Incentive mechanisms

One of the primary benefits of a general price path approach or CPI-X mechanism as proposed by EAPL is that it should provide incentives for the service provider to reduce costs and allocate resources efficiently. This section will assess the details of this approach and will recommend a number of adjustments in light of new research in the area of benefit sharing.

2.11.1 Code requirements

Section 8.44 of the Code states that the reference tariff policy should, where the regulator considers it appropriate, contain a mechanism to enable a service provider to retain all or part of any returns which exceed the level expected for a specified period, particularly where these increased returns are due to the service provider's efforts. The Code provides that an incentive mechanism can operate within an access arrangement period or over two or more periods.

Section 8.45 provides that the incentive mechanism may:

- specify that tariffs be based on forecast variables regardless of the realised values;
- set a target revenue and specify how revenue in excess of this is to be shared between the service provider and users; and
- include a rebate mechanism for rebatable services that does not provide a full rebate to users.[393]

Section 8.46 states that an incentive mechanism should be designed to provide the service provider with an incentive to: increase the volume of sales; minimise the overall costs of providing these services; develop new services in response to market needs; and incur only prudent new facilities investment and non capital costs. In addition, section 8.46 requires that users and prospective users gain from efficiency improvements and improved volumes.

Section 8.2(d) of the Code specifies that an incentive mechanism can be incorporated in the reference tariff policy wherever the regulator considers it appropriate provided that it is consistent with the principles set out in section 8 of the Code.

2.11.2 Original access arrangement

In its original access arrangement, EAPL proposed an incentive mechanism offering three types of rebatable services as a means of promoting growth in gas transmission and increasing the utilisation of the MSP. EAPL also proposed a price path approach to setting reference tariffs which it submitted provided it with strong incentives to reduce costs and promote growth in gas transportation volumes. Specifically, EAPL proposed a CPI-X price path formula where reference tariffs for both mainline and laterals would follow a certain price path for the five year term of the initial access arrangement period.

2.11.3 Draft Decision

In the *Draft Decision*, the Commission noted that with the use of a price path EAPL may achieve returns greater than those implied by the WACC used to calculate the target revenues if actual volumes were greater than those forecast, costs were less than forecasts or capital expenditure was short of forecasts. The Commission considered that the retaining of returns greater than those forecast should provide an incentive as envisaged under the Code.

It was noted, however, that the tariffs proposed by EAPL were based on existing volume forecasts and did not take into consideration that lower tariffs approved by the Commission may lead to higher quantities demanded (depending on the price elasticities of gas transmission services). Accordingly, the Commission recognised that EAPL would retain the benefits of unanticipated revenue above forecasts that may eventuate from higher than forecast volumes.

With regard to rebatable services, EAPL submitted prior to the *Draft Decision* that circumstances had changed since the lodgement of the access arrangement which

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393 A rebatable service is defined in section 10.8 of the Code.

rendered the rebatable services unviable. The Commission supported EAPL's submission and proposed that the access arrangement be amended accordingly.

2.11.4 Submissions in response to the Draft Decision

There were no submissions made in response to the *Draft Decision* on these matters.

2.11.5 Revised access arrangement

In its revised access arrangement, EAPL proposed an incentive mechanism to operate during the initial access arrangement period. As discussed above, EAPL proposed a price control formula in the form of a CPI-X mechanism whereby reference tariffs for both mainline and lateral pipelines will follow a certain path set in advance for the length of the access arrangement period. EAPL stated that this price path approach to setting reference tariffs will:[394]

- enable it to develop the market for the reference service and other services in an environment of pipeline competition;
- provide it with an incentive to increase the volume of sales and minimise the cost of providing services; and
- allow it to share the benefits of increased efficiencies with users and prospective users in the subsequent access arrangement period.

2.11.6 Submissions in response to the revised access arrangement

There were no submissions made in response to the revised access arrangement on this issue.

2.11.7 Commission's considerations

Limitations of the incentive mechanism as applied to EAPL

EAPL has proposed a P_0 incentive mechanism in its revised access arrangement. Under a CPI-X price path, a P_0 mechanism may be viewed as the default incentive mechanism option. With this approach the service provider retains any unanticipated cost savings that are incurred within the access arrangement period. In general, increased costs experienced would also be borne by the service provider. At the conclusion of that period, no cost savings or additional costs are carried forward into the subsequent period. That is, the benefit (or cost) arising in the previous period are passed onto users.

As a result, the incentive of a P0 mechanism is, in general, for a service provider to achieve efficiencies early in a regulatory period as it is able to capture those savings for the maximum amount of time. As the conclusion of the regulatory period draws nearer,

[394] EAPL revised access arrangement information, 7 July 2003, p. 6.

the service provider's incentive to achieve savings declines as the period in which to capture these savings is shorter.[395]

In its revised access arrangement information, EAPL make a number of claims with regard to its price path incentive regime. EAPL argue that the proposed price path approach will: provide it with an incentive to minimise costs; allow it to share the benefits of these efficiencies with users; and provide it with an incentive to increase the volume of sales and to develop the market.

The Commission has assessed these claims with reference to the contractual arrangements that EAPL has with Agility for the provision of pipeline services (the PMA). The Commission is of the view that there is limited scope for EAPL to improve operating and maintenance costs efficiencies (and share them with users) given that a large portion of operating costs are performed under the terms of the PMA. The PMA requires EAPL to pay Agility fees throughout the contract period, many of which are fixed for a specific period of time.

Consequently, the PMA generates outcomes that do not fully reflect the requirements of sections 8.44 and 8.1(f) of the Code, which state that the reference tariff policy should provide the service provider with incentives to reduce costs. In addition, EAPL's outsourcing arrangements with Agility substantially undermine the objectives of section 8.46(e) of the Code, which requires that an incentive mechanism be designed so that users gain from increased efficiency, innovation or volume of sales.

EAPL has claimed confidentiality over the PMA which the Commission accepts. Accordingly, the details of the PMA and its impact on the incentive structure proposed by EAPL cannot be disclosed here. Nevertheless, the Commission has carried out an assessment pursuant to the Code. These details are provided in confidential Appendix G of this *Final Decision*.

P_0 mechanism for encouraging efficiencies

As noted above, the nature of the PMA substantially limits the scope of the incentives for EAPL to reduce costs and improve productivity within the access arrangement period.

However, for those elements that are under the control of EAPL, the Commission considers that the P_0 mechanism may fail to provide the most appropriate mechanism for EAPL in accordance with Code requirements.

A P_0 mechanism represents one of a number of incentive mechanisms (or benefit sharing mechanisms) available to the service provider under a CPI-X regime. Other options available include:

- Glide path – under this option benchmarks in the subsequent period are determined based on forecast efficient costs and then altered to allow for any efficiency gains (or losses) achieved in the previous period. The efficiency gains (losses) are

[395] A discussion of this is provided in NERA, *Efficiency carryover design: A report for SPI PowerNet,* October 2002, p. 6 and also NERA/Brian Williamson, *Incentives and Commitment in RPI-X Regulation*, October 1997.

gradually reduced (increased) so that at the end of the period the benefits are passed onto users entirely.

- Rolling carryover – under this option the service provider keeps any unanticipated savings (losses) above forecasts for a pre-determined number of years, regardless of when the gains (losses) are actually achieved. These benefits (losses) are added to benchmark costs established for subsequent regulatory periods.
- Index-based regulation – under this option operating costs and/or tariffs are set on the basis of cost data exogenous to the firm. Under this approach, the service provider may keep any unanticipated efficiency gains indefinitely, or be subject to an earnings sharing mechanism or frequent regulatory resets where prices and benchmarks are re-evaluated.

These incentive based benefit sharing regimes have been implemented by several regulators in recent times. The glide path approach was proposed by the Commission in the *DRP* and was implemented in the SPI PowerNet Final Decision and was used to assess first period non capital costs achieved by GasNet.[396] A glide path was also implemented by the ESC with respect to non capital costs achieved by electricity distributors.[397] The rolling carryover mechanism was put in place by the ESC in 2000 for electricity distribution and in 2002 for gas distribution companies. The Commission also adopted the rolling carryover for future non capital cost gains that may be achieved by GasNet in its 2003-2007 access arrangement period.[398] The Commission has proposed a retail benchmarking approach to the setting of GSM Termination Services, and a move towards index-based approaches to regulation have recently been debated and discussed to some length.[399]

The tariff path-P_0 approach proposed by EAPL is a relatively simple mechanism which does not require the calculation of a carryover for the subsequent period. However, recent research has highlighted a number of problems with the P_0 approach (as well as other approaches such as the glide path) when actuals at the end of the period are used as the basis of future efficient non capital cost forecasts.[400] First, under a P_0 mechanism, there may not be an adequate incentive for the service provider to implement efficiency improvements, particularly at the end of the regulatory period when gains can only be kept for a short period of time. Second, there may exist an incentive for the firm to defer the implementation of productivity improvements given that it may be in the interests of the service provider in NPV terms to implement efficiencies once new (higher) prices are set by the regulator. Third, under a P_0

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396 ACCC, *Final Decision: GasNet* and ACCC*, Victoria transmission network revenue caps, 2003-2008,* December 2002.

397 ORG, *Electricity Distribution Price Determination 2001-2005 Volume 1*, *Statement of Purpose and Reasons,* September 2000.

398 ESC, *Final Decision: Review of gas access arrangements*, October 2002; ORG, *Electricity Distribution Price Determination 2001-2005 Volume 1, Statement of Purpose and Reasons,* September 2000. ACCC, *Final Decision: GasNet*.

399 ACCC, *Pricing Methodology for the GSM and CDMA Termination Services: Final Report*, September 2002.

400 For example, ESC, *Final Decision: Review of gas access arrangements*, October 2002 and NERA, *Efficiency carryover design: A report for SPI PowerNet,* October 2002.

approach actuals achieved by the service provider in the first regulatory period may not provide a useful guide to future costs facing the service provider. Finally, with a P_0 adjustment 100 per cent of any temporary efficiency gains achieved within an access arrangement period are retained by the firm, that is, users do not benefit at all from such behaviour.

These shortcomings with the P_0 approach (as well as other approaches including the glide path) prompted the Commission to examine in detail alternative benefit sharing options available under a CPI-X regime. This assessment led the Commission to adopt the rolling carryover mechanism for operating costs for the revised GasNet access arrangement. The rolling carryover mechanism represents one mechanism that overcomes the problems noted above with regard to the P_0 approach, and in particular provides constant incentives for efficiency-savings over time. The Commission considers that the rolling carryover approach provides a more appropriate incentive mechanism than a P_0 approach under the provisions of section 8.46 and 8.2(d) of the Code. Details of the operation of this mechanism can be found at Appendix H.

The P_0 mechanism was originally proposed by EAPL in 1999, at a time when much of the thinking on these issues was at an elementary stage. Given that the rolling carryover has not been raised previously with regard to the MSP and has therefore not been subject to public consultation, it would be inappropriate for the Commission to require a new proposal at this stage of the MSP approval process.

Accordingly, the Commission does not require EAPL to amend its proposed access arrangement to include a rolling carryover mechanism, even though it considers that such a proposal is more appropriate under the relevant Code provisions. However, the Commission is prepared to asses such a mechanism should EAPL propose one in its revised access arrangement in response to this *Final Decision*.

2.12 Cost allocation and tariff setting

2.12.1 Code requirements

Section 8.38 of the Code requires that, to the maximum extent that is commercially and technically reasonable, reference tariffs should recover costs directly attributable to the reference service and a fair and reasonable share of costs incurred jointly with other services. The Code (section 8.42) also requires that the recovery of a particular user's share of costs also follows these principles. These requirements must be met, regardless of the methodology used to calculate total revenue. In addition, the Code requires the regulator to take into account the principles set out in section 8.1 of the Code and the elements in section 2.24 which include amongst other things the service provider's legitimate business interests, the interests of users, and the public interest.

An exception to the broad section 8 principles is the case of prudent discounts. If a user or prospective user would not be a user at the reference tariff, the Code (section 8.43) allows for a lower tariff to be charged (that is, a prudent discount to be given) to that user with the shortfall in revenue met by higher tariffs for other users. This is conditional on the prudent discount not causing tariffs to other users to be higher than they would have been if the potential user in question was not a user.

2.12.2 Original access arrangement

In its May 1999 access arrangement, EAPL proposed two reference services: the firm transportation service (the FT service) and the small take-off point service (the STP service). For cost allocation and tariff-setting purposes it was proposed that all revenue requirements would be allocated to the FT service and all STP capacity and throughput requirements be treated as FT requirements. Class STP tariffs would then be derived from the resulting Class FT tariffs. EAPL proposed this simplistic approach, because of the anticipated small proportion of total revenue (less than 1.0 per cent) expected to accrue to STP services.

EAPL proposed a three step methodology to cost allocation:

- segregate the pipeline into 'mainline' and 'laterals' for tariff-setting purposes;
- distinguish between fixed and variable costs; and
- allocate fixed costs to a capacity reservation charge and variable costs to a throughput charge.

The proposed categorisation of pipeline segments between mainline and laterals was as follows:[401]

- mainline: Moomba to Young, Young to Wilton and Young to Culcairn; and
- laterals: Young to Lithgow, Junee to Griffith, and Dalton to Canberra.

EAPL's rationale for this segregation was that the two groups of pipelines have substantially different size characteristics in diameters, economies of scale and markets. EAPL proposed to adopt a reference tariff structure with higher charges for laterals than the mainline. EAPL considered that this reflected higher per unit costs on the laterals. In support of its proposal to include the Young to Culcairn segment as part of the mainline rather than as a lateral, EAPL noted that the Young to Wagga segment had once served the function of a lateral, delivering gas to regional centres only. However, following construction of the Interconnect, the function of the segment changed with the lateral facilitating the linkage of the NSW and Victorian transmission systems to new sources of gas supply and new markets.'[402]

The reference tariffs proposed were structured around tariff components that reflected the length of pipeline (distance) and the quantity transported (service requirements). EAPL argued that such an approach was more cost reflective than zonal or postage-stamp rates and would not create artificial by-pass opportunities at zone boundaries. EAPL added that a distance based structure would be readily accommodated on the MSP because it had relatively few receipt and delivery points. The proposed tariffs were also structured so that fixed costs were recovered through capacity charges and variable costs by throughput charges. That is, EAPL proposed what is known as a two-part tariff.

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401 EAPL access arrangement information, 5 May 1999, pp. 45-46. The proposed segregation of the system into mainline and laterals for tariff charging purposes would represent a departure from EAPL's existing third party access policy under which no distinction is made.

402 EAPL response to submissions, 17 August 2000, p. 9.

A number of cost allocators were used to determine the proportion of total costs to be allocated between the mainline and laterals and to classify costs into fixed costs and variable costs. With regard to the mainline:lateral split, EAPL proposed to allocate capital costs on the basis of each pipeline's relative share of the ORC value of the MSP. Using this methodology, EAPL estimated that the mainline accounted for 90.45 per cent of total asset value and the laterals the remaining 9.55 per cent. EAPL considered that the allocation of costs on the basis of ORC rather than DORC would avoid potential distortions caused by varying ages of assets. EAPL proposed the allocation of non capital costs between mainline and laterals on the basis of pipeline length resulting in 88 per cent of costs being allocated to mainline and 12 per cent to laterals. With regard to the fixed:variable split, EAPL allocated all capital costs as fixed and proposed to allocate non capital costs by apportioning some of the costs as variable and others as fixed. The ratio of fixed to variable costs varied depending on the cost category. This allocation meant a capacity:throughput split of 94 per cent:6 per cent for the mainline and 93 per cent:7 per cent for the laterals.

EAPL submitted that it would not set tariffs strictly in accordance with the cost allocation proposed, noting that if tariffs were based on a rigid application of the allocation of total revenue, the impact on transportation costs to users on the laterals would be excessive and may cause economic hardship to some rural industries and customers. In view of this, EAPL proposed to cap the lateral charges and to phase in lateral tariffs progressively over the access arrangement period. Under the cap on lateral tariffs, lateral reference tariffs would only apply to the first 100 km of any lateral pipeline. The mainline reference tariff would apply to the remaining length of the lateral pipeline.[403]

As a consequence of the cap and the phasing in of lateral tariffs, it was calculated that lateral tariffs would under recover costs by 3.7 per cent. EAPL proposed to re-allocate this under recovery to mainline tariffs. EAPL did not consider that such a cost re-allocation from laterals to mainline was necessarily evidence of cross subsidisation. Moreover, EAPL argued that the gas hauled through the laterals served to reduce the mainline tariff, which would be higher in the absence of the lateral pipelines.[404]

2.12.3 Submissions in response to the original access arrangement

In its submission Incitec disagreed with EAPL's proposal to place a cap on lateral charges and noted this would result in a re-allocation of 3.7 per cent in total revenue from the laterals to the mainline reference tariff. The reasons put forward by Incitec for this position were:

- that the fundamental principle of 'user pays' should underlie a tariff setting mechanism and thus it is inappropriate for Sydney customers to subsidise assets for which they do not use;

[403] For example, a user at Orange would pay the mainline tariff from Moomba to Young (1 033 km) the lateral tariff for the first 100 km from Young to Orange, and the mainline tariff for the remaining distance (38 km).

[404] EAPL response to submissions, 17 August 2000, p. 9.

- that the subsidy is called for only because of the method of asset valuation and the high rate of return (8.4 per cent) proposed which combine to produce a revenue requirement so high that the market cannot meet it; and
- that while investment in the regional laterals may have been made on a reasonable basis at the time they were built, if they are no longer justifiable it may only be because of an unrealistic revenue expectation which flows from an overvalued asset.[405]

Incitec also questioned the classification of the Young to Culcairn pipeline as a mainline, because relative to the Moomba to Wilton mainline, it is much smaller and has a smaller flow. Incitec argued that this classification may mean that the segment received a subsidy from the mainline. It was also noted that the provision of capital for compression on the line was an area of concern.[406]

In a submission produced by NERA on behalf of Incitec, it was argued that EAPL's proposal to rebate 75 per cent of rebatable (discretionary) sales to eligible firm users, keep 10 per cent and divert 15 per cent to a 'depreciation reserve' was not justified. NERA stated that in essence EAPL would act as a banker for eligible users' funds, which was not appropriate. NERA also raised concern with the backhaul charged proposed by EAPL. It was argued that a charge based on 50 per cent of the capacity charge appeared excessive, given that apart from administrative costs, there are no other costs directly related to backhaul transactions.[407]

2.12.4 Commission's Draft Decision

Mainline and lateral split

In the *Draft Decision*, the Commission agreed with the methodology of applying a higher tariff on laterals compared to the mainline, as on the whole these pipelines had higher unit costs than the mainline. The Commission noted, however, that such an allocation methodology is only an approximation, given that particular pipelines within each class of asset may have different costs.

To assess the likelihood of the existence of cross-subsidies along pipeline segments, the Commission compared the incremental costs and stand alone costs of each pipeline segment (which define the lower and upper bounds in assessing cross-subsidies) with each segment's contribution to total revenue requirements of the system. This analysis found that tariffs on the Dalton to Canberra lateral were in excess of stand alone costs (as defined by DORC plus operating and maintenance costs), exposing the Dalton to Canberra lateral to the prospect of uneconomic by-pass. The Commission noted tariffs on the Dalton to Canberra lateral should be no higher than the tariffs that would be derived by applying a value to the pipeline equivalent to DORC plus non capital costs. The Commission proposed an amendment to this effect.

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405 Incitec submission, 24 September 1999, pp. 1-2.

406 Incitec submission, 24 September 1999, p. 2.

407 NERA, *Comments on East Australian Pipeline Limited Access Arrangements On Behalf of Incitec Ltd,* 23 January 2001, pp. 11-12.

Capacity and throughput charges

As noted above, EAPL's original proposal to separate charges for capacity and throughput can be viewed as a two-part tariff. The Commission considered that the straight fixed variable (SFV) approach proposed by EAPL of allocating fixed and variable costs to the capacity and throughput charges respectively had close links with the economic criteria for efficient pricing. That is, linking the capacity charge with capital costs of the pipeline provides a meaningful guide for investment decisions, while linking quantity charges to variable costs provides appropriate signals for usage at the margin. The Commission therefore proposed to accept as reasonable EAPL's proposed approach of recovering its revenue requirements by a capacity charge and a throughput charge. The amendments proposed in the *Draft Decision* (in particular the reduction in capital costs) would have resulted in a capacity:throughput ratio of 92:8 for the mainline and 90:10 for the laterals.

Distance based pricing

EAPL's proposed charges for reference services were also linked to distance. In the *Draft Decision*, the Commission considered that charges based on a per kilometre approach provided a simple way of differentiating between customers that require transport along different segments of the mainline and lateral pipelines. In this case, the distance related charge as proposed by EAPL should be able to apportion costs appropriately among users.

Allocation of costs between reference and non-reference services

On the allocation of costs between reference and non-reference services the Commission noted that the prospective user may negotiate different terms and conditions, including tariffs, when its requirements and circumstances varied significantly from the services provided for in the access arrangement. The Commission went on to note that EAPL had not projected any revenue for negotiable services and accordingly had not allocated any costs to the service.

Phasing in of lateral tariffs and 100 km cap

The Commission noted that implementation of the proposals contained in *Draft Decision* with regard to EAPL's concerns regarding the price shock lateral users face if tariffs were not phased in would have significantly reduced EAPL's revenue requirements and the overall tariffs faced by users of the MSP. The Commission went on to observe that these reductions would largely alleviate the problems identified by EAPL that lateral tariffs based on full cost recovery would be excessive. As to the proposed phase in mechanism, the Commission considered it was appropriate that where possible service providers should be able to earn a commercial return on each segment of their investment. The Commission added that lower earnings on particular classes of assets may discourage investment in infrastructure segments or regions. The Commission therefore proposed an amendment to remove the lateral tariff phase-in mechanism.

The Commission also considered EAPL's proposal to impose a 100 km cap on lateral tariffs to avoid substantial tariff increases for lateral users distant from the mainline. The Commission noted that application of the Commission's proposed revenue requirements contained in its *Draft Decision* would have reduced but not removed these increases. In the absence of the lateral users, mainline users would have experienced an increase in tariffs. It was not clear to the Commission that this approach represented a cross-subsidy from mainline users to lateral users. The Commission therefore proposed to accept EAPL's proposed 100 km cap on lateral tariffs for the initial access arrangement period.

2.12.5 Submissions in response to the Draft Decision

Responding to the *Draft Decision* DEI noted that while the approach of subjecting laterals to higher distance based charges may appear reasonable, such an approach would actually have the effect of imposing greater price reductions for those areas served by more than one pipeline, and the least price reductions for destinations that are served by one. DEI asserted that this outcome appeared to be at odds with the regulatory model which involves 'regulatory intervention where there is a genuine monopoly, and regulatory forbearance when competitive discipline is evident'.[408]

The PIAC also raised concerns with the proposal to have a different tariff structure for the lateral pipelines that would only apply for the first 100 km of the lateral. The PIAC noted that while the cap may prevent price shocks, large users have the ability to determine the location of their business operations. The PIAC also expressed concern with the apparent shift in costs from residential users because they use more of the infrastructure, when in fact they generally use less of the overall volume of the pipeline than small users.[409]

AGLWG proposed that there be a single distance based tariff for the entire pipeline system, provided that such an approach would not generate reference tariffs that are below incremental costs or exceed stand alone costs. AGLWG argued that the benefits of such a proposal included: no price shocks for users, simplicity, ease of administration, ease of marketing services, assistance in regional development and increased penetration of gas in country areas which would increase the contribution towards the cost of laterals. AGLWG added, however, that new laterals should be subject to an appropriate reference tariff.[410]

In its response to the *Draft Decision* EAPL agreed with the Commission that reference tariffs for any pipeline segment should not be based on an asset base higher than DORC plus operating and maintenance costs, and accordingly agreed with the Commission's amendment with regard to the Dalton to Canberra lateral. EAPL also agreed with the Commission's proposal to dispense with the phasing-in of lateral tariffs, as the new single distance-based tariff structure would not lead to tariffs that would generate price shocks.[411]

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[408] DEI submission 9 February 2001, pp. 5-6.

[409] PIAC submission, 12 February 2001, p. 2.

[410] AGLWG submission, 28 February 2001, p. 2.

[411] EAPL response to the Draft Decision, 14 March 2001, p. 23.

2.12.6 Revised access arrangement

In its revised Access arrangement, EAPL put forward a cost allocation methodology broadly consistent with its original access arrangement. EAPL has proposed that costs be allocated along two pipeline sub-systems, that is:

- the mainline which consists of the Moomba to Wilton pipeline, the Wagga Lateral, the Interconnect and the Canberra Lateral;
- the regional laterals consisting of the Northern Lateral (from Young to Lithgow including Bathurst, Orange and Oberon) and the Griffith Lateral (from Burnt Creek to Griffith).

According to EAPL the categorisation of reference tariffs for these segments has been designed to recover all directly attributable costs and a proportion of shared costs allocated in proportion to the mainline and regional ORC.[412] The reference tariffs have been designed so that revenues for the regional laterals cover the incremental costs of the regional laterals.[413]

EAPL has proposed only one reference service, the Firm Service with all costs attributed to this service. The reference tariff for this service is divided into two components designed to broadly reflect the fixed and variable components of transportation costs on the MSP. Fixed costs are allocated to the capacity charge and variable costs are allocated to the throughput charge in the ratio 96:4 for both the mainline and laterals. This differs slightly from the 94.4:5.6 allocation for the mainline and the 93:7 split for regional laterals specified in the original access arrangement. EAPL did not recalculate the ratio of fixed to variable costs to achieve the new allocation, but employed the allocation that was implied in its current published tariffs.[414] Costs are further allocated along the pipeline on a distance basis to obtain tariffs in the form $/GJ/km. This is achieved by dividing the total forecast capacity-distance product and the throughput-distance product for the MSP in each year.

As with the initial access arrangement, EAPL has not projected any revenue for negotiable services and therefore has not allocated any costs to that service.

The revised access arrangement also proposed that EAPL may elect that the charges on regional laterals be calculated on the basis of a deemed minimum distance, after consultation with the regulator.[415]

Apart from capacity and throughput charges, EAPL has also proposed a number of other charges in its revised access arrangement. These are overrun charges, odorisation, balancing charges, daily variance charges and charges in respect of receipt points or delivery points. These charges are discussed in Chapter 3 of this *Final Decision*.

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412 EAPL revised access arrangement information, 7 July 2003, pp. 21-22.

413 EAPL revised access arrangement information, 7 July 2003, p. 5.

414 EAPL revised access arrangement information, 7 July 2003, p. 25.

415 EAPL revised access arrangement, 30 April 2002, p. 8.

2.12.7 Submissions in response to the revised access arrangement

As noted in section 2.9 TXU stated that it was difficult to provide a definitive response regarding EAPL's tariff proposals, given the lack of information. TXU in particular noted the significant increase in non capital costs and change in the depreciation approach proposed in the revised access arrangement.[416]

2.12.8 Commission's considerations

Segregation of pipelines into mainline and lateral

The Commission maintains its position established in the *Draft Decision* that the segregation of pipelines into mainline and laterals for cost allocation purposes is appropriate. This is because the lateral segments have higher unit costs than the mainline, and it is therefore reasonable that tariffs reflect these differing cost structures.

As noted above, DEI raised concern with subjecting laterals to higher charges as it has the effect of imposing greater price falls for those areas served by more than one pipeline. The Commission, however, does not consider that the pricing pattern observed by DEI is inappropriate. In a competitive market, those services subject to the greatest market pressures are likely to exhibit the most substantial price reductions, and it would be expected that tariffs would be highest for those pipelines that have the highest costs and lowest volumes.

In the *Draft Decision* the Commission noted that the broad classification of the pipeline system into only two pipeline categories may have cross-subsidy implications, as different pipeline segments within each category may have substantially different cost characteristics. The Commission consequently assessed incremental and stand alone costs for each of the pipeline segments, and concluded that tariffs on the Dalton to Canberra lateral would be in excess of stand alone expenses which was not appropriate. EAPL has since incorporated the Dalton to Canberra lateral as part of the mainline for tariff setting purposes. The Commission is of the view that this new classification is appropriate as it should mitigate against any cross-subsidies within the MSP system and should comply with the provisions set out in section 8.38 relating to the allocation of costs.

In addition, the Commission considers that the segregation of pipelines into mainline and laterals for cost allocation purposes meets the objectives of section 8.1 of the Code. In particular, the separation of tariffs should promote efficiency in the level and structure of reference tariffs (section 8.1(e)), should better reflect outcomes expected from a competitive market (section 8.1(b)) and should provide appropriate signals for upstream and downstream investment decisions (in accordance with section 8.1(d) of the Code).

Capacity and throughput split

EAPL proposed in its revised access arrangement to implement separate charges for capacity and throughput. As proposed in the initial access arrangement, the capacity reservation charge reflects the forecast MDQ of capacity specified within

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416 TXU covering letter, 18 August 2002, p. 2.

Transportation Agreements and the pipeline distance from the receipt point to the delivery point, while the throughout charge is based on the actual quantity of gas to the user on that day and also the pipeline distance.[417] The Commission maintains that this two-part tariff approach to cost allocation is reasonable. Such a tariff structure should promote efficient outcomes given that users are required to pay their proportion of the maximum capacity demanded on the system. The tariff structure should also encourage users to improve load factors given that the throughput charge is minimal compared to the capacity charge. EAPL's proposal to allocate costs based on distance between receipt and delivery points is also considered reasonable, given that it provides a simple method to allocate costs between different distance based services offered by the pipeline.

As in the original access arrangement, EAPL has proposed to allocate pipeline costs between capacity and throughput based broadly on whether they are fixed or variable costs. However, unlike the original access arrangement, EAPL has not sought to recalculate the ratio of fixed to variable costs but has instead used the 96:4 split implied in current published tariffs. EAPL stated that it is reasonably confident that, if recalculated, the ratio would show a higher proportion of fixed costs than 96 per cent, but noted that users generally have a preference for throughout charges rather than capacity charges as this reduces the costs associated with unutilised capacity reservation.[418]

The Commission is of the view that the cost allocation estimates proposed by EAPL between throughput and capacity are reasonable. It is recognised that the allocation of these costs is a difficult and arbitrary process that requires an element of judgement. Moreover, the Commission is of the view that the cost allocation methodology proposed by EAPL complies with the requirements set out in section 8.1 of the Code. Specifically, the allocation should broadly ensure efficiency in the structure of the reference tariff (section 8.1(e)) and should not distort investment decisions in pipeline systems or in upstream or downstream industries (section 8.1(d)).

Allocation of costs between reference and non-reference services

In its revised access arrangement EAPL proposed to remove the STP services and offer only one reference service to users. The Commission considers that this change to the initial access arrangement is reasonable given that, as argued by EAPL, the uptake of class STP services is likely to be negligible.

The revised access arrangement also proposed the removal of rebatable services, thus leaving only one type of non-reference service on offer: a negotiated service. As in the original access arrangement, EAPL has not projected any revenue for negotiable services and has accordingly not allocated any costs to these services.

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[417] EAPL revised access arrangement, 30 April 2002, p. 8 and EAPL revised access arrangement information, 7 July 2003, p. 26.

[418] EAPL revised access arrangement information, 7 July 2003, pp. 25-26.

Phasing in of laterals and price cap

In the revised access arrangement EAPL has proposed that initial reference tariffs on both the mainline and laterals for the access arrangement period be based on MSP published tariffs. EAPL also proposed the introduction of a positive X factor of 4 per cent per year in the first access arrangement period for the laterals, which effectively means that lateral tariffs are phased in at a rate of 4 per cent each year in real terms.

As a result of proposals set out in this *Final Decision*, EAPL's revenue requirements are substantially reduced on both the mainline and lateral pipelines. In fact, as discussed in section 2.9, the Commission's calculations suggest a positive X factor of 0.38 per cent on laterals, suggesting price decreases in real terms over the course of the access arrangement. Since this tariff path effectively allows EAPL to recover costs at the outset on the lateral pipelines, the Commission is of the view that such a proposal complies with section 8.38 of the Code and should promote efficient investment decisions and efficiency in the level and structure of reference tariffs (sections 8.1 (d) and (e)).

EAPL has proposed in the revised access arrangement that it may elect that charges on regional laterals be calculated on the basis of a deemed minimum distance, after consultation with the regulator (clause 7.5 of the revised access arrangement).[419] In its initial access arrangement, EAPL proposed to implement a 100 km cap on lateral tariffs to avoid substantial tariff rises for lateral users distant from the mainline. While such an approach may appear to represent a departure from cost-reflective pricing, the Commission accepted EAPL's proposal in the *Draft Decision*. This was based on the Commission's understanding that excessive lateral tariffs may discourage lateral users, and any decline in volumes from the system may lead to an increase in tariffs for mainline users.

As noted above, amendments contained in this *Final Decision* will generate a decline in lateral tariffs from current published tariffs in real terms across the access arrangement period. Given this, it would be highly unlikely for EAPL to elect that charges on regional tariffs be subject to a minimum distance requirement. Notwithstanding this, the Commission considers that the arguments relating to laterals proposed in the *Draft Decision* are still valid. That is, a minimum distance cap on tariffs may not constitute a cross-subsidy given the complexities associated with network pricing.

Accordingly, it is considered that EAPL may provide a notice to the Commission requesting a deemed minimum distance for lateral tariffs within the access arrangement period. The details of the Commission's acceptance of this proposal are outlined in the section 2.10 of this *Final Decision*.

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419 EAPL revised access arrangement, 30 April 2002, p. 8.

2.13 Compliance with tariff principles

2.13.1 Code requirements

Section 3.3 of the Code requires an access arrangement to include a reference tariff for at least one service that is likely to be sought by a significant part of the market and any other services for which the regulator considers a reference tariff should be included. Section 3.5 of the Code requires an access arrangement to include a policy describing the principles that are to be used to determine a reference tariff (a reference tariff policy). This reference tariff policy must, in the regulator's opinion, comply with the reference tariff principles set out in section 8 of the Code.

In accordance with section 8.1 of the Code the reference tariff policy and reference tariffs should be designed to achieve a number of objectives including:

a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of 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.

In addition, section 8.2 stipulates that when approving a reference tariff and reference tariff policy the regulator must be satisfied that:

a) the revenue to be generated from sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in section 8;

b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of total revenue that a reference tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in section 8;

c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in section 8;

d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in section 8; and

e) any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

The reference tariff principles outlined in section 8.1 and 8.2 are designed to provide flexibility so that reference tariffs and reference tariff policies can be designed to meet the specific needs of each pipeline. However, the objectives set out in section 8.1 may, at times, conflict with each other. On these occasions the regulator must determine how the conflict will be reconciled by reference to the factors in section 2.24 of the

Code. Section 2.24 of the Code states that in assessing a proposed access arrangement, the regulator must take the following into account:

a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

d) the economically efficient operation of the Covered Pipeline;

e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

f) the interests of Users and Prospective Users; and

g) any other matters that the Relevant Regulator considers are relevant.

The Epic Decision provides further guidance as to the appropriate application of section 8.1 and 2.24 by a regulator. In that decision the Court of Appeal stated:

> ... The last paragraph of s8.1 recognises that the objectives of (a) to (f) in s8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s8.1 itself. Of necessity, the Regulator must have guidance outside of s8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s8.1 the Regulator should take into account the factors in s2.24(a) to (g).[420]

2.13.2 Commission's considerations

While EAPL has, as required by sections 3.3 and 3.5, included a reference tariff and a reference tariff policy in its proposed access arrangement, its proposed tariff and tariff policy do not, in the Commission's opinion, comply with the reference tariff principles described in section 8 of the Code.

Each aspect of the reference tariff and reference tariff policy are assessed in the relevant sections of this *Final Decision.* In undertaking this assessment the Commission has had recourse to the relevant provisions of the Code and to the objectives set out in section 8.1 of the Code. In instances where the Commission has been unable to resolve conflict between the objectives in section 8.1 it has been guided by the criteria set out in section 2.24 of the Code.

As a result of this assessment the Commission requires a number of amendments to be made to EAPL's proposed ICB, non capital costs, rate of return, forecast volumes, economic depreciation charges, total revenue and tariff path for both the mainline and regional laterals. For the reasons set out in this *Final Decision*, the Commission

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420 [2002] WASCA 231, par 85.

considers that the adoption of these amendments will result in a closer alignment of the reference tariff and reference tariff policy with the principles set out in section 8.1 of the Code.

With regard to section 8.2, there are five factors about which the Commission must be satisfied in determining whether to approve a reference tariff or reference tariff policy.

Total revenue is established consistently with the principles and according to one of the methodologies contained in section 8 of the Code (section 8.2(a))

EAPL has proposed the use of the NPV methodology applied on a real basis to determine its total revenue over the expected life of the MSP. This approach is permitted by section 8 of the Code. The Commission, however, considers that EAPL's proposed ICB, non capital costs and rate of return are overstated and as a result of amendments contained in this *Final Decision* the approved revenue stream will be less than that proposed by EAPL.

The proportion of total revenue that any one reference tariff is designed to recover is calculated consistent with the principles of section 8 of the Code (section 8.2(b))

EAPL has proposed only one reference service, the Firm Service, and for tariff setting purposes has allocated all costs and attributed all forecast volumes to this service. The Commission is satisfied that the allocation of capital and non capital costs to the single reference service is appropriate.

The proportion of total revenue recovered from users of a service is calculated consistent with the principles of section 8 of the Code (section 8.2(c))

The Commission is satisfied that the recovery of total revenue from mainline and lateral users is consistent with the principles set out in section 8 of the Code.

Incentive mechanisms that are incorporated are consistent with the principles of section 8 of the Code (section 8.2(d))

The Code states that an incentive mechanism may include, amongst other things, a sharing between the service provider and users any revenue in excess of the target revenue. Whilst the Commission is satisfied that EAPL's proposed mechanism is consistent with sections 8.46 and 8.2(d) of the Code, it considers that the rolling carryover mechanism would result in a closer alignment with the principles of section 8.1 of the code. The Commission therefore encourages EAPL to adopt the rolling carryover mechanism in its initial access arrangement period and in subsequent periods.

Forecasts used are best estimates arrived at on a reasonable basis (section 8.2(e))

As a result of section 8.2(e), the Commission has specified a number of amendments to the forecast non capital costs, rate of return and volumes over the access arrangement period. The Commission considers that these amendments will result in reference tariffs being based on best estimates arrived at on a reasonable basis.

3. Non-tariff elements

Section 3 of the Code establishes the minimum contents of an access arrangement, which include the following mandatory non-tariff elements:

- a services policy that must contain at least one service that is likely to be sought by a significant part of the market;
- terms and conditions on which the service provider will supply each reference service;
- a capacity management policy stating whether the covered pipeline is a contract carriage or market carriage pipeline;
- in the case of a contract carriage pipeline, a trading policy which provides for the trading of capacity;
- a queuing policy which defines the priority that users and prospective users have to negotiate capacity where there is insufficient capacity on the pipeline;
- an extensions and expansions policy which determines whether an extension or expansion of a covered pipeline is to be treated as part of the covered pipeline for the purposes of the Code; and
- a date by which revisions to the access arrangement must be submitted and a date on which the revisions are intended to commence.

An access arrangement must also contain a reference tariff policy and at least one reference tariff. EAPL's tariff related proposals were assessed for compliance with the Code in Chapter 2 of this Decision. In this chapter the mandatory non-tariff elements of access to the MSP are assessed for conformance with the Code.

3.1 Services policy

3.1.1 Code requirements

Section 3.1 of the Code requires the inclusion of a services policy in an access arrangement. In accordance with section 3.2 the policy must include a description of one or more services that the service provider will make available to users and prospective users. The policy must contain one or more services which are likely to be sought by a significant part of the market and any service or services that in the relevant regulator's opinion should be included in the policy.

To the extent that is practicable and reasonable, a service provider should also make available only those elements of a service required by users and prospective users and apply a separate tariff for each element if requested.

3.1.2 Original access arrangement

EAPL's original service policy consisted of the following:

1. two reference services:
   - i) a firm transportation service (Class FT Service); and
   - ii) a small take-off point service (Class STP Service);
2. three rebatable non-reference services with biddable features:
   - i) winter season firm transportation service (Class WFT Service);
   - ii) off-season firm transportation service (Class OFT Service); and
   - iii) interruptible transportation service (Class IT Service); and
3. a negotiable non-reference service.

3.1.3 Commission's Draft Decision

In its consideration of EAPL's original proposal, the Commission considered whether the services policy adequately represented the services to be offered or whether other services should either be deleted from or added to the policy. On the inclusion of rebatable services within EAPL's services policy, the Commission examined concerns later raised by EAPL[421] and concluded that the most appropriate course of action would be to delete these services from the access arrangement (proposed amendment A3.1). Apart from this amendment the Commission determined that the requirements of sections 3.1 and 3.2 (i) of the Code had been otherwise met.

With respect to section 3.2(a)(i) the Commission determined that the proposed FT Service was one that was likely to be sought by a significant part of the market. In reaching this decision the Commission considered Boral's remarks that an amended IT Service be included in the reference service.[422] However, the Commission determined that this would be inappropriate given the excess capacity anticipated on the MSP during the access arrangement period, which would in effect make interruption of services unlikely.

3.1.4 Submissions in response to the Draft Decision

AGLWG supported the Commission's proposed amendment to remove the rebatable services from the access arrangement but suggested that an IT service be offered as a reference service on certain conditions including: the term of the service being a minimum of one month and a maximum of one year; the service be subject to capacity being available and to whole or partial interruption at any time; and the service being available at a premium to the FT reference tariff.[423] In relation to the negotiable service, AGLWG supported its inclusion and suggested that EAPL should be encouraged to provide a 'start up' tariff for a new industry.

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[421] EAPL letter to the Commission, 11 August 2000, p. 3.

[422] Boral submission, 2 July 1999, p. 2.

[423] AGLWG submission, 28 February 2001, p. 3.

While Origin Energy Pipelines (Origin) understood the reluctance of EAPL to offer an interruptible service when spare capacity exists, it was of the opinion that a more flexible firm service coupled with high overrun charges was needed than that proposed by EAPL.[424] Origin considered that without a more flexible service, small users and new entrants would face barriers to entry and high unit costs as they sought to grow their markets. Origin proposed that to a limited extent an IT service could supplement the proposed FT service. In relation to whether the IT service should be a rebatable service, Origin suggested that while spare capacity exists the service should not be a rebatable service because it would merely displace some of the volume that EAPL would otherwise sell as FT. Origin was, however, of the view that when the pipeline is operating at or near full capacity (470 TJ/d), the IT service should become a rebatable service.

Responding to the Commission's *Draft Decision*, EAPL agreed with the proposal not to include the three rebatable services in its services policy.[425] EAPL further advised that it proposed to remove the STP service from the access arrangement as it was unlikely that any user would seek the service.

On the issue of interruptible services, EAPL noted that such services are traditionally provided when the pipeline is at or near capacity and there is a real likelihood that the service provider will have to interrupt the service to ensure that it is able to satisfy the obligations to other users under firm transportation services. EAPL argued that given the current expected levels of capacity available on the MSP, there was no rationale for such a service to be offered. EAPL acknowledged that there may be some demand for a service with features similar to those provided by an interruptible service, for example a term of less than one year and a low load factor. However, EAPL is of the view that it is not necessary to offer a specific interruptible service, rather these features should be addressed in other ways. For example in the case of a term less than one year, EAPL proposed that an adjustment could be made to the tariff for the firm reference service.

3.1.5 Revised access arrangement

EAPL's revised service policy, consists of two services:[426]

1. a reference service for firm transport (Firm Service); and
2. a negotiable service with negotiable tariffs and negotiable terms and conditions, available in cases where a prospective user's requirements and circumstances vary from the conditions of a reference service and cannot be satisfied through a reference service (Negotiable Service).

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[424] Origin submission, 1 March 2001, p. 1.

[425] EAPL response to the Draft Decision, 14 March 2001, p. 25.

[426] Contained in section 5.1 of EAPL's revised access arrangement.

Reference Service - Firm Service

Details of EAPL's reference service policy and the reference tariffs applicable are set out in sections 6 and 7 and Attachments C1 - C6 of EAPL's revised access arrangement.

EAPL defines a Firm Service as a service which provides for the transportation of gas through any part of the pipeline in any direction. As a Firm Service, it is not subject to curtailment or interruption, except as set out in the access arrangement or the transportation agreement. The minimum term for the Firm Service is one year and the maximum term is 10 years.

The tariff for the Firm Service is determined on the basis of capacity, throughput and other charges (as set out in Attachment C5) including charges for overruns, odorisation, balancing, daily variance and charges in respect of receipt points or delivery points. Different tariffs apply depending on whether delivery points are on the mainline or laterals. In addition, provision has been made for the adjustment of tariffs under various scenarios of coverage such that tariffs will be adjusted to reflect the competitively derived price for gas transportation through segments of the pipeline where coverage has been revoked. The various scenarios of coverage are:

- all of the MSP is covered except the Moomba to Wilton pipeline and the Canberra lateral (Attachment C2);
- all of the MSP is covered except the Moomba to Wilton pipeline (Attachment C3); and
- all of the MSP is covered except the Canberra lateral (Attachment C4).

The daily capacity charge for a Firm Service is equal to the product of the capacity reference tariff, the pipeline distance from receipt point to delivery point and the maximum daily quantity (MDQ) specified in the Transportation Agreement. The capacity reference tariffs which will apply under various levels of coverage are detailed in Attachments C1 – C4. The pipeline distances for determining charges are specified in Attachment C6.

The daily throughput charge is equal to the product of the throughput reference tariff, the pipeline distance from receipt point to delivery point and the actual quantity of gas delivered to the user on that day. The throughput reference tariffs which will apply under various levels of coverage are set out in Attachments C1 – C4. The pipeline distances for determining charges are specified in Attachment C6.

In relation to capacity and throughput charges for delivery from regional laterals, EAPL may, after consultation with the regulator, elect to specify that these be calculated on the basis of a deemed minimum distance (clause 7.5). For backhaul services, users are entitled to a 50 per cent discount on the capacity charge and a waiver of the throughput charge.

3.1.6 Submissions in response to the revised access arrangement

No submissions were received in response to EAPL's revised service policy although some concerns regarding the prioritisation of services were expressed. These concerns are set out and discussed in the Terms and Conditions section of this chapter (section 3.2)

3.1.7 Commission's considerations

EAPL's revised services policy is substantially different from that contained in its original proposed access arrangement. Specifically, the Commission notes that EAPL is no longer proposing to offer either the STP Service or the three rebatable services, the latter of which is in accordance with the Commission's proposed amendment A3.1.

Examining the revised service policy, it appears that:

- the Firm Service proposed by EAPL is one which is likely to be sought by a significant part of the market; and
- the inclusion of the Negotiable Service provides users and prospective users with the ability to obtain only those elements desired at a negotiated tariff.

Accordingly, the Commission considers that the proposed services policy satisfies the requirements of sections 3.1, 3.2(a)(i), 3.2(b) and 3.2(c) of the Code.

As to whether an interruptible service should be included in the services policy, section 3.2(a)(ii) of the Code allows the relevant regulator to require the inclusion of any service or services which in its opinion should be included. This opinion will be formed with recourse to the factors set out in section 2.24 of the Code, which the relevant regulator must take into account when assessing a proposed access arrangement. Against this backdrop the Commission has examined the issues raised by AGLWG, Origin and EAPL regarding both the need for an interruptible service and in turn the need for the service where there is significant excess capacity.

Before commencing this examination it is relevant to consider the rationale for offering an interruptible service. An interruptible service is designed to provide services at a discounted rate which will be subject to interruption during periods of peak demand or in the event of emergencies. Clearly both users and the service provider will benefit from this service if the pipeline is operating at or near capacity and thus there is a clear rationale for offering such a service. In cases where there is significant excess capacity, however, the rationale for offering the service is absent. If there is limited risk of the service being interrupted users may be encouraged to opt for an interruptible service over a firm service. As set out in the *Draft Decision*[427], the pricing of an interruptible service below the level of a firm service could result in the service provider incurring an undue loss of revenue and being unable to cover its efficient costs. This result would not be in the service provider's legitimate business interests, contrary to section 2.24(a) of the Code.

AGLWG has suggested that this outcome could be overcome by charging higher tariffs for the interruptible service relative to the Firm Service.[428] Similarly, Origin has suggested that while spare capacity exists the interruptible service should not be a

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427 ACCC, *Draft Decision: MSP,* p. 141.

428 AGLWG submission, 28 February 2001, p. 3.

rebatable service.[429] These suggestions may operate to counter the attraction of an interruptible service over a firm service and in turn limit the effect upon EAPL's revenues and legitimate business interests.

While these solutions may alleviate some concerns the Commission has in relation to section 2.24(a), the Commission considers that given the significant excess capacity that is forecast to prevail on the pipeline over the initial access arrangement, it is clear that the rationale for offering an interruptible service is absent. Consequently, a decision by the Commission to require EAPL to provide the service could impinge upon EAPL's legitimate business interests (contrary to section 2.24(a)).

If, as EAPL suggests, the demand for an interruptible service stems not from the interruptible features of the service but rather from other features such as the term of the service and the low load factor, then it would appear that the interests of some users and prospective users would be better served through the unbundling of services. However, the Commission notes that the proposed Negotiable Service provides for the variation of terms and conditions, including the tariff, where a user's circumstances vary from the conditions of a reference service. On this basis it would appear that there is already a mechanism in place for users to obtain shorter term contracts or lower loads than provided for by the Firm Service. Thus it could be argued that the interests of users and prospective users are already being met by the more flexible Negotiable Service (section 2.24(e)).

The Commission therefore concludes that the inclusion of an interruptible service in EAPL's service policy is not currently warranted. However, if the pipeline approaches capacity in the next access arrangement period, it may come to a different view as to the suitability of the inclusion of such a service.

3.2 Terms and conditions

3.2.1 Code Requirements

Section 3.6 of the Code requires an access arrangement to include the terms and conditions upon which a service provider will supply a reference service. In accordance with section 3.6 of the Code, these terms and conditions must be reasonable. The question of what is reasonable is to be determined by reference to the factors in section 2.24 of the Code, as was confirmed by the Epic Decision.[430]

3.2.2 Original access arrangement

Details of EAPL's original proposal for the terms and conditions upon which it would supply reference services can be found in section 3.2.3 of the Commission's *Draft Decision*.

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[429] Origin submission, 1 March 2001, p. 1.

[430] [2002] WASCA 231, par 59.

3.2.3 Commission's Draft Decision

In its *Draft Decision* the Commission proposed a number of amendments to EAPL's terms and conditions including:

Proposed amendment A3.2 - requiring EAPL to specify that the access arrangement provisions prevail over the term sheets, standard service agreements, EAPL's nominations and balancing procedures and any other existing or future documents relating to the provision of access.

Proposed amendment A3.3 - requiring EAPL to delete clause 28.1(6) (this clause related to the grounds on which EAPL could withhold consent or give conditional consent to the transfer of receipt and delivery points).

Proposed amendment A3.4 - requiring EAPL to delete clause 28.1(5) (this clause stated that EAPL could make its consent to a transfer of a receipt or delivery point conditional on all users of the facility agreeing to share the facilities).

Proposed amendment A3.5 - requiring the amendment of the *Request for Transportation Services – Request Sheet* to include the option of multiple receipt and delivery points.

Proposed amendment A3.6 - requiring the inclusion of a provision that the proposed review of operational and balancing provisions and charges would be conducted within six months of approval of the access arrangement.

Proposed amendment A3.7 - requiring EAPL to amend the access arrangement to state that EAPL would, if recommendations by the AGA Gas Specification Working Group to adopt more flexible gas specifications in south-eastern Australia were approved, substitute that specification for the specification currently set out in Table A7.1 of Attachment 7 of the access arrangement, subject to obligations under existing service agreements.

Proposed amendment A3.8 - requiring EAPL to clarify the prudential requirements for users and prospective users.

3.2.4 Revised access arrangement

Pursuant to clause 5.3 of the revised access arrangement, EAPL proposes to provide the Firm Service under a transportation agreement on the terms and conditions consistent with the access arrangement including the principles set out in Attachment D. In addition to the provisions contained in Attachment D some terms and conditions can be found in Attachments E, F, G and within the body of the access arrangement.

3.2.5 Commission's considerations

In light of the number of revisions and additional terms and conditions contained in the revised access arrangement, the remainder of this section will be limited to assessing those provisions:

- in the original access arrangement which the Commission's Draft Decision proposed should be amended, or which were the subject of submissions following the Draft Decision, and which have been replicated in the revised access arrangement; and

- in the revised access arrangement which were either the subject of submissions by interested parties, or which the Commission considers should be examined.

Those provisions from the original access arrangement which have been replicated in the revised access arrangement can be found under the following broad headings: Status of the access arrangement and transportation agreement; Receipt and delivery points; Operational and balancing provisions; Gas quality; Prudential requirements; and Overrun charges.

In assessing these provisions, a summary of the Commission's proposed amendments will be provided followed by:

- an overview of submissions received in response to the Commission's Draft Decision;
- an outline of the relevant provisions contained in the revised access arrangement;
- an overview of submissions received following the revised access arrangement; and
- the Commission's considerations, which includes, where relevant, consideration of the factors set out in section 2.24 of the Code and amendments that the Commission proposes in order for the access arrangement to be approved.

Those provisions within the revised access arrangement which have not previously been the subject of the Commission's consideration and which were either the subject of submissions or which the Commission considers should be examined can be found under the following broad headings: Overrun charges; Liabilities and indemnities; Daily variance charges; Order of priority of service; Custody, control and title; Force majeure and capacity charge relief; Assignment; Insurance; System use gas; Gas pressures and temperatures; and Charges in respect of receipt or delivery points.

In assessing these provisions, an outline of the relevant provisions will be provided followed by:

- an overview of submissions received in response to the revised access arrangement; and
- the Commission's considerations, which include, where relevant, consideration of the factors set out in section 2.24 of the Code and amendments that the Commission requires in order for the access arrangement to be approved.

3.2.5.1 Status of the access arrangement and transportation agreement

Commission's Draft Decision

As mentioned previously, the Commission's *Draft Decision* proposed that EAPL amend its access arrangement to state that in the event of any inconsistency arising between the access arrangement and service agreements, the access arrangement should prevail over the standard service agreement and any other documents relating to the provision of access (proposed amendment A3.2).

EAPL's response to the Draft Decision

EAPL did not object to the Commission's proposed amendment to clarify that reference services would be provided on the terms and conditions of the access arrangement, and to clarify the priority of Attachments 3 and 4 over documents which were not part of the access arrangement.[431] However, EAPL considered that in light of its ability to negotiate different terms of access, it would not be appropriate for the access arrangement to mandate that Attachments 3 and 4 would prevail over any other agreements. EAPL further argued that it would be inappropriate for the Commission to require an amendment which would have the effect of requiring EAPL to act inconsistently with its rights and obligations under existing transportation agreements. EAPL therefore rejected the Commission's proposed amendment.

Revised access arrangement

Clause 5.3 states that EAPL will provide the Firm Service under a transportation agreement on terms and conditions consistent with the access arrangement including the principles for terms and conditions set out in Attachment D.

Commission's considerations

The Commission has examined the arguments from EAPL and agrees that EAPL's contentions are reasonable as they relate to negotiated services and services supplied pursuant to an existing contract. It was not the Commission's intention that the *Draft Decision* proposed amendment would affect these contracts. The Commission also recognises that in accordance with section 2.50 of the Code nothing contained in an access arrangement limits the terms and conditions a service provider can agree with a user or prospective. Accordingly, the Commission no longer requires the *Draft Decision*'s proposed amendment A3.2.

On a separate but related issue, the Commission has some concerns regarding clauses 61 and 63 which rely upon the definition of 'Insolvency Event' contained in the transportation agreement. As long as the transportation agreement forms part of the terms and conditions of access section 6.15 of the Code will, in the event of a dispute, bind the Commission to the provisions contained in the document, notwithstanding the fact that the Commission had not reviewed the provisions. As set out in numerous decisions, the Commission's preferred approach is to delete references to the transportation agreement from the access arrangement and for all relevant provisions relating to access to be incorporated into the terms and conditions of access.[432]

The Commission's specific concerns regarding the reliance of clauses 61 and 63 upon the definition of 'Insolvency Event' contained in the transportation agreement were raised with EAPL. EAPL has since provided a definition of an 'insolvency event' which is applicable to both EAPL and users and covers: the appointment of an administrator; a court application to be wound up or declared bankrupt; the

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431 EAPL response to the Draft Decision, 14 March 2001, p.25

432 Such as ACCC, *Final Decision: Access Arrangement proposed by APT Petroleum Pipelines Limited for the Wallumbilla to Brisbane Pipeline System,* 16 January 2002, p. 29. ACCC, *Final Decision: Access Arrangement proposed by Carpentaria Gas Pipeline Joint Venture for the Ballera to Mount Isa Pipeline System*, 16 January 2002, p. 22.

appointment of a liquidator; a declaration of insolvency, and other substantially similar events that have the same effect under law.[433] To avoid any uncertainty on the part of users and prospective users (section 2.24(f)) and for completeness and ease of reference, the Commission requires that this definition be specified within the access arrangement.

Amendment FDA 20

In order for EAPL's access arrangement for the MSP to be approved, the access arrangement must define 'insolvency event' as referred to in clauses 61 and 63 of Attachment D.

3.2.5.2 Receipt and delivery points

Commission's Draft Decision

In evaluating the receipt and delivery point provisions contained within EAPL's original access arrangement, the Commission noted that there were aspects which may be of some concern, including:

- The interpretation of 'reasonable commercial and technical grounds' in clause 28.1(6). The Commission considered that this clause may give EAPL an undesirable degree of discretion in accepting or rejecting transfers and proposed that the provision be deleted (proposed amendment A3.3);
- The requirement that all other users at a receipt or delivery point must agree to sharing a facility (clause 28.1(5)). The Commission considered this clause may give an incumbent user, who is a potential competitor of the transferee, some commercial advantage by being forewarned of the proposed transfer. The Commission concluded that this clause was unreasonable and proposed that it be deleted (proposed amendment A3.4);
- The flexibility in the use of receipt and delivery points as set out in the Request for Transportation Services - Request Sheet. The Commission noted that EAPL had already agreed to amend this form to include the option of multiple receipt or delivery points (proposed amendment A3.5); and
- Charges applicable to the new transportation agreement to not be less than the original charges. After considering this issue the Commission decided not to propose any changes to the relevant provisions.

Submissions in response to the Draft Decision

Origin's response to the proposed amendment A3.4 stated that a consultative process for any new user of a facility is necessary because accommodating a new user involves the establishment of, or possible modification to, the shared facility appointee, an apportionment process and any necessary confidentiality agreements.[434]

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[433] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 10.

[434] Origin submission, 1 March 2001, p. 2.

As to the Commission’s proposed amendment A3.5, Origin agreed that the *Request for Transportation Services* form should be modified to include the option of multiple receipt and delivery points. Origin was, however, concerned that it was unclear whether the total pipeline MDQ was calculated as the sum of individual delivery point MDQs or over a number of delivery points in aggregate. Origin considered that the latter process should prevail to enable users to take advantage of any aggregation.[435]

EAPL’s response to the Draft Decision

Responding to the proposed amendment A3.3, EAPL asserted that the clause was reasonable and consistent with section 2.24(c) of the Code and accordingly rejected the Commission’s proposal.[436] This rejection was despite EAPL agreeing in its response to submissions in August 2000 that it would delete the clause.[437]

EAPL also disagreed with the Commission’s proposed amendment A3.4.[438] EAPL submitted that it is appropriate in cases where it does not own or operate facilities at a receipt or delivery point that arrangements be made with the owner or operator to ensure that EAPL has access to the facilities and that access be unaffected by another user of the receipt or delivery point. EAPL stated that this was the intent of the clause and it would not object to an amendment which better reflected the intent. Within the revised access arrangement clause 28.1(5) has been replaced by clause 77(e) which EAPL has submitted meets its need and provides for all situations where EAPL does not own a receipt point or delivery point.

While EAPL did not consider that the Commission’s proposed amendment A3.5 was necessary, EAPL agreed to amend the request form as proposed by the Commission.[439] The request form now provides for multiple receipt and delivery points (see Attachment F of the Access Arrangement).

Revised access arrangement

Clause 8 and 77 provide for the transfer of receipt or delivery points. Specifically, clause 77 states that EAPL may only withhold its consent to such a transfer on reasonable commercial or technical grounds and may make its consent subject to conditions if they are reasonable on commercial or technical grounds. These grounds include, amongst other things, that:

- where the facilities at the receipt point or delivery point are not owned by EAPL, the user arranging and agreeing with all or any other users of the relevant receipt point or delivery point for EAPL to have access to those facilities at no cost to EAPL (clause 77(e)); and
- the transfer not affect its ability to operate the pipeline properly (clause 77(f)).

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435 Origin submission, 1 March 2001, p. 2.

436 EAPL response to the Draft Decision, 14 March 2001, p. 26.

437 EAPL response to submissions, 17 August 2000, p. 29.

438 EAPL response to the Draft Decision, 14 March 2001, p. 26.

439 EAPL response to the Draft Decision, 14 March 2001, p. 27.

Commission's considerations

As set out in the *Draft Decision*, the Commission continues to have some reservations in relation to the operation of clause 77(f) (previously clause 28.1(6)). The Commission recognises that EAPL must be accorded the ability to withhold its consent if the transfer would be contrary to the operational and technical requirements necessary for the safe and reliable operation of the pipeline (pursuant to section 2.24(c) of the Code). However, the Commission is concerned that the terminology used may have the effect of providing EAPL with an undesirable degree of discretion to withhold its consent to a transfer. Thus, to ensure that the provision is consistent with section 2.24(c), the Commission considers that the provision should be amended to use the terminology contained in section 2.24(c).

Amendment FDA 21

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 77(f) of Attachment D to state that the transfer not affecting the operational and technical requirements necessary for the safe and reliable operation of the pipeline.

With respect to clause 77(e) (previously clause 28.1(5)), the Commission is satisfied that the revised clause clarifies EAPL's intention. While a user will need to obtain the consent of other users to ensure EAPL is provided access at no cost, the Commission considers this is reasonable. The Commission notes that in accordance with clause 7 of Attachment D an incumbent user would be unable to unreasonably withhold its consent given it is also required to ensure EAPL is provided access to receipt and delivery points which are owned or operated by another party. Therefore, the Commission does not require any amendment to this provision.

The Commission has assessed Origin's proposition that the total pipeline MDQ be calculated as the aggregate of delivery points rather than as the sum of individual delivery points MDQ. The issue of whether a user can aggregate their MDQ will have implications for both the application of imbalance charges, which are calculated across receipt and delivery points, and overrun charges, which are calculated at individual receipt and delivery points. It is not clear to the Commission from Origin's submission to which aspect it is referring. If Origin's concerns are with the imposition of imbalance charges, the Commission notes that these concerns may have been addressed with the revised balancing provisions submitted by EAPL in November 2002. These provisions refer to receipt and delivery points in the plural, indicating that an imbalance charge will only apply if a user withdraws in excess of the aggregate MDQ.

If, however, Origin's concerns are with the imposition of overrun charges at individual receipt and delivery points the Commission notes that these are still applicable at individual receipt and delivery points. The Commission has examined whether this is reasonable. It considers that the ability for users to allocate total pipeline MDQ over a number of delivery points in aggregate may affect other areas such as pipeline delivery pressures and the operation of compressors. In the absence of any financial consequence for users it is clear that EAPL would bear the cost of any such aggregation. The inequitable financial burden this would place on EAPL is, in the Commission's view, contrary to EAPL's legitimate business interests (section 2.24(a)).

Accordingly, the Commission considers the application of overrun charges to individual receipt and delivery points to be reasonable.

Finally the Commission notes that EAPL has amended the *Request for Transportation Services - Request Sheet* to provide for multiple receipt or delivery points.

3.2.5.3 Operational and balancing provisions

Commission's Draft Decision

The Commission's *Draft Decision* noted the need for greater certainty in relation to operational requirements and balancing provisions. In particular, the Commission noted the amount and discretionary nature of the balancing charges proposed and considered that the wording of the clause relating to the service fee may be confusing.[440] It also questioned whether a mark up on the cost of purchase of gas was necessary, given the added imposition of the service fee. The Commission acknowledged that EAPL's procedures were still under development and that EAPL had undertaken to establish a review process to consult with industry participants, users and the Commission prior to amending these procedures. Accordingly, the Commission proposed an amendment requiring EAPL to review the provisions and charges within six months (proposed amendment A3.6).

Submissions in response to the Draft Decision

The MEU's submission outlined the role of the Gas Market Company (GMC) in establishing, implementing and administering the Gas Retail Market Business Rules (Business Rules) which contained nomination procedures applicable to all gas networks in NSW. The MEU stated that while the operational provisions contained in EAPL's access arrangement were not inconsistent with the Business Rules it was concerned that any amendment to EAPL's provisions could give rise to inconsistency. [441] In relation to the need for consistency with the Business Rules the MEU stated:

> Any change to EAPL's operational and balancing provisions could affect competition and GRMCo's costs in the NSW gas retail market. To promote competition, it is important to ensure that the operational and balancing provisions for both the distribution systems and transmission systems are consistent.[442]

Given these concerns, the MEU suggested that the Commission's proposed amendment A3.6 be reworded to require EAPL to ensure that any changes made to the operational and balancing provisions be 'consistent with any government approved scheme put in place by the industry to give effect to retail contestability'. [443]

AGLWG also noted the development of nomination and balancing procedures by the NSW gas industry and suggested that network and transmission systems should complement each other. AGLWG proposed that only the principles of nominations and balancing process should be defined in the access arrangement and if required 'fall

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440 EAPL access arrangement, 5 May 1999, Attachment 2, clause 6.

441 MEU submission, 5 February 2001, pp. 1-2.

442 MEU submission, 5 February 2001, p. 2.

443 MEU submission, 5 February 2001, p. 2.

back' arrangements be included in the event that the procedures proposed by the industry are not implemented.[444]

As to the Commission's proposal that a review of the operational and balancing provisions be conducted within six months of approval of the access arrangement, AGLWG stated that it supported the amendment.

A further point raised by AGLWG was the suggested imbalance tolerance limits. AGLWG submitted that it would be concerned if the tolerance limits applied on an individual delivery point basis.[445]

EAPL's response to the Draft Decision

EAPL rejected the Commission's proposal that a review of the operational and balancing provisions be undertaken within six months of the access arrangement being approved. According to EAPL such an amendment was not necessary for the access arrangement to comply with the Code. EAPL argued that the proposed access arrangement contained sufficient detail in relation to the current arrangements for balancing, nominations and other operational matters for users to understand the terms of the reference service.[446] EAPL concluded:

> .. given the statutory obligation to comply with an access arrangement, and the potential sanctions for breach of that obligation, it is not appropriate that completion of the review within a certain period be mandated in the access arrangement.[447]

Revised access arrangement

Following some concerns regarding the risks surrounding imbalances EAPL submitted an amended Attachment E in September 2002. The principal concern raised by EAPL[448] was that if a significant pipeline imbalance were to arise it may result in the inability to maintain minimum delivery pressures under contract to all shippers. EAPL submitted that excessive imbalances may require it to operate compressors more often and less efficiently than would otherwise be the case. In light of these concerns, EAPL submitted that sufficient incentives for users to remain in balance should be incorporated within its revised access arrangement.

In submitting the revised Attachment E, EAPL noted that it was participating in a working group convened by MEU which was considering network and retailer reconciliation and balancing as part of the development of arrangements for FRC in the NSW gas market.[449] EAPL submitted that while it was anticipated that the outcome of this group would have an impact on contractual arrangements within 3-12 months this was not something that could be dealt with at present.

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[444] AGLWG submission, 28 February 2001, p. 3.

[445] AGLWG submission, 28 February 2001, p. 4.

[446] EAPL response to the Draft Decision, 14 March 2001, p. 27.

[447] EAPL response to the Draft Decision, 14 March 2001, p. 27.

[448] EAPL proposed amendment to the revised access arrangement, 14 September 2002, p. 2.

[449] EAPL response to the Commission, 14 September 2002.

Attachment E imposes responsibility upon users to control and, where necessary, adjust nominations, and vary receipts and deliveries of gas to ensure that each day the quantity of gas received into the pipeline equals the quantity delivered to the user's delivery points. Within this framework an imbalance is calculated as the difference between a user's inputs, withdrawals and changes in the quantity of its share of users' linepack (these terms are defined in Attachment E).

If an imbalance exists and is likely to jeopardise the ability of EAPL to comply with the requirements of any transportation agreement or to operate the pipeline properly, EAPL may require the user to correct the imbalance as soon as possible. If the user fails to correct, or take reasonable action to correct, the imbalance within four hours of the receipt of notice, EAPL may reduce the quantities of gas received, transported and delivered to or on behalf of the user. Alternatively, EAPL may purchase a quantity of gas to correct a negative imbalance.

In addition to these consequences, there are also provisions relating to a user's obligation to rectify imbalances. The first of these imposes an obligation upon users to rectify daily imbalances in accordance with their imbalance limit (where the imbalance limit for a user is defined according to their aggregate receipt point MDQ[450]). In cases where a user's imbalance exceeds its daily imbalance limit the user must adjust its receipts and deliveries to reduce the imbalance to within the limit by the end of the following day. If a user does not comply with this provision EAPL may apply a short term imbalance charge equal to 50 cents for each GJ in excess of the imbalance limit for that day and each day thereafter until the imbalance is reduced to within the imbalance limit. If a user's imbalance is in excess of its imbalance limit for four consecutive days then EAPL may purchase gas to correct the negative imbalance and charge the user 150 per cent of the actual purchase price.

The second series of provisions regarding obligations to rectify imbalances relates to correcting imbalances that occur in previous months. In accordance with these provisions where an imbalance is not corrected within the following month then EAPL may charge the user a long term imbalance charge.[451] Alternatively, where the imbalance is a shortfall, EAPL may correct the shortfall by purchasing gas at the receipt point and charging the user 150 per cent of the amount paid by EAPL. Procedures for trading monthly imbalance quantities are also contained within Attachment E.

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450 If a user's aggregate receipt point MDQ is:

- greater than or equal to 50 TJ, that user's imbalance limit will be equal to plus or minus 10 per cent of their aggregate receipt point MDQ; or
- less than 50 TJ that user's imbalance limit will be equal to plus or minus 5TJ.

451 This charge is calculated by multiplying the imbalance existing on the last day of the third month by the imbalance rate, defined in the Attachment A as 250 per cent of the capacity reference tariff.

Submissions in response to the revised access arrangement

In response to EAPL's revised balancing provisions, the EMRF expressed a clear objection to the application of the $0.50 - $1.50[452] per GJ imbalance charge arguing that no additional charge was warranted.[453]

Commission's considerations

The Commission notes that there have been a number of changes to the balancing requirements from the original access arrangement submitted by EAPL (in May 1999) to the revised access arrangement submitted in 2002. As a result of these significant amendments the Commission's concerns expressed in the *Draft Decision* regarding the service fee and the review process are no longer relevant. In assessing the reasonableness of the revised provisions, the Commission has been mindful of the objections raised by the EMRF and section 2.24(c) of the Code (which requires the Commission to take into account the operational and technical requirements necessary for the safe and reliable operation of the pipeline).

The Commission considers that in the main the revised balancing arrangements are reasonable in that they provide users with:

- a reasonable imbalance limit which is applied to the users receipt and delivery points in aggregate;
- sufficient opportunity to rectify imbalances before the relevant imbalance charges are applied;
- flexibility in rectifying monthly imbalances including the ability to trade imbalances; and
- the necessary incentive to remain in balance as required for the safe and reliable operation of the pipeline.

However, the Commission has some concerns in relation to the quantum of charges applicable when a user has a negative imbalance. Specifically, the Commission is concerned that where a user has a negative imbalance they will be required to pay both the relevant imbalance charge as well as being liable for a charge equal to 150 per cent of the purchase price paid by EAPL to rectify the imbalance. This would in effect mean that users with a negative imbalance would be penalised twice while a user who had a positive imbalance would only incur a single short term imbalance charge. The Commission does not consider that such an outcome would be equitable or reasonable and notes that other service providers, including NT Gas Pty Ltd[454] and APT Petroleum

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[452] It is unclear to the Commission which charge the Energy Markets Reform Forum is referring to when it states $1.50 per GJ. The Commission is aware that EAPL has proposed a short term balancing charge of $0.50 per GJ, a long term balancing charge of 250 per cent of the capacity reference tariff and a charge of 150 per cent in cases where it has to purchase gas for negative imbalances.

[453] Energy Markets Reform Forum, 28 January 2003, p. 1.

[454] NT Gas Pty Ltd, Access Arrangement for Amadeus Basin to Darwin Pipeline, February 2003, p. 35.

Pipelines[455], only require a user to pay the amount paid by the service provider or the prevailing price of gas at the receipt point.

Accordingly, the Commission considers that in the event that a user has a negative imbalance, EAPL should apply the relevant imbalance rate and charge users the actual purchase price of the gas. In reaching this view, the Commission notes that the imposition of imbalance charges will continue to encourage users to remain in balance and in turn facilitate the safe and reliable operation of the pipeline.

Amendment FDA 22

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the obligation to rectify provisions contained within the revised Attachment E and in particular clauses 2(b) and 6(b).
>
> For clause 2(b) EAPL must amend the provision to state that if the user's imbalance is in excess of the imbalance limit for four consecutive days, EAPL may purchase gas to correct a user's negative imbalance, and the user will be liable for a charge equal to the actual purchase price of the gas.
>
> For clause 6(b) EAPL must amend the provision to state that in the case of a negative imbalance, correct the imbalance by purchasing gas at the receipt point and charging the user the amount paid by EAPL for that gas (which will be treated as gas supplied by the user at the receipt point). EAPL will notify the user promptly after it corrects an imbalance in this manner.

Although the Commission considers the balancing provisions to be reasonable in the main, it notes the concerns raised by the MEU and AGLWG regarding the need to develop consistency between the operational and balancing provisions in place for distribution and transmission systems. The Commission is aware that APT is a member of the Industry Reconciliation Working Group (a group facilitated by the GMC) which is presently working toward the harmonisation of nominations arrangements between the transmission and distribution systems. Given that this group also consists of representatives from the gas retail market and wholesale gas shippers, the Commission is satisfied that this is the relevant forum for any change.

Nevertheless, the Commission is aware that if the group were to decide to introduce changes to the balancing arrangements for transmission systems EAPL may be required to amend the approved balancing arrangements. To ensure that such changes are able to be enacted without EAPL having to submit revisions in accordance with section 2.28 of the Code the Commission considers it prudent to include a provision in the access arrangement which enables such variation.

Amendment FDA 23

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must include a provision within Attachment E stating that EAPL may vary the balancing provisions contained in Attachment E without having to submit

[455] APT Petroleum, Access Arrangement for Roma-to Brisbane Gas Pipeline, September 2002, p. 11.

revisions to the access arrangement only if the variations are consistent with any government approved scheme put in place by the industry.

Finally, the Commission notes that Attachment C5 refers to imbalance charges as set out in Attachment E4. The Commission has not received Attachment E4 and considers that EAPL is in fact referring to Attachment E in which the balancing process is set out. To avoid any confusion on the part of users or prospective users (section 2.24(f)), the Commission suggests that EAPL amend Attachment C5 to refer to Attachment E.

Amendment FDA 24

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend Attachment C5 to state the user may be liable to pay imbalance charges as set out in Attachment E.

3.2.5.4 Gas quality

Commission's Draft Decision

The Commission's *Draft Decision* proposed that EAPL amend the access arrangement to ensure that any new specification recommended by the AGA's Gas Specification Working Group and approved by the relevant jurisdictions be reflected in the access arrangement (proposed amendment A3.7).

Submissions in response to the Draft Decision

The MEU has informed the Commission that the NSW Government was in the process of developing a regulation to implement the AGA's proposed specification for distribution networks. Accordingly, the MEU suggested that EAPL should be required to deliver gas to all custody transfer points in accordance with the AGA's proposed specification.[456]

EAPL's response to the Draft Decision

In response to the Commission's proposed amendment A3.7, EAPL submitted that it would not object to the adoption of the wider AGA approved specification once the legislation necessary to facilitate the change is in place in the relevant jurisdictions.[457]

Revised access arrangement

Attachment G states that gas must meet the specification as defined in AS34565 *Specification for General Purpose Natural Gas* once released or if the standard is not released the gas must meet the specification reasonably established by EAPL. Clause 20 of Attachment D further provides that EAPL may vary the specification if required by law to do so or a common gas specification is established for South Australia, Victoria, NSW and ACT by any organisation having jurisdiction over gas specification.

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[456] MEU submission, 5 February 2001, p. 2.

[457] EAPL response to the Draft Decision, 14 March 2001, p. 28.

Clauses 18 and 19 impose responsibility upon users and EAPL to ensure that gas at the receipt point and delivered to the delivery point meet the specification. Clause 22 further provides that if EAPL agrees to accept gas that is non-specification, it may require the user to restrict or terminate the quantity of gas received into the pipeline to ensure that gas delivered to all users meets the specification. Clause 23 requires EAPL and the user to notify each other as soon as they become aware of gas received at the receipt point failing to meet the specification. Clause 24 in effect states that the user will indemnify EAPL for any loss, cost, expense or damage which arises out of the receipt of non-specification gas by EAPL at a receipt point.

Submissions in response to the revised access arrangement

ExxonMobil expressed a number of concerns regarding clauses 19, 23 and 24. In relation to clause 19, ExxonMobil argued that if a user has delivered gas within specification at the receipt point, then that user should be entitled to receive gas within specification at the delivery point. ExxonMobil went on to argue that a user has no control over whether EAPL accepts non-specification gas and thus the liabilities for direct or indirect damages should be allocated between EAPL and the user according to whether the non-specification gas is authorised or unauthorised.[458]

In light of this distinction ExxonMobil argued that clause 24 should be clarified to apply to unauthorised non-specification gas so that a user should not be required to indemnify EAPL in instances where EAPL authorises the delivery of non-specification gas. ExxonMobil added that reciprocal clauses should be added to the access arrangement requiring EAPL to indemnify the user for any loss, cost, expense or damage arising out of the receipt by EAPL of authorised non-specification gas at a receipt point or the delivery of authorised non-specification gas at the delivery point.[459]

In addition to these proposals ExxonMobil suggested that clause 23 of Attachment D be amended to require EAPL to notify the user if non-specification gas has been, or is about to be, delivered to a delivery point.[460]

EAPL's response to submissions on the revised access arrangement

Responding to the concerns expressed by ExxonMobil, EAPL stated that in accordance with clause 19 it is responsible for delivering on-specification gas subject to all users delivering on-specification gas into the pipeline.[461] EAPL claimed that as it is not in a position to observe and physically control gas entering the pipeline at receipt points, it cannot reasonably be required to accept risk and liability for non-specification gas entering the pipeline. Accordingly EAPL argued that liabilities associated with the receipt of non-specification gas should be shared among the users.

In relation to clause 24, EAPL stated that it may be reasonable that it be unable to claim against a user if it authorises the receipt of non-specification gas from a user at a receipt point. However, EAPL submitted that it should not be obliged to indemnify a

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[458] ExxonMobil submission, 10 July 2002, p. 1.

[459] ExxonMobil submission, 10 July 2002, p. 2.

[460] ExxonMobil submission, 10 July 2002, p. 1.

[461] EAPL response to submissions, 25 September 2002, p. 2.

user against liability to others for damages as a result of the non-specification gas entering the pipeline. EAPL went on to reject ExxonMobil's suggestion that the user be indemnified in connection with receipt of authorised non-specification gas and for delivery of authorised non-specification gas at the delivery point. EAPL asserted that such a suggestion was not reasonable given that it does not have physical and legal control of the gas at the receipt point.

As to ExxonMobil's suggestion regarding clause 23, EAPL submitted that the provision is founded upon the assumption that awareness of entry of non-specification gas into the pipeline system will generally result from awareness of it entering at a receipt point.[462] EAPL submitted that gas analysis is not generally undertaken at delivery points and thus no reference was made to this possibility. However, EAPL agreed that an additional obligation could be incorporated requiring both EAPL and a user to notify the other when either becomes aware of non-specification gas leaving the pipeline at a delivery point.

Commission's considerations

In relation to EAPL's proposal to adopt Standards Australia's *Specifications for General Purpose Natural Gas*, the Commission notes that this standard was released in January 2003 as Australian Standard, AS 4564. Given EAPL's intention to adopt this standard, the Commission considers it relevant to amend Attachment G to recognise the publication of this standard.

Amendment FDA 25

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must remove the following statement from Attachment G 'If such specification is not published, then gas must meet the specification reasonably established by EAPL' and amend the Standards Australia number to state AS 4564.

On the issue of non-specification gas the Commission has considered ExxonMobil's contentions regarding clause 19 and the rights of a user delivering specification gas into the pipeline to receive specification gas. The Commission acknowledges EAPL's submission that it may not always be in a position to observe or control the quality of gas entering into the pipeline at receipt points. Rather it would appear that this aspect is within the control of the user. The Commission agrees that EAPL cannot be required to accept the risk and liability for non-specification gas entering the pipeline and accordingly requires no amendment to this provision.

In relation to ExxonMobil's suggestion that clause 23 be extended to delivery points, the Commission notes that it may not always be practical for EAPL to provide such notification. For example, it would not always be possible for EAPL to notify users of non-specification gas at the delivery point where the receipt point is not owned by EAPL. In addition, it is possible that by the time non-specification gas reaches the delivery point, co-mingling may result in the gas meeting the required specifications. On balance, the Commission does not consider that such an amendment is necessary.

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[462] EAPL response to submissions, 25 September 2002, p. 2.

Nevertheless, EAPL has agreed to the inclusion of a provision requiring both EAPL and the user to notify the other when either becomes aware of non-specification gas leaving the pipeline at a delivery point. Accordingly, EAPL must amend its access arrangement to provide for such an obligation. On a separate but related issue, the Commission considers that in the event that EAPL becomes aware of non-specification gas entering the pipeline (either as a result of a user informing it or through some other avenue) it should notify all of those users who may be affected. The Commission considers that this would ensure the interests of users are adequately taken into account (section 2.24(f)).

Amendment FDA 26

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 23 of Attachment D to state that EAPL and the user must each notify the other as soon as they become aware of gas received at the receipt point or leaving the delivery point failing to meet the specification.
>
> In the event that EAPL becomes aware of non-specification gas being received at the receipt point or leaving the delivery point it will notify any other user who may be affected.

On the issue of whether clause 24 should be amended to limit a user's requirement to indemnify EAPL to instances where the non-specification gas is unauthorised, the Commission notes EAPL's comments that such a limitation may be reasonable. The Commission considers that this limitation reflects a more balanced outcome for both users and EAPL and accordingly requires an amendment to clause 24.

Similarly, the Commission is of the view that reciprocal indemnity clauses should be included requiring EAPL to indemnify users in instances where it expressly authorises a user to deliver non-specification gas into the pipeline. Although EAPL does not have physical and legal control of the gas at the receipt point, the reciprocal clauses are intended to be based upon the provision of an express authorisation. The Commission considers that it would be unreasonable for EAPL to expressly permit a user to deliver non-specification gas into the pipeline while still exposing the user to any damages arising out of that authorisation. Such an exposure would clearly be contrary to the interests of users (section 2.24(f)).

Further, as a user has to bear both direct and consequential liability for damages arising from unauthorised use of non-specification gas it appears reasonable and not contrary to the legitimate business interests of EAPL to allow for a symmetry of liability so that if EAPL authorises the use of non-specification gas and a user in reliance on that authorisation enters non-specification gas into the pipeline resulting in damage EAPL should be subject to the same level of liability faced by the user. Thus to provide for a more reasonable and balanced outcome, the Commission requires an amendment to clause 24 to provide for reciprocal indemnities in cases where EAPL provides an express authorisation for the delivery of non-specification gas by a user into the pipeline.

Amendment FDA 27

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 24 of Attachment D to state that:

a. the user will indemnify EAPL for any loss, cost, expense or damage which arises out of or in connection with the receipt by EAPL from or on behalf of the user of any quantity of unauthorised non-specification gas at a receipt point (including direct, indirect and consequential loss); and

b. EAPL will indemnify the user for any loss, cost, expense or damage which arises out of or in connection with EAPL's express authorisation for the delivery of non-specification gas by a user into the pipeline (including direct, indirect and consequential loss).

3.2.5.5 Prudential requirements

Commission's Draft Decision

As set out previously, the Commission's *Draft Decision* expressed some concern in relation to the various prudential requirements contained within the original proposed access arrangement. The Commission was concerned that the differences in prudential requirements for different transactions may result in different requirements being applied to different users and/or transactions. The Commission considered that a more appropriate approach would be for the access arrangement to set out the prudential requirements applicable across all transactions (proposed amendment A3.8).

EAPL's response to the Draft Decision

EAPL's response to the *Draft Decision* stated that it did not object to the Commission's proposed amendment.[463]

Revised access arrangement

Provisions relating to the prudential requirements for a prospective user are set out in clauses 12.1, 12.8, 12.26 while those applying to a user are set out in clauses 1(a) and 81 of Attachment D.

Clause 12.1 states that in order for a prospective user to obtain access to a service they must meet the prudential requirements contained in clause 12.8. The requirements set out in clause 12.8 state that a prospective user:

- must be resident in, or have a permanent establishment in, Australia;
- must not be under external administration as defined in the Corporations Act 2001 or under any similar form of administration in any other jurisdiction; and
- may be required to provide reasonable security in the form of a parent company guarantee or a bank guarantee or similar security with the nature and extent of the security will being determined with regard to the nature and extent of the obligations of the prospective user under the transportation agreement.

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[463] EAPL response to the Draft Decision, 14 March 2001, p. 28.

Clause 12.26(c) requires a prospective user to reasonably demonstrate its financial ability to pay for the services and its commercial ability to satisfy the requirements of the transportation agreement before EAPL will be obliged to enter into a transportation agreement. Clause 12.26(d) in turn states that if requested by EAPL, a prospective user must provide a satisfactory performance guarantee or other satisfactory security to EAPL guaranteeing the performance of its obligations under its transportation agreement.

For existing users, clause 1(a) of Attachment D states that EAPL will be entitled to require a user to provide security for the performance of its obligations under a transportation agreement, with the security being of such type and such extent as EAPL reasonably determines. Clause 81 states that a user may be required to provide and maintain a financial security for the performance of its obligations under the transportation agreement, in the form of an appropriate guarantee or letter of credit, or parent company guarantee.

In addition to these provisions, clause 76(h) states that EAPL's consent to the transfer of capacity may not be unreasonably withheld subject to the intending user demonstrating its creditworthiness to EAPL's reasonable satisfaction. This includes providing EAPL with suitable security for the performance of its obligations under the transportation agreement.

Commission's considerations

The Commission acknowledges that EAPL has sought to clarify the prudential requirements for prospective users and users within clauses 12.8 and 81. However, while these amendments ameliorate those concerns expressed in the *Draft Decision*, the Commission has some further concerns regarding the range of prudential requirements that exist outside clauses 12.8 and 81. In particular, the Commission is concerned that there is the potential for inconsistency to arise between the prudential requirements for prospective users as set out in clauses 12.8, 12.26(c), 12.26(d) and 76(h) and the requirements for users as set out in clauses 81 and 1(a).

For instance in the case of prospective users, clause 12.26(c) refers to the prospective user demonstrating its ability to pay for the services and its commercial ability to satisfy the requirements of the transportation agreement. The clause does not, however, specify how a user would demonstrate its commercial ability to satisfy the requirements of the transportation agreement. This clause could be replaced by the requirement that the prospective user meet the prudential requirements set out in clause 12.8. This replacement would in effect render clauses 12.26(c) and 12.26(d) superfluous with 12.8(c) according EAPL the ability to require the prospective user to provide reasonable security. The Commission considers that this amendment would eliminate any inconsistency between clauses and in turn limit any confusion among prospective users as to the prudential requirements applicable (section 2.24(f)).

Amendment FDA 28

In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace clauses 12.26(c) and 12.26(d) with a provision stating that prior to EAPL being obliged to enter into a transportation agreement, the prospective user must have met the prudential requirements set out in clause 12.8 of the access arrangement.

While clause 76(h) uses the term 'intending user' the Commission cannot discern any real difference between a prospective user and an intending user, and accordingly has concluded that the term 'prospective user' is more appropriate as this is used in the Code and in EAPL's access arrangement generally.

As with clause 12.26(c), clause 76(h) does not specify what a prospective user would have to produce to demonstrate its creditworthiness or the form of security required. Again this clause could be replaced by the requirement that the prospective user meet the prudential requirements set out in clause 12.8. Such a requirement would avoid any uncertainty on the part of prospective users (section 2.24(f)) and avoid any potential inconsistency.

Amendment FDA 29

In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace clause 76(h) of Attachment D with a provision stating the prospective user meeting the prudential requirements set out in clause 12.8 of the access arrangement.

As to the provisions relating to the prudential requirements for users, the Commission was initially concerned that there may be some degree of uncertainty on the part of users as to the level of security they would be required to provide under either clauses 1(a) or 81 of Attachment D. This concern was brought to the attention of EAPL. In response EAPL stated that clause 81 was designed to interpret clause 1(a) further in terms of the form of security contemplated.[464] While this may be EAPL's intention, the Commission considers that this level of interrelationship is not clear. Consequently, to avoid any uncertainty on the part of users (section 2.24(f)) the Commission requires an amendment be made to clause 1(a) to reflect this relationship.

Amendment FDA 30

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 1(a) of Attachment D to state that EAPL will be entitled to require a user to provide security for the performance of its obligations under a transportation agreement as set out in clause 81 of the access arrangement.

[464] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 12.

3.2.5.6 Overrun charges

Commission's Draft Decision

The Commission's *Draft Decision* noted that while EAPL's proposed overrun charges appeared excessive, they would provide a deterrent to users who may otherwise use overruns as a form of interruptible service in the knowledge that interruption was unlikely to occur. The Commission concluded that if overruns were used in this manner EAPL would suffer a loss of revenue.[465]

Submissions in response to the Draft Decision

Responding to the *Draft Decision*, Origin accepted that a reasonable overrun regime was necessary to discourage users from under booking capacity and utilising overruns knowing that adequate capacity would be available if needed.[466] It considered that the overrun charge should be set a reasonable level, for example 1.35 times the capacity charge for the interruptible service. To deal with the problem of under booking capacity, Origin proposed a retrospective penalty for overruns in excess of 10 per year. In addition Origin proposed that the overrun charge should apply to the receipt point applicable to the user rather than the furthermost receipt point as proposed by EAPL.

Revised access arrangement

As detailed in clause 9 of Attachment D, an overrun will occur where EAPL receives (or delivers) at a receipt point (or a delivery point), a quantity of gas in any hour or on any day which exceeds the MHQ or the MDQ respectively. Clause 10 states that the overrun may be authorised if EAPL agrees to the overrun prior to the receipt or withdrawal of gas. If no such agreement is reached prior to the overrun occurring, or if the overrun exceeds the authorised quantity, the overrun will be deemed unauthorised.

A user must pay an overrun charge for delivery point overruns with charges differing depending on the size of the overrun (0-5 per cent of MDQ and greater than 5 per cent of MDQ) and whether the overrun is authorised or unauthorised. The various rates applicable for overruns are set out in Attachment C5 and are replicated below.

Table 3.2.5.1: EAPL's proposed overrun charges

Size of overrun	Authorised	Unauthorised
0-5% of MDQ	100% of capacity reference tariff	200% of capacity reference tariff
Greater than 5% of MDQ	200% of capacity reference tariff	350% of capacity reference tariff

The overall overrun charge is the product of the applicable rate for an authorised or unauthorised overrun rate, the overrun quantity and the distance from the furthermost receipt point on the pipeline to the delivery point at which the overrun occurred.

Clause 11 of Attachment D in effect imposes liability upon a user if EAPL is unable to comply with obligations to receive or deliver gas for other users, as a result of that user's unauthorised overrun.

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465 ACCC, *Draft Decision: MSP*, p. 153.

466 Origin submission, 1 March 2001, p .3.

Submissions in response to the revised access arrangement

TXU submitted that the proposed overrun charges were excessive and inappropriate when spare capacity exists.[467] TXU suggested more reasonable charges for:

- overruns between 0-5% of MDQ: 100 per cent of the capacity reference tariff for authorised overruns and 130 per cent for unauthorised overruns; and
- overruns greater than 5% of MDQ: 130 per cent of the capacity reference tariff for authorised overruns and 150 per cent for unauthorised overruns.

EAPL's response to submissions on the revised access arrangement

EAPL[468] defended its overrun policy stating that it provides users with flexibility in incurring a limited overrun quantity and limited number of occurrences before overrun charges apply. EAPL rejected TXU's claims that the proposed overrun charges are excessive, stating that the charges provide an appropriate economic signal to users to contract sufficient capacity to reflect their daily and annual contractual requirements. EAPL further argued that the use of overruns by users seeking to avoid contracting for capacity would result in EAPL failing to fully recover allowable revenue under the proposed tariff structure.

Commission's considerations

While some changes have been made to the proposed overrun charges from the original access arrangement, the charges still appear excessive for overruns over 5 per cent of MDQ and unauthorised overruns between 0-5 per cent of MDQ. For example, the charges applied to the CWP are 120 per cent for authorised overruns and 200 per cent for unauthorised overruns.[469] However, as noted in the *Draft Decision*, comparisons of this nature must be qualified in light of such factors as different tariff structures for services and any conditions that might be attached to authorisation of overruns (such as a limited number in any one period).

The Commission notes the arguments put forward by Origin that an overrun policy is necessary and that the overrun charge should be set at a reasonable level. However, as discussed in the *Draft Decision*, the Commission considers that the penalties may be warranted where spare capacity exists in order to prevent the misuse of overruns by users which would be contrary to EAPL's legitimate business interests (pursuant to section 2.24(a)). On this basis, the Commission considers the charges reasonable and will not require an amendment to the proposed overrun charges.

In relation to the distance used to calculate the overrun charge, the Commission agrees with Origin that the charge should be based on the receipt point applicable to the user rather than the furthermost receipt point as proposed by EAPL. The difference in distance between receipt points on the MSP can be substantial and the access arrangement as drafted could result in a significantly disproportionate penalty being incurred by the user which would be contrary to the interests of users and prospective

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467 TXU submission, 24 July 2002, p. 7.

468 EAPL response to submissions, 25 September 2002, p. 4.

469 ACCC, *Final Decision: CWP*, p. 106.

users (section 2.24(f)). The Commission does not consider it to be within the legitimate business interests of EAPL to charge disproportionate penalties to users. Accordingly, the Commission requires the following amendment.

Amendment FDA 31

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 4(b) of Attachment C5: Overrun Charges to state the distance calculated from the applicable receipt point to the delivery point at which the overrun occurred.

3.2.5.7 Amendments

Submissions in response to the Draft Decision

Origin had some concerns regarding provisions within the original access arrangement which accorded EAPL the ability to issue or modify procedures or documents.[470] Origin submitted that the access arrangement should require that any such actions by EAPL only be taken after drafts have been circulated to users for comment with any reasonable comments received taken into account in drafting final modifications.

Commission's considerations

The Commission notes that these provisions have not been repeated in the revised access arrangement and thus the assessment of reasonableness is no longer relevant.

3.2.5.8 Liabilities and indemnities

Submissions in response to the Draft Decision

Origin asserted that liability should be limited to direct losses for all parties, with one exception, that is:

> where the default actions of one user causes EAPL to default on its obligations to other users, the defaulting user's liability should extend to EAPL's liability for the direct losses of the other users. Direct losses of a party should exclude losses incurred by a party due to its own negligence or default and losses which a party would not have incurred had it acted in a reasonable and prudent manner and used reasonable endeavours to mitigate its losses.[471]

In addition, Origin noted that clauses within the access arrangement relating to liability already covered by clause 24 (now clause 73) such as clauses 5.4, 7.4, 7.5, 7.7 and 16.5 (now clauses 11, 21, 22, 24 and 53 respectively) should be deleted.

Revised access arrangement

The revised access arrangement included new provisions relating to liabilities and indemnities. Clause 72 of the revised access arrangement provides that EAPL and users will be required to indemnify the other for any loss arising out of its gross negligence or wilful misconduct. Clause 73 further provides that any liability of either party will be limited to direct loss only and does not extend to consequential loss,

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[470] Origin submission, 1 March 2001, p. 3.

[471] Origin submission, 1 March 2001, p. 3.

claims brought by third parties or loss of business or other income except where loss or damage arises from:

- the delivery of non-specification gas by the user into the pipeline;
- the failure by the user to deliver gas within the specified pressure range;
- an unauthorised overrun by the user;
- liability of EAPL arising due to a user's imbalance; or
- as otherwise set out in the transportation agreement.

Submissions in response to the revised access arrangement

ExxonMobil submitted that clause 73 should be clarified to ensure that the limitation of liability applies generally and not just to gross negligence or wilful misconduct.[472] ExxonMobil argued that the user's liability should be limited in the case of authorised non-specification gas and that exceptions to EAPL's limitation of liability should include authorised non-specification gas and authorised overruns.

EAPL's response to submissions on the revised access arrangement

In response to ExxonMobil's contentions regarding the limitation of liability, EAPL asserted that it is implicit that the limitation of liability in clause 73 applies generally.[473]

Commission's considerations

The Commission accepts that terms and conditions suitable in any particular contract will be dependent upon the particular circumstances of each contract and each party. In this regard it is noted that the parties are themselves free to negotiate terms and conditions which vary from the Code, as enshrined in section 2.50(c) of the Code.

Clause 72 operates as an indemnity provision indemnifying parties from claims made by third parties. Clause 73 operates as an exclusion provision excluding or limiting liability.

The Commission agrees with ExxonMobil that it is not entirely clear how EAPL intends clauses 72 and 73 to operate and whether the two clauses can be reconciled. For instance, clause 73 purports to limit the aspect of remoteness of damage between parties by providing that except for the circumstances contained in clauses 73(a) – (e) only direct losses are recoverable and will not cover 'any consequential loss, claims brought by third parties or loss of business or other income'. This raises the issue of a potential conflict with clause 72, which requires an indemnity for 'any loss' and envisages a scenario in which the indemnified party is indemnified for claims of third parties where such claims are for gross negligence or wilful misconduct.

In order to reconcile the potential inconsistencies between clauses 72 and 73, the Commission considers it appropriate to amend clause 73 to include acts of gross negligence and wilful misconduct.

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472 ExxonMobil submission, 10 July 2002, p. 2

473 EAPL response to submissions, 25 September 2002, p. 3.

Further, the Commission notes that the exceptions set out in (a) to (d) list circumstances in which a user is at fault and may be construed as terms of strict liability. The Commission has considered whether strict liability is appropriate and also whether other exceptions should be included. The Commission does accept that as the user has the physical and legal control of the gas at the receipt point, that there should be a sufficient deterrent to ensure that incidents do not occur/ Strict liability provides such a deterrent. However, the Commission considers that there are circumstances in which EAPL should also be strictly liable for loss, including where it has not maintained the safety and integrity of the pipeline. The Commission therefore considers it appropriate and reasonable that additional provisions be included in clause 73 to take into account these two aspects.

A further issue that has been considered by the Commission is Origin's proposals to:

- Extend the liability for direct loss to direct losses suffered by other users where the loss has been caused by the default actions of a user; and
- Limit loss of a party to loss not caused or exacerbated by the party itself. That is, reduce the compensation for loss where a party was contributory negligent or failed to mitigate loss.

With regard to the first proposition, the Commission does not consider that this provision would be appropriate. In forming this view the Commission notes that there is sufficient protection for users' rights in the laws of contract and negligence. Where the default of one user prevents EAPL from meeting its obligations under the transportation agreement, any users that have as a result suffered loss may be able to take legal action against EAPL for breach of contract.

The Commission, however, considers that there is some value to Origin's second proposition in that it meets the legitimate business interests of service providers (section 2.24(a)), the interests of users and prospective users (section 2.24(f)) and the economically efficient operation of the covered pipeline (section 2.2(d)). The Commission also considers it reasonable that parties bear the risk of their own actions and not be able to seek compensation for loss which could have been avoided. Accordingly, the Commission proposes an additional provision to clause 73 setting out this limitation upon losses in instances where the behaviour of a party contributed to the damages or where a party failed to mitigate their loss.

In addition to these amendments, the Commission requires amendments to clauses 73(a) and 73(e). The amendment to clause 73(a) is consistent with the Commission's amendment to clause 24(a) limiting the exception to unauthorised non-specification gas. The reasons underlying this proposal are set out in the discussion regarding gas quality.

In relation to clause 73(e), the Commission recognises that provisions of this type provide EAPL with substantial flexibility. However, while the access arrangement is intended to be a statement of minimum requirements, the Commission is concerned that EAPL may be able to amend the transportation agreement unilaterally. Such an ability would clearly be contrary to the interests of users and prospective users (section 2.24(f)). To avoid such an outcome while also providing EAPL and users with the necessary degree of flexibility, the Commission considers that the clause should be amended to require the agreement of both the user and EAPL.

Finally, in relation to Origin's proposal that clauses relating to liability should be consolidated within one provision, the Commission considers that it is appropriate that the consequences of certain actions be brought to the attention of the user within the context of related terms and conditions. The Commission therefore proposes no amendment to this aspect. The culmination of the aforementioned proposed amendments are set out below.

Amendment FDA 32

In order for EAPL's access arrangement for the MSP to be approved EAPL must amend clause 73 of Attachment D to state:

Unless agreed by the parties and set out in the transportation agreement, any liability of either party will be limited to direct losses only, and does not extend to any consequential loss, loss bought by third parties or loss of business or other income, except where such damage or loss arises out of:

a. gross negligence or wilful misconduct by either EAPL or the user;

b. the delivery of unauthorised non-specification gas into the pipeline;

c. the failure by the user to deliver gas within a specified pressure range;

d. an unauthorised overrun by the user;

e. liability of EAPL arising due to the user's imbalances; or

f. failure by EAPL to maintain the safety and integrity of the pipeline.

73A However, neither party will be liable for loss which could have been mitigated against or for loss suffered as a result of contributory negligence on the part of the other party.

3.2.5.9 Daily variance charges

Revised access arrangement

Attachment C5 of EAPL's revised access arrangement states that EAPL may require a user to pay a daily variance charge for daily variances of more than 10 per cent which occur on more than four days in a month or twenty-four days in a contract year. The daily variance charge is calculated by multiplying the daily variance rate (equal to 120 per cent of the capacity reference tariff) by the daily variance quantity. This charge was not contained in the original access arrangement proposed by EAPL. [474]

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[474] Where the daily variance quantity is equal to the greater of:

- the sum for all delivery points, of the absolute differences between the user's nomination and the actual quantity of gas delivered to a user; and
- the sum for all receipt points, of the absolute differences between the user's nomination and the actual quantity of gas received from the user.

Submissions in response to the revised access arrangement

TXU has stated it regards the charge as excessive. TXU was of the view that a more appropriate imbalance charge would be around 30 per cent of the capacity reference tariff payable by the user on the day on which the variance occurred.[475]

EAPL's response to submissions on the revised access arrangement

EAPL[476] has stated that it believed TXU's references to imbalance charges were actually references to daily variance charges.[477]

In further correspondence with the Commission, EAPL has clarified its intentions with regard to the daily variance charge.[478] Specifically, EAPL stated that the charge is designed to bring a discipline to the operation of the pipeline which depends on appropriate user nomination behaviour. EAPL submitted that inappropriate nomination behaviour can have an effect on the efficient operation of the pipeline. EAPL added that the charge is only intended to bring discipline to user behaviour and not to raise revenue and will generally be applied where utilisation levels dictate. EAPL submitted that this intention will be reinforced by competitive pressure from the EGP.

Also, EAPL noted that the removal of the Balancing Incentive Scheme (a scheme which had operated to provide an incentive for correct nominations) applicable to AGLGN's network had made the charge more relevant as a means of providing an incentive for users to correctly nominate their daily requirements. On the issue of the actual charges, EAPL stated that the capacity charge component of the referent tariff is based on the MDQ whereas the daily variance charge is based on the daily variance which is the difference between the amount nominated at a receipt point (or delivery point) and what is actually received (or delivered).

Commission's considerations

The Commission understands that daily variance charges are a mechanism by which service providers seek to encourage users to correctly nominate their gas needs and in so doing ensure the efficient operation of the pipeline. The Commission further understands that users can avoid daily variance charges by ensuring that the quantity of gas they nominate to receive at each receipt point (or have delivered at each delivery point) is within a range of plus or minus 10 per cent of their MDQ. The Commission considers this range provides users with some latitude and notes that the charge would only be applied if the variance occurs on more than four days in the month or 24 days in the contract year.

The Commission therefore considers that a penalty of 120 per cent for variations beyond the 10 per cent range is reasonable in that it: provides users with the requisite incentive to correctly nominate their gas usage and further provide for the

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475 TXU submission, 24 July 2002, p. 8.

476 EAPL response to submission, 25 September 2002, p. 4.

477 Like EAPL the Commission has also interpreted TXU's submission as a reference to the daily variance charge.

478 EAPL response to the Commission, 14 July 2003.

economically efficient operation of the MSP (section 2.24(d)); ensures the legitimate business interests of EAPL (section 2.24(a)) are taken into account; and adequately accounts for the interests of users and prospective users (section 2.24(f)).

3.2.5.10 Order of priority of service

Revised access arrangement

Clauses relating to the order of priority of service are contained throughout the revised access arrangement. Of particular relevance are:

- clause 5.5 which states that EAPL will act in a non-discriminatory manner in providing services;
- clause 6.10 specifying that Firm Services will have higher priority than Negotiable Services and existing contracts for non-firm services;
- clauses 10.1, 54 and 55 of Attachment D which provide that if any interruption or reduction of services occurs, EAPL will provide Firm Services then Negotiable Services; and
- clause 10.4 which states that priority is subject to any established pre-existing contractual rights to a higher priority (if any).

Submissions in response to the revised access arrangement

In reference to the order of priority proposed by EAPL, Origin raised some concerns, particularly in relation to clause 10A, regarding the reference made to pre-existing contractual rights to a higher priority. Origin asserted that EAPL should delete this provision unless it could advise whether such pre-existing rights existed and their position in the priority schedule.[479]

TXU also expressed some concerns in relation to the order of priority.[480] First in the case of Firm Services, TXU stated that while it supports EAPL's proposal to accord existing agreements for firm transportation the equivalent priority to Firm Service, it is concerned that some of those existing users will obtain preferential treatment and prices for access to the pipeline.

Second, in the case of Negotiable Services, TXU stated that while it accepted that these services could not undermine pre-existing contractual rights it believed that in accordance with the intent of the Code, EAPL should not be able to restrict the prioritisation. In addition TXU submitted that any potential user should be able to negotiate terms equal to existing services.

EAPL's response to submissions on the revised access arrangement

Responding to TXU's concerns regarding the prioritisation of existing contracts, EAPL[481] argued that there is no requirement in the Code that prospective users be offered access on terms commensurate with existing contracts. Notwithstanding this,

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479 Origin submission, 1 March 2001, p. 2.

480 TXU submission, 24 July 2002, p. 1.

481 EAPL response to submissions, 25 September 2002, p. 3.

EAPL submitted that existing transportation agreements for firm transportation are, with respect to terms and conditions, substantially the same as those contained in the revised access arrangement.

In regard to the priority of Negotiable Services, EAPL argued that TXU had misunderstood the terms of clause 9.2 which states that:

> Negotiable Services will have a priority agreed on a case by case basis but will not be higher than Firm Service.[482]

In effect this provision provides that a Negotiated Service may have the same priority as a Firm Service, but not higher. EAPL also noted that clause 5.5 of the revised access arrangement states that it will act in a non-discriminatory manner in providing services.

According to EAPL the term ‘non-discriminatory manner’ within the context of clause 5.5 means that EAPL will act in a manner which is consistent for each service offered and between each service offered, subject to differences which arise from legitimate economic, commercial and technical considerations.[483] These considerations include:

- the level of service sought and the appropriate tariff relative to that level; and
- the application of prudent discounts where permitted by the Code.

EAPL considers that treating users differently in situations where they seek different services or where prudent discounts are necessary to maximise throughput economically should not be viewed as discriminatory.

Commission's considerations

The Commission has examined the concerns raised by Origin and TXU regarding the potential for existing users to obtain preferential treatment and prices for access to the pipeline. However, the Commission considers that in view of section 2.24(b) of the Code (which requires the Commission to take into account the firm and binding contractual obligations of the service provider or other persons already using the pipeline) clause 10.4 is reasonable. Moreover, the Commission notes EAPL's statement that existing agreements for firm services contain substantially the same terms and conditions as those contained in the revised access arrangement. Consequently, the Commission requires no amendment to this clause.

In relation to the priority of Firm Service users and Negotiable Service users, the Commission has assessed clauses 6.10, 10.1 and 54 with reference to EAPL's comments regarding clause 9.2 (which sets out that a Negotiable Service may have the same priority as the Firm Service but not higher than the Firm Service). However, this provision is inconsistent with clauses 6.10, 10.1 and 54 which state that the Firm Service will have a higher priority than the Negotiable Service in cases of interruption or reduction in services.

Given this contradiction it is relevant to consider what a lower priority will mean to a user of a Negotiable Service. The Negotiable Service is designed to provide

[482] EAPL response to submission, 25 September 2002, p. 4.

[483] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 11.

prospective users with an alternative where their requirements and circumstances cannot be satisfied through a reference service.[484] In this case these differences will genuinely justify differences in terms and conditions including tariffs. However, these differences may not necessarily justify a lower priority than the reference service. The relative priorities of the services would have to be determined on a case by case basis given the specific economic, commercial and technical differences between the Negotiable Service and the Firm Service. Establishing priorities on this basis will, in the Commission's view, address both the legitimate business interests of EAPL (pursuant to section 2.24(a) of the Code) and those of users and prospective users (section 2.24(f)) adequately.

EAPL's comments in relation to clause 9.2 and its intention for the operation of clause 5.5, would appear to provide for priority to be determined in the manner described above. However, as stated above this is in contrast to clauses 6.10, 10.1 and 54. Given this contradiction and in view of the conclusions reached above, the Commission considers that clauses 6.10, 10.1 and 54 should be amended to ensure they operate consistently with clauses 9.2 and 5.5. That is, the order of priority should be determined in a non-discriminatory manner on the proviso that the Negotiable Service and non-firm services under pre-existing contracts do not have a higher priority than the Firm Service. The Commission also requires that EAPL's intentions in relation to the term non-discriminatory manner be expressly stated in the definitions section of its access arrangement.

Amendment FDA 33

In order for EAPL's access arrangement for the MSP to be approved, EAPL must:

- Amend clause 6.10 to remove references to the order of priority of services;
- Amend clause 9.2 to state that Negotiable Services will have a priority agreed to in a non-discriminatory manner on a case by case basis with the priority agreed to not being higher than the Firm Service;
- Amend clause 10.1 to state that if any interruption or reduction of services occurs, the order of priority will be determined in a non-discriminatory manner with the Negotiable Service not having a higher priority than the Firm Service;
- Amend clause 54 of Attachment D to state that subject to any pre-existing contractual right to a higher priority, if there is any interruption or reduction of services or inability to meet transport obligations or force majeure affecting the services, then to the extent practicable, EAPL will provide services in a non-discriminatory manner with the Negotiable Service, including non-firm services under pre-existing contracts, not having a higher priority than the Firm Service; and
- Include the following definition within Attachment A, 'Non-Discriminatory Manner' means that EAPL will act in a manner which is consistent for each service offered and between each service offered, subject to differences

[484] EAPL revised access arrangement, 30 April 2002, clause 9.1.

which arise from legitimate economic, commercial and technical considerations.

3.2.5.11 Custody, control and title

Revised access arrangement

Clause 26 states that custody and control of gas provided by the user will pass from the user to EAPL at the receipt point with that custody and control transferred back to the user at the delivery point. Clause 27 further provides that title to the gas remains with the user at all times.

Submissions in response to the revised access arrangement

ExxonMobil has submitted that clause 26 was unclear as to whether EAPL would be liable for any loss or damage that occurred while the gas was within its custody and control. ExxonMobil contended that in light of EAPL's responsibility for the management and operation of the pipeline it should bear the risk and be liable for any loss or damage that occurs whilst it has custody and control of gas.[485]

EAPL's response to submissions on the revised access arrangement

In response to ExxonMobil's contentions, EAPL stated it was obliged to deliver the quantities of gas it received and hence the risk for gas was implicitly held by it. EAPL concluded as the service provider it is responsible for gas lost due to its negligence.[486]

Commission's consideration

The Commission has examined the purpose of clauses 26 and 27 and considered how these clauses fit within contract and tort law.

Clauses 26 and 27 provide that the title to gas will remain with the user at all times, even though the physical custody and control of the gas remains with EAPL. As such, these clauses confirm the property rights of users and clarify the users' rights in the event that the property is lost or damaged in some way.

The transportation contract governs the relationship between the parties, and it is this contract which stipulates the rights and obligations of both parties. Compensation is available for a party who has suffered loss as a result of a breach of the contract by another party to the contract. Compensation may also be sought by users and EAPL in instances where the damage or loss is caused by a negligent act or omission, either by a party to the contract or by a third party.

EAPL's revised access arrangement itself contains a number of examples of clauses relating to the duties and obligations of both parties to ensure that gas is received, transported and delivered according to the agreement between the parties. For example clauses 49-52 relate to EAPL's obligations to ensure that interruptions or reduction of services are minimised.

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[485] ExxonMobil submission, 10 July 2002, p. 2.

[486] EAPL response to submissions, 25 September 2002, p. 2.

The Commission has also examined the amendment suggested by ExxonMobil, with reference to the remedies available in contract and tort law and in view of clauses 72 and 73 (which outline liability and indemnity rights of both parties) and other relevant provisions which set out the duties of both EAPL and users. The Commission considers that the proposed amendment would have the effect of rendering EAPL liable for any damage caused to the gas while in the pipeline, whether or not the damage was caused by EAPL, and as such may impose an undue burden upon EAPL and be contrary to EAPL's legitimate business interests (as referred to by section 2.24(a) of the Code).

Given this potential imposition, the Commission considers that the amendment proposed by ExxonMobil should not be adopted. The Commission considers that there is sufficient clarity of the rights and obligations of both EAPL and users in contract and tort law to afford users protection in the event of damage or loss. Moreover, the Commission considers that clauses 26 and 27 serve a useful purpose and are reasonable in their current form.

3.2.5.12 Force majeure and capacity charge relief

Revised access arrangement

Pursuant to clause 56 EAPL will be relieved of its obligations if a force majeure[487] event arises. If this occurs, clause 57 requires EAPL to: as soon as reasonably practicable give written notice to the user of the event and when the event terminates; and endeavour to remedy the force majeure as soon as reasonably practicable and give notice to the user upon the termination of the force majeure event. If the force majeure event extends beyond twelve months, either party will be entitled to terminate the transportation agreement subject to the event not being resolved by negotiation (clause 58).

If a force majeure event results in an interruption or curtailment of services, the user will be relieved from the liability to pay the capacity charge but will be liable to pay any other charge (clause 59). This capacity charge relief will be determined on a pro-rata basis in reference to the reduction in the user's MDQ and will be for the period commencing on the expiration of the 24 hours from the occurrence of the force majeure event and terminating at a time when EAPL, in its reasonable opinion, is able to provide services.

Submissions in response to the revised access arrangement

TXU stated that it regards the force majeure definition proposed was too broad and unreasonably passed onto users a number of risks within the control of the service provider. Consequently, TXU proposed that a number of amendments be made to the definition to limit the risk allocation to that expected within the industry.[488] Briefly, TXU proposed that the following areas of the definition be amended (revisions marked):

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[487] The definition of force majeure is contained in Attachment A to the access arrangement.

[488] TXU submission, 24 July 2002, p. 9.

c. strikes, lockouts or other industrial disturbances, other than a strike, lockout or other industrial disturbance involving a party to this Transportation Agreement;

f. inability to obtain or curtailment of supplies of electric power, water, fuel or other utilities or services or any other material or equipment necessary for the continued provision of the services, other than where the inability to obtain or curtailment of supplies occurs due to the action or lack of action by EAPL;

h. inability to obtain or revocation or amendment of any permit, license, certificate of authorisation of any government or regulatory body, other than where the inability to obtain or revocation or amendment occurs due to the action or lack of action by EAPL.[489]

ExxonMobil has argued that capacity charge relief should occur from the point in time that EAPL cannot offer the user's full MDQ, which should be the commencement of the force majeure period rather than 24 hours from the occurrence of the force majeure.[490]

In addition, Origin submitted that capacity charge relief should not be limited to events where force majeure is claimed and should be available for prolonged outages.[491]

EAPL's response to submissions on the revised access arrangement

Responding to TXU's proposal to amend the definition of force majeure, EAPL submitted that the definition currently in place reflected industry contracting practice.[492] EAPL considered that it would be unreasonable to exclude strikes. As to the other two amendments proposed by TXU, EAPL contended that they were unnecessary given that the definition already states 'any cause not reasonably within the control of the party claiming force majeure'.

Referring to ExxonMobil's submission EAPL asserted that the timing of the commencement of the force majeure event (clause 60) was reasonable. It also stated that this does not reflect the fact that in many circumstances a time delay will arise between when a force majeure event occurs and when delivery of gas is affected.[493]

Commission's considerations

The Commission has examined the concerns raised by TXU. It does not consider that the provision in its current form is unreasonable. The Commission notes that the force majeure provision, standard in many commercial contracts, is designed to exclude a party from liability for failure to perform an obligation under a contract, where that failure was due to forces, either in nature or as a result of human activity, beyond that party's control. This objective is clearly encapsulated within EAPL's force majeure definition, which states that:

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489 TXU submission, 24 July 2002, p. 9.

490 ExxonMobil submission, 10 July 2002, p. 2.

491 Origin submission, 1 March 2001, p. 4.

492 EAPL response to submissions, 25 September 2002, p. 6.

493 EAPL response to submissions, 25 September 2002, p. 2.

> Force majeure means any cause not reasonably within the control of the party claiming Force Majeure which results in or causes a failure by such party in the performance of any one or more of its obligations under the Transportation Agreement notwithstanding the exercise by such party of due diligence.….

Relevantly, this definition includes the phrase 'notwithstanding the exercise by such party of due diligence'. This effectively removes the need for the inclusion of the statement 'due to the action or lack of action by EAPL' as proposed by TXU for clauses c and h. If EAPL acted or failed to act in a way which would be considered to be 'diligent' then it would be unable to claim force majeure. Consequently, the Commission does not consider these specific amendments proposed by TXU are necessary.

As to TXU's proposal to amend the clause relating to strikes, the Commission is concerned that the amendment would be too strict in that it would prevent either EAPL or users declaring a force majeure event where they had acted in a diligent manner to prevent or resolve the strike. The inability to declare a force majeure event in such an instance would be contrary to both the legitimate business interests of EAPL (section 2.24(a)) and the interests of users (section 2.24(f)). As a result the Commission is of the view that the provision in its current form is reasonable and does not consider that the amendment as proposed by TXU is warranted.

The Commission has also examined the arguments of both ExxonMobil and EAPL in relation to capacity charge relief. While EAPL contends that the impact of the force majeure event will not be immediate, the Commission considers that the 24 hour limitation is arbitrary and exposes users to the potential to pay for services which they may not necessarily receive. Such an exposure would be contrary to the interests of users (section 2.24(f)). Consequently, the Commission considers that on balance it is unreasonable for EAPL to limit relief to 24 hours following the occurrence of the force majeure event. Rather, the Commission considers that the relief should be accorded as soon as the force majeure results in a reduction in the user's MDQ. The following amendment reflects this view.

In addition, the Commission is concerned that the decision to terminate capacity charge relief may also be arbitrary given that it turns upon when 'EAPL, in its reasonable opinion, is able to provide services'. The Commission considers that in the interests of users (section 2.24(f)), capacity charge relief should terminate when a user's MDQ is no longer affected by the force majeure event. Accordingly, the Commission requires an amendment to clause 60.

A further issue raised by the provision of capacity charge relief is whether throughput charge relief should also be provided. While a throughput charge is payable on the basis of the actual quantity of gas delivered, clause 59 of the revised access arrangement states that the user will not be relieved from liability to pay any other charge. The Commission considers it reasonable that users should be accorded throughput charge relief in the event of force majeure (section 2.24(f)) and does not regard this relief as being contrary to EAPL's legitimate business interests (section 2.24(a)). Accordingly, the Commission requires EAPL to amend clauses 59 and 60 to provide for throughput charge relief.

Amendment FDA 34

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 59 of Attachment D to state that in the event of interruption or curtailment of services as a result of a force majeure claimed by EAPL, the user will be relieved from liability to pay the capacity and throughput charge, but will not be relieved from liability to pay any other charge.

EAPL must also amend clause 60 of Attachment D to state that the capacity charge and throughput charge relief will be pro-rated to the reduction in the user's MDQ at the time the user's MDQ is reduced following the occurrence of the force majeure and terminating at a time when the user's MDQ is no longer affected by the force majeure.

The issue of whether capacity charge relief should be extended to prolonged outages, has also been considered by the Commission. The Commission is of the view that unless the event causing the prolonged outage could be limited to a force majeure or an event within the control of EAPL, then the extension of the provision could place an unreasonable financial burden and liability upon EAPL and may be contrary to EAPL's legitimate business interests (section 2.24(a)). Even if the provision could be limited to prolonged outages in the control of EAPL, users would still be exposed to prolonged outages caused by the negligence of other parties. Given these issues, the Commission considers that on these occasions remedies should be sought by users in either contract law (where the prolonged outage is caused by the failure of EAPL to perform an obligation under the contract), or in tort law (where the prolonged outage is caused by the negligence of another user). Accordingly, the Commission does not require an amendment to this provision.

3.2.5.13 Assignment

Revised access arrangement

Clause 65 entitles EAPL to assign its rights or obligations without the prior written consent of the user to any person who holds an interest in the pipeline or to a related body corporate. In any other circumstances EAPL must obtain prior consent from the user.

Submissions in response to the revised access arrangement

ExxonMobil stated that clause 65 does not contain a test to ensure the appropriate technical and operational competency of the assignee and thus could impose a significant risk on users of the pipeline.[494]

EAPL's response to submissions on the revised access arrangement

EAPL rejected ExxonMobil's suggestion that a test to ensure the appropriate technical and operational competence of an assignee be incorporated into the access

[494] ExxonMobil submission, 10 July 2002, p. 2.

arrangement.[495] However, it stated that it would not object to a statement that the assignee be capable of performing the obligations under the transportation agreement.

Commission's considerations

The Commission notes the concerns raised by ExxonMobil in relation to assignment of the transportation agreement. However, it is not convinced that the risks identified by ExxonMobil would necessarily flow from such an assignment. That is, the Commission recognises that there are sufficient commercial imperatives for a pipeline owner to ensure that the pipeline is operated by a technically competent operator. Further, the Commission believes that to place limits on EAPL's right to assign its rights or obligations is unreasonable. The Commission notes EAPL's willingness to include a statement in the access arrangement that an assignee be capable of performing the obligations under the transportation agreement. The Commission considers this proposed amendment by EAPL to be reasonable and as meeting the concerns raised by ExxonMobil. An amendment to this effect is set out below.

Amendment FDA 35

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 65 of Attachment D to state that EAPL will be entitled to assign its rights or obligations under the transportation agreement, without the prior consent of the user, to any person who holds an interest in the pipeline or to a related body corporate within the meaning of the *Corporations Act 2001* on the proviso that the assignee is capable of performing the obligations under the transportation agreement. In any other circumstance EAPL will not be entitled to assign its obligations under the transportation agreement without the prior consent of the user (with such consent not to be unreasonably withheld).

3.2.5.14 Insurance

Revised access arrangement

Clause 74 states that each party will be obliged to effect and maintain certain levels of insurance for the term of the agreement. In addition, users will be required to carry all risk property damage insurance to a specified reasonable amount.

Submissions in response to the revised access arrangement

ExxonMobil submitted that clause 74 was too restrictive in that no allowance was provided for self insurance.[496]

EAPL's response to submissions on the revised access arrangement

Rejecting ExxonMobil's contentions, EAPL argued that clause 74 reflects the appropriate reciprocal obligations of EAPL and a user to carry all risk property damage

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495 EAPL response to submissions, 25 September 2002, p. 2.

496 ExxonMobil submission, 10 July 2002, p. 2.

insurance.[497] In its view self insurance is unacceptable and an uncertain means of protecting the interests of each of the parties.

Commission's considerations

The Commission has considered the issue of self-insurance. As the damages which may flow from events described in clause 74 cannot necessarily be isolated to the individual, the Commission is not convinced that self insurance provides other parties with an appropriate means of recovering damages. This is particularly the case where losses are substantial. Thus, to ensure that the interests of users and EAPL are adequately taken into account (sections 2.24(f) and 2.24(a)) and to maintain certainty and confidence in the arrangements, the Commission considers that external insurance is desirable and should be obtained by all parties. Consequently, the Commission considers that clause 74 is reasonable and does not require any amendment to be made.

3.2.5.15 System use gas

Revised access arrangement

Clause 39 requires users to supply gas for use as system use gas at their own cost.

Submissions in response to the revised access arrangement

Origin's submission stated that it strongly opposed the proposal for users to supply their own system use gas.[498] Origin submitted that it is the responsibility of the pipeline owner to manage the pipeline and thus it should be responsible for the costs incurred. Origin added that if the pipeline owner acquired the fuel gas at no cost then it would have no incentive to use the gas efficiently.

Similarly, TXU stated that in principle a service provider should be accountable for such costs to ensure that it has the necessary incentive to minimise usage and costs.[499] TXU also requested that the Commission confirm that EAPL's forecast operating expenditure excludes the cost of system use gas.

EAPL's response to submissions on the revised access arrangement

In response to the suggestion that the costs associated with system use gas may still be included within forecast operating expenditure, EAPL submitted that the costs had been removed.[500] EAPL also stated that it is common practice for system use gas to be provided by users.

Commission's considerations

The Commission has considered TXU's and Origin's contentions regarding the incentive for EAPL to use system use gas efficiently where it is not accorded the necessary cost incentives. The Commission is of the view that the economic incentives for EAPL to minimise consumption of system use gas will be the same whether or not

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[497] EAPL response to submissions, 25 September 2002, p. 3.

[498] Origin submission, 1 March 2001, p. 2.

[499] TXU submission, 24 July 2002, p. 8.

[500] EAPL response to submissions, 25 September 2002, p. 5.

EAPL pays for the gas. That is users will either be required to pay for system use gas directly or indirectly through the operations and maintenance costs.

The Commission has also examined the proposed provision and the definition of 'system use gas' to determine whether or not EAPL will be accorded any other incentives to consume reasonable quantities of system use gas. The 'system use gas' definition contained in Attachment A states that:

> system use gas means the quantities of gas necessary for the efficient operation of the pipeline, including gas used as fuel for compressors or other equipment, and quantities otherwise lost and unaccounted for in connection with the operation of the pipeline including as a result of any limitations on the accuracy of metering equipment but excludes linepack and gas lost from the pipeline due to the negligence or wilful default of EAPL.

Relevantly, this definition includes the phrases, 'quantities of gas necessary for the efficient operation of the pipeline' and 'excludes ….. gas lost from the pipeline due to the negligence or wilful default of EAPL'. The Commission considers that this definition will encourage efficient use of system use gas.

In light of the foregoing, the Commission considers that clause 39 is consistent with EAPL's legitimate business interests (section 2.24(a)) and is not contrary to the interests of users or prospective users (section 2.24(f)). Accordingly, clause 39 is reasonable and the Commission does not require any amendment.

3.2.5.16 Gas pressures and temperatures

Revised access arrangement

Provisions relating to gas pressure and temperature are contained in clauses 33 – 38. Of particular relevance are:

- clause 33 which requires the pressure of gas made available by the user at a receipt point to be within the limits reasonably specified by EAPL from time to time;
- clause 34 this clause requires users to indemnify EAPL for any loss, cost, expense or damage arising from its failure to deliver gas to the receipt point within the specified range;
- clause 35 which requires users to provide pressure relief devices; and
- clause 38 which requires users to use all reasonable endeavours to make the gas available at the receipt point at a daily average temperature of not more than 10 degrees Celsius above the mean ambient temperature.

Commission's considerations

The Commission is aware that the temperature and pressure requirements proposed by EAPL appear more restrictive than those in operation on other pipelines and may impose some costs upon users. However, this cost cannot be viewed in isolation, rather consideration must be given to the reasons underlying the inclusion of the provisions. The Commission understands that EAPL incorporated these operational and technical provisions following the pipe rupture downstream of the Moomba plant in 1982 and are designed to limit the potential for stress corrosion cracking of the pipeline.[501] Given that these operational and technical provisions have been incorporated to ensure that the integrity of the pipeline is maintained and are necessary for the safe and reliable operation of the pipeline (section 2.24(c)) the Commission considers clauses 33, 35, 36, 37 and 38 are not unreasonable.

3.2.5.17 Charges in respect of receipt or delivery points

Revised access arrangement

Attachment C5 states that EAPL is entitled to recover from a user or group of users:

- the cost of constructing capital improvements for receipt stations and delivery stations for the pipeline (which will remain the property of EAPL) specifically required to deliver gas to or receive gas from that user or group of users, including the construction of receipt stations and delivery stations; and
- the cost of operating and maintaining those capital improvements.

Commission's considerations

The Commission had some initial concerns with the potential operation of these clauses. Specifically, that a prospective user, who is unable to gain access to an existing receipt station or delivery point, would have no other option but to pay the costs quoted by EAPL. Moreover, in the absence of any competitive restraint it is possible that EAPL could attempt to extract monopoly rents from prospective users by charging excessive prices for the initial construction and ongoing operating and maintenance services. Such an outcome would not be in the interests of prospective users particularly given that the constructed receipt and delivery stations remain the property of EAPL.

While the Commission still has some concerns with this issue, it notes that in accordance with section 8.23 of the Code, a user may agree to pay the service provider a capital contribution. In addition section 8.24 provides that all obligations between the service provider and the user with respect to the capital contribution shall be as agreed between the service provider and the user.

In light of these provisions, the Commission examined what other measures may operate to limit any monopolistic behaviour by EAPL or to protect the interests of users and prospective users. In particular, the Commission has examined the dispute resolution provisions contained in section 6 of the Code. If a prospective user and service provider do disagree on the cost of construction the prospective user may be able to lodge an arbitration dispute under section 6.1 of the Code. The Commission considers that the presence of the arbitration mechanism should operate as a constraint upon the potential exercise of monopoly power by EAPL with regard to capital contributions for prospective users. Accordingly, the Commission does not require any amendments to these provisions.

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[501] EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 11.

3.3 Capacity management policy

3.3.1 Code requirements

Section 3.7 of the Code requires an access arrangement to include a statement that the covered pipeline is either a contract carriage pipeline or a market carriage pipeline.

3.3.2 Original access arrangement

Clause 14.1 of the original access arrangement states that the MSP is a contract carriage pipeline.

3.3.3 Commission's Draft Decision

The Commission concluded that clause 14.1 of the access arrangement satisfied the requirements of section 3.7 of the Code.[502]

3.3.4 Revised access arrangement

Consistent with the original access arrangement, clause 11.1 of the revised access arrangement contains a statement that the MSP is a contract carriage pipeline.

3.3.5 Commission's considerations

As the revised access arrangement includes a statement that the MSP is a contract carriage pipeline, the Commission considers that clause 11.1 satisfies the requirements of section 3.7 of the Code.

3.4 Trading policy

3.4.1 Code requirements

Section 3.9 of the Code requires the incorporation of a trading policy into an access arrangement where the pipeline is a contract carriage pipeline. A trading policy explains the rights of a user to trade its right to obtain a service to another person and pursuant to section 3.10 of the Code must, amongst other things, allow a user to transfer capacity:

- without the service provider's consent, if the obligations and terms under the contract between the user and the service provider remain unaltered by the transfer (a 'bare transfer'); and
- with the service provider's consent, in any other case. The consent of a service provider may be withheld only on reasonable commercial or technical grounds and the trading policy must specify conditions under which consent will be granted and any conditions attaching to that consent.

[502] ACCC, *Draft Decision: MSP*, p. 157.

Section 3.11 of the Code provides examples of transfers, other than bare transfers, that would be considered reasonable under section 3.10 of the Code. For example, it would be reasonable for the service provider to request that it should receive at least the same amount of revenue from the user should the user decide to change its delivery or receipt point.

3.4.2 Original access arrangement

EAPL's original access arrangement provided that users can trade rights in three circumstances:[503]

- a user may make a 'bare transfer' without the consent of EAPL if, prior to utilising it, the transferee notifies EAPL of the portion and nature of contracted capacity subject to the bare transfer;
- a transfer or assignment of all or part of a user's contracted capacity may occur by way other than a bare transfer with the prior written consent of EAPL. EAPL may withhold its consent only on reasonable commercial or technical grounds and may make such consent subject to reasonable commercial and technical conditions including conditions which are consistent with the principles for terms and conditions of service; and
- a user may request in writing a transfer of all or part of the MDQ for a receipt or delivery point to another receipt or delivery point. EAPL may withhold its consent to a transfer or may make its consent subject to reasonable commercial or technical conditions, including conditions which are consistent with the principles for terms and conditions of service. Section 15.3(2) stated that the transfer of delivery points for Class STP services was not allowed.

Details of the criteria which EAPL would seek to satisfy before granting its consent for any transfer of capacity other than a bare transfer were set out in clause 27.2(1)-(12) of Attachment 3 in the original access arrangement. These were as follows:

1. Users seeking to transfer MDQ must pay a reasonable charge determined and levied by EAPL, whether or not the transfer proceeds to completion;

2. EAPL and the intending user must execute a service agreement in relation to the transferred portion;

3. The MDQ specified is either from the same receipt point to the same delivery point specified in the service agreement;

4. The intending user must negotiate with any user for the sharing of the use of facilities with any conditions and charges, at no additional cost to EAPL;

5. The user and intending user must agree to pay a surcharge to EAPL for the service under the services agreement;

503 EAPL access arrangement, 5 May 1999, clause 15, p. 24.

6. In EAPL's opinion the intending user must demonstrate that it has made all the necessary arrangements with producers, purchasers and other users in respect to purchasing, receiving and selling gas;

7. The intended user accepts all obligations under an enhanced facilities agreement if the transfer of the MDQ is proposed before any enhanced facilities are completed;

8. If the transfer requires additional facilities at the receipt point or delivery point, the user or intending user must agree to pay EAPL for the cost of construction on such terms and conditions as reasonably determined and levied by EAPL;

9. The user must not be in default of the services agreement;

10. The intending user must provide a parent company guarantee where required by EAPL;

11. The intending user must pay or give to EAPL a letter of credit or bank guarantee where required by and of an amount reasonably determined by EAPL; and

12. EAPL must be satisfied that the intending user is solvent and has sufficient experience within the industry.

3.4.3 Commission's Draft Decision

In its *Draft Decision*, the Commission noted that while the trading policy proposed by EAPL closely followed sections 3.9 to 3.11 of the Code, a number of concerns were raised with regard to several proposed clauses.

Incitec was concerned with clause 27.2(1) which related to proposed charges for the transfer of capacity.[504] The Commission considered that the transfer of capacity may involve some costs, and that it may be in the legitimate interests of EAPL to levy a reasonable charge. Incitec also raised concern with clause 27.2(5) which would provide EAPL with broad discretion to levy a surcharge on transferred capacity. The Commission noted that under the Code any surcharge would need to be approved by the Commission prior to being levied.

In relation to the operation of clause 27.2(6), Incitec and the Commission expressed some concerns as to the discretion given to EAPL by this clause and the ability of EAPL to obtain commercially sensitive information from intending users. These concerns led the Commission to propose that EAPL's trading policy provisions be amended (proposed amendment A3.9), to the effect that an intending user would only need to provide EAPL with written confirmation that appropriate arrangements have been made, and that EAPL should not be able to obtain commercially sensitive information from intending users beyond the scope of this criterion.

Incitec also argued that clause 27.2(12) of the proposed access arrangement, which required a user to be a responsible and solvent person with an appropriate level of industry experience, should be deleted. EAPL responded that this clause relates to the

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504 Incitec submission prepared by NERA, 15 July 1999, pp. 16-17.

financial solvency of an intending user, and that to mitigate Incitec's concerns it may be appropriate to combine clauses 27.2(9) and (12). The Commission considered that this change was desirable and proposed amendment A3.10.

Incitec also raised concern with regard to clause 27.2(3), which placed restrictions on the use of receipt and delivery points for transferred MDQ. This and other issues relating to the transfer of receipt or delivery points were assessed by the Commission under terms and conditions (section 3.2 of the *Draft Decision*).

3.4.4 Submissions in response to the Draft Decision

AGLWG submitted that it agreed with the Commission's amendment (A3.9) which limits the ability of EAPL to obtain commercially sensitive information. However, AGLWG considered that it was critical that all users on the pipeline have appropriate arrangements in place for the supply and transport of gas upstream and downstream, as the absence of this may result in inaccurate allocation of gas to users potentially resulting in undue costs to those users.[505]

EAPL commented on the Commission's concern with clause 27.2(6) of Attachment 3 of the access arrangement. EAPL submitted that the ring fencing obligations under section 4 of the Code would prevent EAPL from improper use or disclosure of this information, and that it was the intention of EAPL that users would have complied by written confirmation as proposed in the *Draft Decision*. EAPL accordingly stated that it did not object to the proposed amendment.[506]

Amendment A3.10 proposed in the *Draft Decision* required EAPL to combine clauses 27.2(9) and 27.2(12) into a single requirement that the user must be able to demonstrate its creditworthiness to EAPL's reasonable satisfaction. EAPL stated that it did not object to this proposed amendment.[507]

3.4.5 Revised access arrangement

EAPL's trading policy is set out in clause 13 of its revised access arrangement. As with clause 15 of the initial access arrangement, the trading policy provides that: a user may make a bare transfer if the transferee notifies EAPL beforehand (clause 13.1), a user may transfer its contracted capacity other than by way of a bare transfer with the prior written consent of EAPL which is consistent with Attachment D (clause 13.2); and the user may transfer MDQ from a receipt or delivery point subject to consent from EAPL; and also subject to Attachment D of the revised access arrangement (clause 13.3).

Clause 76 of Attachment D sets out the criteria for assessing the reasonableness of a transfer which is not a bare transfer. The majority of the criteria are the same as those set out in the initial access arrangement, apart from the following:

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505 AGLWG submission, 28 February 2001, p. 3.

506 EAPL response to the Draft Decision, 14 March 2001, p. 28.

507 EAPL response to the Draft Decision, 14 March 2001, p. 27.

- 76(a) requiring a user seeking to transfer MDQ to pay a reasonable charge determined by EAPL whether or not the transfer proceeds to completion, including legal and other fees associated with consideration of the request to transfer;
- 76(e) which requires the intending user to provide written confirmation that it has made all the necessary arrangements with producers, purchasers and other users in respect to purchasing, gas sale, operating and multi-party receipt point and delivery point arrangements; and
- 76(h) specifying that the intending user demonstrates its creditworthiness to EAPL's reasonable satisfaction, including providing EAPL with suitable security for the performance of its obligations under the transportation agreement.

Clause 27.2(5) of the original access arrangement relating to the imposition of a surcharge has been removed from the revised access arrangement.

3.4.6 Submissions in response to the revised access arrangement

There were no submissions received in response to the revised access arrangement from interested parties.

3.4.7 Commission's considerations

As noted above, the Commission raised a number of concerns with the trading policy proposed by EAPL in the initial access arrangement, and proposed two amendments in response to these concerns. EAPL has incorporated the Commission's proposed amendments in its revised access arrangement, and made a number of other adjustments in response to issues raised by Incitec. Specifically:

- EAPL clarified clause 76(a) (formerly clause 27.2(1)) relating to transfer charges, specifying that these may include legal and other fees associated with the request for a transfer. This amendment addresses some of Incitec's initial concerns with the scope of the provision.
- EAPL amended the original clause 27.2(6) (now clause 76(e)) relating to the provision of information relating to upstream and downstream arrangements. As requested in amendment A3.9, this clause now requires the intending user to provide written confirmation that it has made all the necessary arrangements with producers, purchasers and other parties. However, the revised clause does not fully address the Commission's concerns regarding the ability of EAPL to request and obtain confidential information. Nevertheless, the Commission notes that clause 70 of the revised access arrangement will prevent EAPL from disclosing confidential information to other parties without prior approval of the user. Consequently, the Commission considers that together these provisions (clauses 76(e) and 70) will operate as a safeguard for users and prospective users. In addition they address the Commission's concerns on information provision.
- In response to amendment A3.10 of the *Draft Decision*, clauses 27.2(9) and (12) have been removed and replaced by clause 76(h). This states that the intending user must demonstrate its creditworthiness to EAPL's reasonable satisfaction.

The Commission considers that the amendments to the trading policy made by EAPL in the revised access arrangement address the concerns raised in the *Draft Decision* by both the Commission and interested parties.

The only remaining issue the Commission has with these provisions is the use of the term 'intending user'. This has not been defined in Attachment A and the Commission cannot discern any real difference between a prospective user and an intending user. To avoid any uncertainty, the Commission considers that EAPL should amend these clauses and use the term transferee. The Commission notes that this term is used in the Code to describe parties to whom capacity will be transferred.

Amendment FDA 36

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 77 of Attachment D by replacing the term 'intending user' with the term 'transferee'.

3.5 Queuing policy

3.5.1 Code requirements

Sections 3.12 to 3.15 set out the Code's requirements for a queuing policy. An access arrangement must include a queuing policy for determining the priority given to users and prospective users for obtaining access to a covered pipeline and for seeking dispute resolution (under section 6 of the Code).

Section 3.13 of the Code states that a queuing policy must be set out in sufficient detail to enable users and prospective users to understand in advance how the policy will operate. It must also, to the extent reasonably possible, accommodate the legitimate business interests of the service provider and of users and prospective users and generate economically efficient outcomes.

Section 3.14 of the Code allows the relevant regulator to require the queuing policy to deal with any other matter the regulator thinks appropriate taking into account the matters set out in section 2.24.

3.5.2 Original access arrangement

EAPL's original queuing policy proposed to offer services to all registered applications for FT, STP and negotiable services in order of registration of the request for service subject to any preserved contractual rights.

In accordance with the proposed policy, once an offer was made by EAPL a prospective user had 14 days in which to respond. If the response was positive then EAPL would provide a service agreement to the prospective user. The prospective user would then have 30 days to either sign the service agreement or notify EAPL that it wished to enter into negotiations.

Before being obliged to provide any services, the proposed policy required the prospective user to, among other things:[508]

- reasonably demonstrate that it had made the appropriate arrangements for upstream and downstream transport and supply of gas;
- reasonably demonstrate its financial ability to pay for the services; and
- subject to the financial standing of the prospective user, if requested by EAPL, provide a satisfactory performance guarantee or other satisfactory security to EAPL guaranteeing the performance of its obligations under the service agreement.

If a service agreement was not finalised the request for service would lapse. The available capacity then be offered to the next prospective user on the queue. The request would not, however, lapse in the event of a dispute. If a dispute were to arise then the request would retain its priority in the queue until the dispute was resolved in accordance with the Code.

3.5.3 Commission's Draft Decision

The Commission's *Draft Decision* concluded that the queuing policy proposed by EAPL largely satisfied the requirements of the Code. The Commission did, however, express concerns about the operation of clause 7.5(13)(b), which required a prospective user to demonstrate that it had made appropriate arrangements for upstream and downstream transport and supply of gas. Specifically, the Commission was concerned that if this provision were enforced it would provide EAPL with an unnecessarily high level of access to commercially sensitive information. Accordingly, the Commission proposed that the clause be amended to state that EAPL requires written confirmation, to its satisfaction, from users that the appropriate arrangements have been made (proposed amendment A3.11).

3.5.4 Submissions in response to the Draft Decision

While AGLWG supported the Commission's proposed amendment A3.11, it submitted that it is critical that all users on the pipeline have appropriate arrangements in place for the upstream and downstream supply and transportation of gas.[509] According to AGLWG if appropriate arrangements are not in place then an inaccurate allocation of gas to users may arise which could in turn result in undue costs or financial penalties to those users.

Origin noted that the order of priority on the queue would be subject to any pre-existing contractual rights entitling a user to higher priority.[510] Origin contended that EAPL should delete clauses relating to pre-existing contractual rights unless it could advise whether such rights exist and where they fit into the priority schedule.

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508 EAPL access arrangement, 5 May 1999, clause 7.5(13).

509 AGLWG submission, 28 February 2001, p. 4.

510 Origin submission, 1 March 2001, p. 2.

Although EAPL raised no objection to the Commission's proposed amendment A3.11, it submitted that the ring fencing obligations contained in section 4 of the Code would prevent EAPL from disclosing or improperly using such information.[511]

3.5.5 Revised access arrangement

EAPL has sought to align its revised queuing policy with those policies operating on other pipelines owned by APT, including the CWP and the Ballera to Mount Isa Pipeline.

Details of the queuing policy are set out in section 12 of the revised access arrangement. Broadly the policy proposes that where there is insufficient capacity to satisfy a user's request to obtain a service a queue will be formed. This queue includes all relevant requests that cannot be satisfied. The priority within the queue will be determined by the date a request is received by EAPL subject to clause 12.3.[512] Furthermore, a request for service at the reference tariff will have priority over a request for a service at less than the reference tariff.

At the time a request is placed in a new or existing queue, EAPL will advise the prospective user of:

- its position in the queue;
- the aggregate capacity of requests which are ahead of it on the queue;
- EAPL's estimate of when capacity may become available; and
- the size of any surcharge that may apply to developable capacity.

EAPL will update these details when the relative position of a request or the timing of available developed capacity changes.

Once in a queue, a prospective user may reduce, but not increase, the capacity sought in its request. An assignment of a request on the queue can be made to a bona fide purchaser of the prospective user's business or assets. Once every three months EAPL may request confirmation from a prospective user that it wishes to continue with its request. A request for service may lapse and be removed from the queue if:

- the prospective user does not respond to EAPL's request for confirmation within the specified 14 days;
- the prospective user notifies EAPL that it does not want to proceed with the request; or
- the entity to which the prospective user assigns its request does not meet EAPL's prudential requirements or fails to provide a guarantee as required by EAPL.

A request will not lapse in the event that there is a dispute. The request will retain its priority until the dispute is resolved in accordance with section 6 of the Code.

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511 EAPL response to the Draft Decision, 14 March 2001, p. 29.

512 This clause considers the relevant lodgement date in the event that an incomplete request is lodged.

When capacity becomes available that capacity will be progressively offered to each prospective user in the queue in order of priority (notwithstanding that such capacity is not sufficient to meet the needs of that prospective user). EAPL will advise each of those prospective users of its plans to make capacity available, and the terms and conditions on which the capacity will be available. A prospective user will have 30 days after an offer is made to enter into a transportation agreement, failing which the request will lapse or lose priority to those entering into such a transportation agreement (clause 12.22).

Prior to EAPL being obliged to enter into a transportation agreement, the prospective user must according to clause 12.26:

- provide written confirmation that it has made the appropriate arrangements for upstream and downstream supply and transport of gas;
- reasonably demonstrate its financial ability to pay for the services and commercial ability to satisfy the requirements of the transportation agreement; and
- if requested by EAPL, provide a satisfactory performance guarantee or other security to guarantee the performance of its obligations under the transportation agreement.

3.5.6 Submissions in response to the revised access arrangement

TXU stated that it:

> believes that EAPL's queuing policy is simplistic and that it is unlikely to result in the most efficient outcome or meet the section 8 Code requirements.[513]

TXU suggested that a more appropriate policy may be the policy proposed by Epic for the MAPS which involves an 'open season' on spare capacity when it becomes available.[514]

In addition, TXU submitted that EAPL needs to develop a policy for dealing with non-firm transportation capacity requests.

EAPL's response to submissions on the revised access arrangement

In response to TXU, EAPL stated that the policy is substantially the same as those approved by the Commission, in accordance with section 8 of the Code, for operation on the CWP, Roma to Brisbane and Carpentaria pipelines.[515] According to EAPL this queuing policy has not hindered the expansion of the latter two pipelines. Furthermore, EAPL submitted that the policy proposed by TXU may not be appropriate in the case of the MSP where a significant level of spare capacity exists.

In relation to TXU's suggestion that EAPL develop a queuing policy for non-firm requests, EAPL stated that it would evaluate whether spare interruptible capacity exists for the level of interruption that is acceptable for the prospective user. In such

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[513] TXU submission, 31 July 2002, p. 5.

[514] Epic Energy South Australia Pty Ltd revised access arrangement for the MAPS, 22 January 2002.

[515] EAPL response to submissions, 25 September 2002, p. 3.

circumstances where spare interruptible capacity at a level of potential interruption acceptable to the user exists, a queue would not need to be formed.[516]

3.5.7 Commission's considerations

EAPL's proposed queuing policy provisions are broadly consistent with those recently approved by the Commission in its consideration of the Wallumbilla to Brisbane access arrangement. Notwithstanding this, the Commission has examined the revised queuing policy giving consideration to:

- the purpose of a queuing policy, which is to allocate spare capacity where there is insufficient capacity to satisfy the needs of all users and potential users who have requested capacity;
- the substantial excess capacity with which the MSP is expected to operate with over the term of the initial access arrangement; and
- the issues raised by interested parties as to the appropriateness of the overall policy and specific provisions within the proposed policy.

Appropriateness of the proposed queuing policy

The Commission has considered the concerns raised by TXU that a queuing policy based on a 'first in first served' approach may be inappropriate for the MSP. As noted in its Final Decision for the MAPS, the Commission considers that in an environment of excess demand a 'first in first served' queuing policy would be problematic and give rise to an inefficient allocation of existing spare capacity. This is because:

> Under first in first served, where there is excess demand, users have an incentive to make ambit claims. Some market participants argued that this would result in unnecessary expansion, or at least obfuscate market signals regarding the need for new capacity. The Commission considers that these are valid concerns.[517]

However, where a pipeline is operating substantially below capacity such problems are unlikely to emerge as prospective users' requirements will be able to be met by existing available capacity.

As previously discussed the MSP currently has a substantial amount of excess capacity and based on the throughput forecasts provided by EAPL it appears that pipeline volumes are unlikely to approach capacity over the course of the access arrangement. On the basis of current utilisation and forecast throughput it would appear that there is sufficient capacity to meet prospective users' demand diminishing the incentive to make ambit claims.

The Commission therefore considers that EAPL's proposed 'first in first served' policy is appropriate for the MSP given the excess capacity expected to prevail over the initial access arrangement period. In addition, the Commission considers that EAPL's proposed policy is consistent with section 3.13 of the Code in that it:

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516 EAPL response to submissions, 25 September 2002, p. 3.

517 ACCC *Final Decision: MAPS*, pp. 176-194.

- is set out in sufficient detail to enable users and prospective users to understand in advance how the policy will operate;
- will generate economically efficient outcomes to the extent reasonably possible; and
- accommodates both the legitimate interests of EAPL and prospective users.

Moreover, the Commission notes that the policy is consistent with sections 2.24(a), 2.24(d) and 2.24(f) of the Code. Consequently, the Commission does not consider that the 'open season' queuing policy, as suggested by TXU, is currently warranted on the MSP. However, the Commission notes that if the pipeline approaches capacity in subsequent access arrangement periods, the suitability of the policy may need to be reconsidered.

Provisions within the proposed queuing policy

In its *Draft Decision*, the Commission noted that it had some concerns in relation to the requirement that prospective users reasonably demonstrate that they had made appropriate arrangements for upstream and downstream transport and supply of gas. The Commission was concerned that if such a requirement were enforced EAPL would have an unnecessarily high level of access to commercially sensitive information. Accordingly, the Commission proposed that the provision be amended to state that written confirmation to EAPL's satisfaction is required from the prospective user that appropriate arrangements have been made. In addition the Commission stated that EAPL should not be able to obtain commercially sensitive information beyond the scope of this criterion.

While EAPL has not objected to the Commission's proposed amendment and replaced 'reasonably demonstrate' with 'written confirmation' in clause 12.26(b), the revised clause does not fully address the Commission's concerns regarding the ability to obtain commercially sensitive information. Nevertheless, the Commission notes that clause 70 of the revised access arrangement and ring fencing provisions within the Code will prevent EAPL from disclosing confidential information to other parties without the prior approval of the user. The Commission considers that together these provisions will operate as a safeguard for users and prospective users and address the Commission's concerns. Consequently the Commission will not require any amendment to clause 12.26(b).

In relation to TXU's concerns regarding EAPL's policy for dealing with non-firm transportation capacity requests, the Commission notes that the policy makes no clear distinction between firm and negotiable services. The relevant provision within the revised access arrangement is clause 12.23 which states that:

> A request for a Service at the reference tariff will have priority over a request for a Service at less than the reference tariff

The term Service in this clause is defined by EAPL as encompassing both Firm Services and Negotiable Services. Accordingly, the provision provides that Firm and Negotiable services have equal priority, subject to a prospective user seeking the Firm or Negotiable service at the reference tariff having priority over a prospective user seeking either service at a discount.

The Commission agrees that if a prospective user is seeking the reference service at a discount to the reference tariff, then its position on the queue should be lower than the position of a prospective user prepared to pay the reference tariff for the reference service. This is consistent with the intent of the Code and the legitimate interests of the service provider. However, it is a concern that a prospective user seeking to obtain a service other than the reference service, which genuinely justifies a lower tariff, could lose their place on the queue to a prospective user seeking the reference service. This may occur when the tariff paid for the negotiated service is less than the reference tariff payable for the reference service. In effect, the Firm Service and Negotiable Service do not have equal priority. This is not in the interests of prospective users seeking an alternative service to the Firm Service.

This issue was raised in its consideration of the Wallumbilla to Brisbane pipeline access arrangement. In its Final Decision the Commission stated that the provision should be amended to state that the reference service and negotiated service have equal priority, subject to a prospective user seeking the reference service at the reference tariff having priority over a prospective user seeking the reference service at a tariff less than the reference tariff.[518] APT subsequently altered the clause to state that:

> A request for a reference service will have priority over a request for the same service at a tariff less than the reference tariff. Otherwise, the priority of a request for any service depends on the priority date.[519]

The Commission considers that a similar amendment could be made in this access arrangement which would take into account both the service provider's legitimate business interests (section 2.24(a)) and the interest of prospective users (section 2.24(g)).

Amendment FDA 37

In order for EAPL's access arrangement for the MSP to be approved, clause 12.23 must be amended to provide that the reference service and negotiated service have equal priority, subject to a prospective user seeking the reference service at the reference tariff having priority over a prospective user seeking the reference service at a tariff less than the reference tariff.

It was previously noted that Origin expressed concern regarding the higher priority within the queue accorded to parties with pre-existing contractual rights within the original proposal. This provision (clause 7.2(3)(d)) has not been included in the revised access arrangement. Section 10 of EAPL's revised access arrangement does set out the order of priority of services and states that these levels of priority are subject to established pre-existing contractual rights. However, these provisions refer only to the order of priority where an interruption or reduction of service occurs and not for the queuing policy. Thus the Commission is satisfied that the source of Origin's concerns has been amended by EAPL in its revised access arrangement.

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518 ACCC, *Final Approval: Access Arrangement proposed by APT Petroleum Pipelines Ltd for the Wallumbilla to Brisbane Pipeline System*, 11 September 2002, p. 5.

519 APT revised access arrangement Roma to Brisbane Pipeline System, September 2002, clause 6.4.

3.6 Extensions and expansions policy

3.6.1 Code requirements

Section 3.16 of the Code requires an access arrangement to have an extensions and expansions policy. The policy is to set out the method proposed to assess whether any extension to, or expansion of, the capacity of the pipeline will be treated as part of the covered pipeline (section 3.16(a)). If an extension or expansion is to be treated as part of the covered pipeline a service provider is also required to specify the impact on reference tariffs (section 3.16(b)). In relation to specifying the impact on reference tariffs, the extensions and expansions policy may:

- Provide for reference tariffs to remain unchanged with a surcharge levied on incremental users where permitted by sections 8.25 and 8.26 of the Code. Section 8.25 of the Code allows a service provider to elect by written notice to the regulator to recover all or part of an amount that it would not recover at the prevailing tariffs through a surcharge. Once written notice is received, the regulator may approve the surcharge following a public consultation process and provided the principles in section 8.26 of the Code apply; or
- Specify that a review will be triggered and that the service provider must submit revisions to the access arrangement pursuant to section 2.28 of the Code.

In addition, if a service provider agrees to fund new facilities where certain conditions are met, an extensions and expansions policy must provide a description of those new facilities and the conditions on which the facilities will be funded (section 3.16(c)).

The Code's requirements relating to new facilities investment are contained in sections 8.15 – 8.19 of the Code. Briefly, section 8.15 of the Code allows the capital base to be increased from the commencement of a new access arrangement period to recognise additional capital costs in constructing, developing or acquiring new facilities for the purpose of providing services, provided that the new facilities investment meets the criteria set out in section 8.16(a).

If the reference tariff policy allows the service provider to undertake new facilities investment which do not pass the requirements of section 8.16(a), then the portion of any such investment which does pass those requirements may be included in the capital base pursuant to section 8.18. The remainder (or a portion of it) may, if the reference tariff policy allows, be subsequently added to the capital base if it passes the section 8.16(a) requirements in the future (section 8.19).

Further discussion on new facilities investment can be found in section 2.3 of this *Final Decision*.

3.6.2 Original access arrangement

In its original access arrangement EAPL proposed that the capital base include the entire covered pipeline, as described in the Code, plus three nominated new facilities investments: the pipeline extension from Wagga Wagga to Culcairn (the Interconnect); the looping of a section of the Canberra lateral; and the Uranquinty compressor.[520]

EAPL did not expect any other new facilities to be constructed during the initial access arrangement period. However, EAPL noted that in the event that it did extend or expand the pipeline it would decide, with the consent of the Commission, whether this would be included as part of the covered pipeline. EAPL also proposed a surcharge for proposed projects where the NPV of the reference tariff was less than the NPV of the capital and operating costs of the new facilities plus a contribution for the use of existing facilities. The surcharge was designed to equate the NPV of both revenue and costs.

Clause 16.7 of EAPL's access arrangement also provided that any amount in the speculative investment fund which in the future satisfied section 8.16 of the Code, may be included in the capital base.

3.6.3 Commission's Draft Decision

In its consideration of EAPL's original extensions and expansions policy the Commission examined the concerns raised by Incitec[521], and its own concerns with the proposed policy.

One concern expressed by Incitec was the transparency of the process for including new facility expenditure in the capital base. The Commission acknowledged Incitec's concerns but noted that for any new facilities investment that EAPL would wish to include in the capital base, it would need to submit revisions to the access arrangement. The Commission also noted that any revisions to the access arrangement would need to be assessed in accordance with the public consultation process set out in section 2 of the Code and concluded this process provided for a suitable degree of transparency.

Incitec also expressed concern that although the NPV test proposed for the determination of the surcharge seemed appropriate, clear standards and procedures would be required for the implementation of the proposed surcharge. The Commission agreed that some clarification was required, particularly in relation to the discount rate used for the NPV analysis, and proposed that the appropriate discount rate for the NPV analysis was the vanilla WACC (proposed amendment A3.13).[522]

In reference to Incitec's comments on the inclusion of amounts recovered by a surcharge in the speculative investment fund, the Commission referred to section 8.26(b) of the Code and noted that this section would not permit any amounts recovered via a surcharge to be included in the speculative investment fund.

In addition, the Commission noted the absence of any mechanism to provide for the notification to the Commission of extensions or expansions to the MSP coming into service. As a result, the Commission proposed that EAPL notify the Commission prior

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[520] EAPL access arrangement information, 5 May 1999, clause 3.3.

[521] Incitec submission prepared by NERA, 15 July 1999.

[522] ACCC, *Draft Decision: MSP*, p. 165.

to the commencement of services provided through extensions to and expansions of the MSP (proposed amendment A3.12).

Finally, in relation to clause 16.7, the Commission stated that further clarification could be achieved by noting in the clause that in adding a recoverable portion to the capital base the Commission must be satisfied that the recoverable portion meets the tests set out in section 8.16 of the Code (proposed amendment A3.14).

3.6.4 Submissions in response to the Draft Decision

EAPL rejected the Commission's proposed amendment that it be required to notify the Commission in advance of any extensions and expansions that it does not intend to include in the access arrangement. According to EAPL, the proposed amendment was not necessary to enable the Commission to fulfil its role under the Code or for the access arrangement to comply with the Code. EAPL concluded that the:

> … inclusion of such a requirement will be an unnecessary intrusion of regulatory oversight into the operations and commercial management of the pipeline.[523]

EAPL also disagreed with the Commission's proposal that the vanilla WACC be used in determining the charges for any expansion of capacity. EAPL argued the provision would not take into account the differences in risk which arise between new and established facilities and in turn overlooked the Code requirement that the rate of return earned by a service provider should reflect the underlying risks of the investment.[524]

EAPL also made reference to proposed amendment 'A3.14: recovery of surcharge' and stated:

> …the Draft Decision proposes that clause 16.7 be amended to specifically provide for the Commission to approve the surcharge. As the Commission notes, this matter is already provided for in the Code and EAPL therefore submits that the amendment is not necessary.[525]

It appears that EAPL has misunderstood the Commission's proposed amendment to clause 16.7 (proposed amendment A3.14). Clause 16.7 had not related to the recovery of a surcharge but rather increasing the capital base by including portions of the speculative investment fund which later met the requirements of section 8.16 of the Code. It was this clause that the Commission proposed be amended.

3.6.5 Revised access arrangement

In its revised access arrangement EAPL has proposed to include the entire covered pipeline, as described in the Code, and the Interconnect from Wagga Wagga to Culcairn (which is treated as part of the mainline for the purpose of the access arrangement) in its capital base.[526] EAPL also nominated expansions to the capacity of

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[523] EAPL response to the Draft Decision, p. 29.

[524] EAPL response to the Draft Decision, p. 29.

[525] EAPL response to the Draft Decision, p. 30.

[526] EAPL revised access arrangement, 30 April 2002, clause 2.1.

the Northern lateral, Canberra lateral and Southern lateral.[527] However, since the submission of downwardly revised gas throughput forecasts, EAPL has reconsidered the nominated expansions and is now proposing only to construct an additional compressor on the Northern Lateral. The cost of this proposed expansion has been included in the forecast capital expenditure for the access arrangement period (see section 2.3) and will therefore affect reference tariffs in the period.

The relevant provisions of EAPL's extensions and expansions policy are contained in clause 14 of the revised access arrangement. Specifically, clause 14.1 provides that in the event that EAPL further extends the pipeline geographically or expands its capacity it proposes to decide, with the consent of the Commission, whether any such augmentation will be part of the covered pipeline.

Additional information provided to the Commission suggests that EAPL intends, where it is agreed with the Commission that an extension or expansion is to be covered, that the reference tariffs remain unchanged.[528] However, where the incremental revenue does not exceed the cost of new facilities investment a surcharge may be required from relevant users. If a surcharge is required EAPL proposes to make an application to the regulator under the Code at that time.

Clause 14.2 provides that EAPL may, after consultation with the Commission, include as part of the covered pipeline any new or existing pipeline acquired from another party. If the acquired pipeline is:

- already covered, EAPL proposes that the pipeline be included in the capital base at its value under its access arrangement as at the date of its inclusion; and
- not covered, EAPL proposes that the pipeline be included in the capital base at a value agreed between EAPL and the Commission, being not more than the depreciated optimised replacement cost of the pipeline and not less than its depreciated actual cost.

EAPL notes that its owner, APT, is considering including the CWP in the MSP. If this occurs EAPL proposes that the regional lateral tariff be adjusted to reflect the inclusion of the CWP and that the adjusted regional lateral tariff then apply to the CWP.[529]

In addition to these provisions, clause 8.6 of the revised access arrangement states that EAPL may undertake new facilities investment in the future that do not meet the requirements of the Code for inclusion in the capital base. Clause 14.3 further provides that any amount in the speculative investment fund which in the future satisfies section 8.16 of the Code, may be included in the capital base.

3.6.6 Submissions in response to the revised access arrangement

TXU asserted that all expansions to the MSP must be covered by an access arrangement. According to TXU, failure to do so may lead to operational issues on the

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527 EAPL revised access arrangement information, 7 July 2003, table 5.

528 EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 10.

529 EAPL revised access arrangement, 30 April 2002, p. 19.

pipeline including difficulties in distinguishing between those segments of the facility or pipeline which provide the original or expanded capacity.[530]

However, EAPL[531] rejected TXU's assertions and stated that the arguments presented were inconsistent with the wording of section 3.16 of the Code, which according to EAPL, clearly anticipates a future decision on coverage. EAPL stated that the approach it had adopted was consistent with other approved access arrangements and should be accepted by the Commission.

3.6.7 Commission's considerations

Examining EAPL's revised extensions and expansions policy, the Commission has in the first instance sought to ensure that the policy complies with section 3.16 of the Code before moving on to consider EAPL's proposals in relation to: the inclusion into the capital base amounts in the speculative investment fund; the Interconnect; and the acquisition of other pipelines.

Section 3.16(a)

As set out earlier, section 3.16(a) of the Code requires an extensions and expansions policy to outline either the method to be applied to determine whether an extension to, or expansion of, capacity will be treated as part of the covered pipeline or will not be treated as part of the covered pipeline.

The relevant provision within EAPL's revised access arrangement is clause 14.1, which states that EAPL will decide in future, with the consent of the Commission whether any new extension or expansion of the MSP will be part of the covered pipeline. The Commission has sought clarification from EAPL as to whether it will require the Commission's consent when determining whether an extension or expansion will not be part of the covered pipeline. EAPL[532] has submitted that the intention of the clause is that in the first instance it will decide whether or not the extension or expansion will be part of the covered pipeline. If EAPL independently decides that the augmentation will be part of the covered pipeline, EAPL proposes to approach the Commission for its consent to include the extension or expansion within the covered pipeline. While not explicitly stated by EAPL, it appears that if it decides not to cover an augmentation, it will not consult with or seek the consent of the regulator. It should be noted that the Commission's consent to include an extension or expansion within the covered pipeline would only be provided if the new facilities investment meets the conditions set out in section 8.16(a).[533]

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530 TXU submission, 24 July 2002, p. 7.

531 EAPL response to submissions, 25 September 2002, p. 5.

532 EAPL, response to the Commission, 14 October 2002.

533 See ACCC, *Final Decision: GasNet application for revision.*

As noted in previous decisions[534], the Commission has some concerns in relation to the ability of service providers to exercise sole discretion when determining whether an augmentation will not be included within the covered pipeline. The Commission acknowledges that in the event that a service provider elects not to treat an extension or expansion as part of the covered pipeline, an application may be made by any person to the NCC (sections 1.2 and 1.3 of the Code) to have the pipeline declared a covered pipeline under the Code.

Nevertheless, the Commission has some residual concerns that decisions to not include an extension or expansion within the covered pipeline may have implications for the economically efficient operation of the covered pipeline and in turn may be contrary to both the public interest and the interests of users and prospective users (sections 2.24(e) and 2.24(f)). In light of these concerns, the Commission has assessed EAPL's proposed policy for extensions and expansions taking into account the principles set out in section 2.24 of the Code.

In the case of expansions, the Commission has in previous decisions, such as the MAPS Access Arrangement and more recently in the ABDP Access Arrangement, outlined its concerns in relation to the potential for a service provider to exercise a degree of market power when the expansion does not form part of the covered pipeline. Specifically, these decisions have noted that in cases where a pipeline is operating at or near capacity a service provider may, in the absence of regulation and competition, be able to extract monopoly rents by pricing expansions just below the point where it would no longer be commercially viable for a user or prospective user to continue with its proposal.[535]

This ability to exercise a degree of market power in setting the terms and conditions, including tariffs, may in turn discourage investment and entry into downstream markets and in so doing produce an outcome that would be contrary to the public interest (section 2.24(f)). Where entry into downstream markets does occur, new entrants facing higher gas transportation costs may be unable to act as a competitive constraint on incumbents. The ability to extract monopoly rents will operate to limit effective competition in downstream markets and in turn limit any efficiency gains obtained. In addition to these factors, the ability of a service provider to capture monopoly rents that would otherwise be passed onto households and businesses in the form of lower prices, may impact on the economic growth of the region.

The culmination of these factors has led the Commission to conclude in previous decisions that where a pipeline is operating at or near capacity the: economically efficient operation of the covered pipeline (section 2.24(d)); the public interest, including the public interest in having competition in markets (section 2.24(e)); and the interests of users and prospective users (section 2.24(f)) requires that expansions to the pipeline should be covered, unless the regulator considers otherwise.

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534 ACCC *Final Decision: MAPS,* ACCC, *Final Decision: Access Arrangement proposed by APT Petroleum Pipelines Ltd for the Wallumbilla to Brisbane Pipeline System,* 16 January 2002, ACCC, *Final Decision: Access Arrangement proposed by Carpentaria Gas Pipeline Joint Venture for the Ballera to Mount Isa Pipeline*, 16 January 2002 and ACCC, *Final Decision: ABDP.*

535 ACCC *Final Decision: MAPS,* pp. 170-172 and ACCC, *Final Decision: ABDP*, pp. 152-153

In the case of EAPL's proposal, the Commission notes that the MSP currently has a substantial amount of excess capacity which when combined with its throughput forecasts suggests that the total MSP system is unlikely to approach capacity over the course of the initial access arrangement period. Within this environment it would appear unlikely that a service provider would expand the capacity of a pipeline. As set out earlier, however, EAPL has proposed to construct a backup compressor on the Northern Lateral to avoid forecast peak system constraints.[536] This is the only expansion of capacity expected to arise over the access arrangement period and the forecast costs of construction of this expansion have been included in EAPL's calculation of total revenue.

In view of the excess capacity currently prevailing on the MSP and given that EAPL has already proposed that the only expected expansion be covered, the Commission's concerns regarding coverage of expansions have to some extent been ameliorated. Accordingly, the Commission considers that EAPL's proposal with respect to expansions is appropriate in the current environment and is not currently contrary to the economically efficient operation of the covered pipeline (section 2.24(d)), the public interest (section 2.24(e)) or the interests of users and prospective users (section 2.24(f)). However, the Commission notes that if the pipeline approaches capacity in subsequent access arrangement periods, it may need to reassess the suitability of this policy. Also, the Commission notes that if EAPL decides not to include an expansion within the covered pipeline an application may be made by any person to the NCC to have the pipeline declared a covered pipeline under the Code.

In relation to extensions, the Commission has in previous decisions acknowledged that the barriers to entry for constructing extensions are lower than that for expansions. This may in effect limit the market power that a service provider may otherwise have. The distinction between the market power a service provider may have when constructing extensions or expansions lies in the differences in the economies of scale and scope available to the service provider in each situation. That is, a service provider's economies of scale and scope will be substantially greater when expanding a pipeline than when extending a pipeline. Lower economies of scale and scope may reduce the barriers to entry which in turn enables competition and diminishes the potential for market power to be exercised.

On this basis, the Commission considers that EAPL's proposal with respect to extensions is appropriate and is not necessarily contrary to the economically efficient operation of the covered pipeline (section 2.24(d)), the public interest (section 2.24(e)) or the interests of users and prospective users (section 2.24(f)). The Commission notes that if EAPL decides not to include an extension within the covered pipeline an application may be made by any person to the NCC to have the pipeline declared a covered pipeline under the Code.

Section 3.16(b)

Section 3.16(b) of the Code requires an extensions and expansions policy to specify how any extension or expansion, which is to be treated as part of the covered pipeline,

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[536] EAPL consolidated information based on questions from the Commission, 8 April 2003.

will affect reference tariffs. EAPL has identified one forthcoming expansion of the MSP that it intends to carry out during the initial access arrangement period – the installation of a compressor on the Young to Lithgow (or Northern) lateral. In accordance with section 8.20 of the Code, EAPL proposed that reference tariffs be determined on the basis of the forecast costs of this new facility. The Commission's assessment of EAPL's proposal is contained in the section of this *Final Decision* dealing with forecast capital expenditure (section 2.3).

While specifying how the proposed Northern Lateral expansion will affect reference tariffs, EAPL's revised access arrangement does not provide any detail as to how reference tariffs will be affected by any additional investment in new facilities. EAPL has, however, in further correspondence with the Commission stated:

> It is intended that where it is agreed with the regulator that an extension or expansion is to be covered, the reference tariffs will remain unchanged. However where the incremental revenue does not exceed the cost of new facilities investment, a surcharge may be required. EAPL will determine whether such a surcharge is required and make an application to the regulator under the Code at that time. [537]

The way in which a surcharge will be calculated has not been specified by EAPL. This aspect would be considered once an application from EAPL is received. Thus, the Commission's proposed amendment A3.13 is no longer relevant.

The statement noted above reflects sections 3.16(b)(i) and 8.25 of the Code. However, it is not currently incorporated in the revised access arrangement. The Commission therefore requires an amendment to the access arrangement to incorporate a provision which reflects the example set out in section 3.16(b)(i) of the Code.

Amendment FDA 38

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the extensions and expansions policy to state that where an extension or expansion is to be treated as part of the covered pipeline, the reference tariffs will remain unchanged but EAPL may elect by written notice to the regulator to recover all or part of an amount that it would not recover at the prevailing tariffs through a surcharge. A surcharge may be levied on incremental users where permitted by the Code.

Speculative investment fund

Clause 14.3 of EAPL's revised access arrangement states that any amount in the speculative investment fund may subsequently be added to the capital base if in the future it satisfies section 8.16 of the Code. This clause is identical to clause 16.7 of the original access arrangement and in turn mirrors section 8.19 of the Code. In its *Draft Decision*, the Commission proposed that clause 16.7 be amended to require EAPL to obtain the Commission's approval to include any amount satisfying section 8.16 of the Code within the capital base (proposed amendment A3.14). This issue is more relevant

537 EAPL consolidated information based on questions from the Commission, 8 April 2003, p. 10.

to the reference tariff policy and consequently further discussion is located at section 2.3 of this *Final Decision*.

The Interconnect

A key issue for the Commission is the method EAPL intends to include the Interconnect in the capital base. In the original access arrangement, EAPL proposed that the Interconnect be regarded as an extension to the covered pipeline and included within the capital base for tariff setting purposes (sections 3.4 and 16.1). Specifically, clause 16.1 stated:

> EAPL's Capital Base includes all of the Pipeline as well as the following New Facilities Investments:
>
> - looping of a section of the Canberra lateral; and
> - the pipeline extension between Wagga Wagga and Culcairn (for the purposes of this Access Arrangement and the Code, the pipeline extension between Wagga Wagga and Culcairn, owned and operated by EAPL is treated as an extension to the Covered Pipeline and has been included in the Capital Base).

These provisions have not been replicated within the revised extensions and expansions policy and there are no other express provisions within the revised access arrangement which expressly provide for the inclusion of the Interconnect in the capital base. However, it appears clear that clauses 2.1, 2.2, 2.3 and 8.5 of the revised access arrangement, with other submissions made by EAPL (including estimations of the initial capital base, its service policy and tariff models), demonstrate EAPL's intention that the Interconnect is to form part of the covered pipeline.

The Commission has raised this with EAPL. EAPL responded by informing the Commission that the decision as to whether the Interconnect should be incorporated within the covered pipeline through the extensions and expansions policy (pursuant to section 1.40 of the Code) was clouded by its current application for revocation of coverage on the mainline and Canberra lateral segments of the MSP.[538] EAPL noted that if its application for the revocation of coverage on the mainline was successful then it would see no benefits arising from the Interconnect being 'covered'. Conversely, EAPL stated that if the application was unsuccessful then it intended that the Interconnect form part of the covered pipeline.

EAPL submitted that if the Interconnect were to be included as a part of the covered pipeline then an appropriate mechanism for this would be the provisions contained within the original access arrangement. However, EAPL also stated that flexibility should be built into the access arrangement so that if the relevant minister decides to revoke coverage then the Interconnect should not be covered.[539]

While EAPL has referred to the need to incorporate flexibility into the access arrangement in regard to the Interconnect, it has not provided any specific clauses for the access arrangement. The Commission has examined whether any flexibility could

[538] EAPL letter to the Commission, 15 August 2003.

[539] EAPL letter to the Commission, 15 August 2003.

be incorporated into the access arrangement. However, the Commission understands that the Code does not provide for such flexibility on issues relating to coverage. That is, while section 1.40 of the Code provides that an extension to the covered pipeline shall be treated as part of the covered pipeline if provided for in the extensions and expansions policy, section 1.24 of the Code makes it clear that the decisions relating to the revocation of coverage can only be made by the relevant minister. Consequently, if EAPL decides at this time to include the Interconnect within the covered pipeline (by virtue of its extensions and expansions policy) then any later decision on its part to unwind this would require EAPL to lodge an application with the NCC for coverage to be revoked on that segment of the covered pipeline (section 1.24 of the Code).

Ultimately, the decision as to whether or not the Interconnect should be included within the extensions and expansions policy is one to be made by EAPL. However, for the purposes of this *Final Decision*, the Commission has undertaken its assessment on the basis that the Interconnect does form part of the covered pipeline. This decision is consistent with clauses 2.1, 2.2, 2.3, 8.5 of the revised access arrangement and with other submissions made by EAPL including its estimation of the initial capital base, forecast operating expenditure, tariff models and service policy. To clarify the status of the Interconnect the Commission requires the following amendment to the extensions and expansions policy. Further discussion on the Interconnect can be found in section 2.2 of this *Final Decision.*

Amendment FDA 39

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the extensions and expansions policy to provide that the pipeline from Wagga Wagga to Culcairn is part of the Covered Pipeline.

The Commission notes that if EAPL decides not to include the Interconnect in the capital base then it must also address the other provisions and aspects of the access arrangement which provide for the inclusion of the Interconnect. These provisions include, but are not limited to:

- clauses 2.1, 2.2, 8.5 and attachment A of the revised access arrangement to remove any references to the Interconnect;
- submit a revised value of the ICB; and
- submit revised forecast operating costs and SIB capital expenditure.

Acquisition of pipelines

EAPL's proposed revised extensions and expansions policy also provides for the acquisition of existing pipelines from another party. There are two key aspects to this proposal:

- the acquisition of an existing pipeline which is already the subject of an access arrangement; and
- the acquisition of a new or existing pipeline which is not currently the subject of an access arrangement.

In relation to the first, EAPL has proposed that the acquired pipeline should be included in the capital base at its value pursuant to the relevant access arrangement. EAPL has also foreshadowed the merger of the CWP and the MSP and a subsequent adjustment to the regional lateral tariff. The Commission notes that this provision was drafted prior to the introduction of sections 2.4A and 2.28A into the Code.[540] However, the Commission's assessment of this proposal must be made with reference to these new Code provisions.

Pursuant to section 2.4A of the Code a service provider may (if the regulator agrees and subject to any conditions that the regulator may require, having regard to the matters set out in section 2.24) submit a single access arrangement for two or more covered pipelines that have the same regulator and service provider. If a single access arrangement is submitted in accordance with section 2.4A:

- the covered pipelines that are the subject of that access arrangement will be treated as a single covered pipeline for all purposes under the Code; and
- the regulator may not (unless the service provider agrees) require the service provider to submit separate access arrangements for those covered pipelines under section 2.4.

Furthermore, section 2.28A provides that if the regulator agrees, proposed revisions submitted by a service provider under section 2.28 may apply to one or more covered pipelines that have the same regulator and service provider. If this section applies:

- the reference tariffs principles described in section 8 of the Code apply in the aggregate to all of the covered pipelines that are the subject of the proposed revisions; and
- the covered pipelines that are the subject of that access arrangement will be treated as a single covered pipeline for all purposes under the Code.

Accordingly, the Commission considers that if at any time in the future EAPL seeks to merge two or more covered pipelines (such as the CWP), which are both regulated by the Commission, it should do so in accordance with either section 2.4A or section 2.28A. The method by which the capital base will be adjusted to take into account the acquired covered pipeline will be determined in accordance with the principles set out in section 8.9 of the Code. That is, the capital base of both covered pipelines at the start of the immediately preceding period would be adjusted for any new facilities investment which satisfies section 8.16(a) of the Code less any redundant capital and depreciation for the immediately preceding access arrangement period.

Second, where the acquired pipeline is not subject to an access arrangement EAPL has proposed it that it may, after consultation with the regulator, incorporate the pipeline into the capital base of the covered pipeline at a value agreed with the regulator, being not more than the depreciated optimised replacement cost of the pipeline and not less than its depreciated actual cost (clause 14.2).

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[540] National Third Party Access Code for Natural Gas Pipeline Systems: Sixth Amending Agreement, 29 April 2003.

The Commission notes that no specific details have been provided by EAPL. However, such an acquisition is in effect a new facilities investment in accordance with the expanded definition of new facilities following the seventh amendment to the Code in April 2003.[541] As such, the provisions of the Code relating to new facilities investment (sections 8.15 to 8.27) would apply. If EAPL were to acquire another pipeline it would, in accordance with section 8.15 of the Code, be able to increase the capital base of the MSP from the commencement of a new access arrangement period provided the new facilities investment satisfies the requirements of section 8.16(a). The requirement that the investment would have to satisfy section 8.16(a) precludes the Commission from agreeing to simply roll in a value of the new pipeline (something between the depreciated optimised replacement cost and depreciated actual cost) into the capital base and pass on the cost to all users.

Despite this the Commission notes that there are a number of alternatives available to EAPL should it acquire an uncovered pipeline, which it wants to form part of the covered pipeline. For instance, if the acquisition is planned ahead of the commencement of an access arrangement period EAPL may, in accordance with section 8.20 of the Code, include the acquisition as forecast capital expenditure. The Commission would then assess whether the new facilities investment is reasonably expected to pass the requirements of section 8.16(a).

Alternatively, if the acquisition is unplanned and occurs once an access arrangement period has commenced EAPL may voluntarily submit revisions to the access arrangement (pursuant to section 2.28) at any time. The Commission would then assess the proposed revisions in accordance with the public consultation process set out in section 2 of the Code.

Finally, the Commission notes that if EAPL wishes to obtain some certainty as to whether the acquisition of the uncovered pipeline will be likely to satisfy the requirements of section 8.16(a), it may at any time under section 8.21 of the Code approach the Commission and ask it to consider whether the investment meets the requirements of section 8.16(a). Before giving any agreement under this section, the Commission must undergo public consultation in accordance with the requirements for a proposed revision to the access arrangement submitted under section 2.28 of the Code.

In conclusion, the Commission considers that in both the scenarios foreshadowed by EAPL (acquisition of covered and uncovered pipelines) there are adequate provisions within the Code to deal with the merger of two pipelines.[542] Moreover, these Code provisions operate to ensure that the service provider's legitimate interests and investment in the covered pipeline are considered (section 2.24(a)) as well as the interests of users and prospective users (section 2.24(f)) through the public consultation processes. Accordingly, the Commission considers that the provisions of the Code negate the need for the inclusion of these two scenarios within clause 14.2.

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[541] New facilities investment is defined in section 8.15 of the Code as additional capital costs incurred in the construction, development or acquisition of new facilities.

[542] The Commission notes that these are recent provisions to the Code which did not exist at the time EAPL lodged its access arrangement.

Once these two scenarios are removed then only the first sentence of clause 14.2 remains. The Commission notes that in light of the Commission's proposal to remove the term 'new' from clause 14.1 the amended clause would render this sentence superfluous. As a result, the Commission requires clause 14.2 to be removed from EAPL's revised access arrangement.

Amendment FDA 40

In order for EAPL's access arrangement for the MSP to be approved, EAPL must remove clause 14.2 from the revised access arrangement.

The *Draft Decision* included an amendment requiring EAPL to notify the Commission prior to the commencement of services provided through the extension or expansion of the MSP (proposed amendment A3.12). The Commission rejects EAPL's contentions that the such a requirement is an unnecessary intrusion of regulatory oversight into the operations and commercial management of the pipeline. Nevertheless, on further consideration of the issue the Commission no longer requires this amendment.

3.7 Review and expiry of the access arrangement

3.7.1 Code requirements

Section 3.17 of the Code requires an access arrangement to include a date upon which the service provider must submit to the regulator a revised access arrangement (revisions submission date) and a date upon which the revisions are intended to commence (revisions commencement date).

Pursuant to section 3.17, when approving the revisions submission date and the revisions commencement date the regulator must have regard to the objectives contained in section 8.1 of the Code. Having done so, the regulator may require an amendment to the proposed access arrangement to include earlier or later dates. The regulator may also require that a specific major event be defined as a trigger that would oblige the service provider to submit revisions prior to the revisions submission date (section 3.17(ii)).

An access arrangement period accepted by the regulator may be of any duration. However, if the period is greater than five years, the regulator must consider whether mechanisms should be included in the access arrangement to address the potential risk that forecasts, on which terms of the proposed access arrangement are based, subsequently prove to be incorrect (section 3.18 of the Code). The Code provides the following examples of mechanisms that may be adopted: triggers for early submission of revisions based on divergence of the service provider's profitability or the value of services reserved in contracts; or changes to the type or mix of services provided (section 3.18(a)); and the return of some or all revenue or profits in excess of a certain amount to users (section 3.18(b)).

Finally, it should be noted that the revisions commencement date is not a fixed date but is determined by the regulator at the time at which it approves the revisions pursuant to section 2.48 of the Code. This section states that:

> Subject to the Gas Pipelines Access Law, revisions to an Access Arrangement come into effect on the date specified by the Relevant Regulator in its decision to approve the revisions (which date must not be earlier than either a date 14 days after the day the decision was made or ... the Revisions Commencement Date).

3.7.2 Original access arrangement

In its original access arrangement EAPL proposed to submit revisions to the access arrangement to the Commission on or before 1 January 2005. The revisions were to commence either six months after this date or on the date on which the Commission's approval of the revisions were to take effect under the Code, whichever was the later.

3.7.3 Commission's Draft Decision

The Commission noted that although EAPL's proposal for the revisions submission was consistent with the Code, in practice the proposed term would result in an initial access arrangement period of closer to four years than five. The Commission stated that a more appropriate length of time for an initial access arrangement period for a pipeline such as the MSP would be five years. This term would provide EAPL with a greater degree of regulatory certainty as well as a reasonable time to benefit from incentive mechanisms incorporated into the access arrangement. Accordingly, the Commission proposed that the revisions submission date be amended to four years and six months from the date of commencement of the initial access arrangement (amendment A3.15), which would effectively bring the expected length of the access arrangement to five years. The Commission did not consider that triggers for specifying an early review of the access arrangement were necessary.[543]

3.7.4 Submissions in response to the Draft Decision

The EUAA stated that it supported the proposal that the revisions submission date be four years and six months from commencement of the initial access arrangement.[544]

Similarly, EAPL stated that it had no objection to increasing the revisions submission date to four years and six months from the date of commencement of the initial access arrangement.[545]

3.7.5 Revised access arrangement

Clause 4.1 of the revised access arrangement states that the access arrangement will come into effect on either 1 October 2002 or a date specified by the regulator, as long as it is after 1 October 2002. EAPL propose in clause 4.2 to submit revisions to the access arrangement on either 1 December 2007 or five years after the date the regulator deems that the access arrangement comes into effect. In addition, clause 4.3 states that revisions to the access arrangement would commence either seven months after the revisions submission date or on the date that the Commission approves as the commencement of the revised access arrangement.

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543 ACCC, *Draft Decision: MSP*, p. 167.

544 Energy Users Association of Australia submission, 21 February 2001, p. 2

545 EAPL submission, 14 March 2001, p. 29

Given that the provisions relating to 1 October 2002 are no longer valid, the above clauses result in a proposed length of the access arrangement period of at least five years and seven months.

3.7.6 Commission's considerations

EAPL's revised proposal for the revisions submission date is consistent with section 3.17 of the Code in that it includes a date upon which it must submit revisions to the access arrangement and a date upon which those revisions are intended to commence.

However, the Commission has some concerns in relation to the length of the initial access arrangement period proposed by EAPL. Specifically, in accordance with section 3.17 of the Code, the Commission has considered the proposed minimum access arrangement period length of five years and seven months against section 8.1 provisions, and does not consider that the proposed duration of the access arrangement period is appropriate. There are three key reasons for this conclusion:

- First, a number of the WACC parameters (risk free rate and debt margin) are based on the assumption that EAPL will operate under an access arrangement period which is approximately five years in length. If the access arrangement period is significantly longer than five years, then EAPL may not receive an adequate return on its investment. While EAPL has proposed an access arrangement period of five years and seven months, the Commission acknowledges that the regulatory period may be extended significantly beyond this duration should the assessment of revisions take longer than the estimated period of seven months. Consequently, EAPL may not be able to recover efficient costs (section 8.1(a)), the inadequate return may distort investment decisions in pipeline transportation systems (8.1(d)) and the outcomes may not reflect that expected from a competitive market (section 8.1(b)).
- Second, assuming a commencement date of 1 January 2004, an access arrangement period of five years and seven months would expire on 31 July 2009 at the earliest and potentially much later, compared to the Commission's proposed expiry date of 31 December 2008. As EAPL has only provided public data relating to the period 1 October 2002 to 30 June 2008, interested parties have not had the opportunity to comment on information covering the additional time proposed to be included in the access arrangement period. The Commission's analysis of total revenue and reference tariffs are also based on the five year period. This lack of information and transparency may have an adverse impact on the efficiency in the level and structure of the reference tariffs (section 8.1(e)) and may also distort investment decisions in upstream and downstream industries in accordance with section 8.1(d) of the Code.
- Third, a five year access arrangement period should provide EAPL with appropriate performance incentives, particularly if the rolling carryover mechanism proposed in this *Final Decision* is adopted by EAPL in its amendments (in accordance with section 8.1(f) of the Code).

In addition, the Commission notes that in its submission to the *Draft Decision* EAPL did not object to the Commission's proposal to bring the expected length of the access arrangement period to five years.[546] The proposal in the revised access arrangement is inconsistent with this earlier view.

The Commission also has a number of concerns with the revisions assessment period of seven months proposed by EAPL. While the Commission initially accepted six months in the *Draft Decision*, it now considers (based on recent experience) that it would be appropriate to extend the assessment period to twelve months in duration. As discussed in chapter four of this *Final Decision*, the initial access arrangement assessment process has to date taken in excess of one year and four months since the submission of the revised access arrangement in May 2002. While a number of exogenous events such as the revised AGL contracts have delayed the process, the Commission considers that the complexity of the material and delays imposed by EAPL has also played an important role.

In light of the recent history with regard to assessing the proposed MSP access arrangement, the Commission regards a longer assessment period commencing four years after the start of the access arrangement period will minimise the risk that the access arrangement period will extend significantly beyond five years. As noted above, an access arrangement substantially in excess of the five year period may be contrary to section 8.1 reference tariff objectives, such as the ability of the service provider to earn a stream of revenue that recovers efficient costs (section 8.1(a)) and on efficiency incentives (section 8.1(f)). Furthermore, uncertainty with regard to the access arrangement revisions dates may not be in the interests of users and prospective users who may require information pertaining to revised reference tariffs and terms and conditions in advance of the expected commencement date. That is, this uncertainty may further contribute to potential distortion of investment decisions (8.1(d)) and may also undermine replication of competitive market outcomes (8.1(b)). Uncertainty may also adversely impact on financing, hedging and other arrangements that may be pursued by the service provider, which may conflict with section 8.1(a) of the Code. In accordance with the above discussion, the Commission requires the following amendment:

Amendment FDA 41

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 4.2 of the revised access arrangement to state that EAPL will submit revisions to the access arrangement together with the applicable access arrangement information (as required under sections 2.28 of the Code) 4 years after the date this access arrangement comes into effect.
>
> EAPL must also amend clause 4.3 to state that the revisions to this access arrangement will commence on the latter of 12 months after the Revisions Submissions Date or the date on which the approval of the revisions takes effect.

Implementation of the above amendment will result in an initial access arrangement period of at least five years, although it may exceed this in the event that the revisions assessment process exceeds the anticipated 12 months. Section 3.18 of the Code states

[546] EAPL response to the Draft Decision, March 2001, p. 30.

the Commission must not approve access arrangements of greater than five years without considering whether such mechanisms should be included to address the risk that forecasts on which the terms of the access arrangement were based and approved, may prove incorrect. The Commission has considered the revisions submission date and the impact of specifying any triggers for an early review of the access arrangement and does not consider that such mechanisms are warranted in this instance. As a risk management tool against a number of exogenous cost changes within the access arrangement period, EAPL has proposed a form of pass through in its revised access arrangement (see section 2.10 for further discussion). In any event EAPL is able to lodge revisions to any part of the access arrangement period prior to the revisions submission date in accordance with section 2.28 of the Code

4. Key performance indicators

4.1.1 Code requirements

The Code identifies the need for KPIs to be disclosed by service providers to interested parties. Category 6 of Attachment A of the Code lists the following relevant items:

- industry KPIs used by the service provider to justify 'reasonably incurred' costs; and
- the service provider's KPIs for each pricing zone, service or category of asset.

Section 8.6 of the Code allows the regulator to 'have regard to any financial and operational performance indicators it considers relevant in order to determine the level of costs within the range of feasible outcomes under section 8.4 that is most consistent with the objectives contained in section 8.1'. The regulator must then identify the indicators and provide an explanation of how they have been taken into account (section 8.7 of the Code).

4.1.2 Original access arrangement

EAPL originally submitted a number of KPIs to demonstrate that its performance compared favourably with other gas pipelines. EAPL also commissioned Ernst and Young to assess its costs against 15 participating companies from the USA, Canada, UK, Brazil, Argentina, Indonesia and New Zealand. This study provided indicators on:[547]

- total expenses per km;
- general and administrative expenses per volume-distance;
- operating and maintenance expenses less fuel per km; and
- total expenses per volume-distance.

EAPL also commissioned Foster Associates Incorporated to compare tariffs per 1 000 km for firm transportation services in North America against EAPL's tariffs. A comparison of operating costs for a number of Australian pipelines was also made against EAPL's costs on a $m/1 000 km basis.[548]

According to EAPL, the KPI data provided confirmed that the company 'compares favourably with other pipeline operations internationally in many cost related studies'.[549]

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547 EAPL access arrangement information, May 1999, pp.63-65 and EAPL, supplementary access arrangement information, 28 October 1999, pp. 42-45

548 EAPL access arrangement information, 5 May 1999, p. 65.

549 EAPL access arrangement information, 5 May 1999, p. 63.

4.1.3 Submissions in response to the original access arrangement

Innovative Energy on behalf of Incitec prepared a submission on the KPI data submitted by EAPL. This submission was critical of the benchmarking studies carried out by Foster Associates Incorporated, as well as the benchmarking of Australian operating costs presented by EAPL. With regard to the benchmarking studies completed by Foster Associates, Innovative Energy noted several 'pitfalls' of benchmarking, some of which it argued appeared to be evident in the information presented. These included distortions due to embedded variables, inappropriate massaging of information, the manipulation of data through the selection of worst performers in the sample and an apples and oranges comparison.[550]

With regard to the operating cost benchmarking, Innovative Energy argued that gas pipeline operating costs were sensitive to the number of compressors installed and operating on any given pipeline, since compressor fuel is a major cost component. Innovative Energy noted that given the MSP has little compression in comparison with other pipelines, it is inevitable that EAPL's costs will be lower than other pipelines. Innovative Energy stated that such comparisons revealed little about the performance of EAPL in relation to world's best practice.[551]

Despite these problems, Innovative Energy argued that benchmarking of important performance indicators may be informative if performed correctly. Innovative Energy argued that similarities between Australia and Canada facilitate comparisons between Canadian gas pipelines and Australian gas pipelines. Innovative Energy compared tariffs (on the basis of $/GJ/1 000 km) of various pipelines serving the Western Canadian Sedimentary Basin (WCSB) with the 2001 tariffs proposed by EAPL for the MSP.

Innovative Energy provided a number of normalised benchmarks of Canadian pipeline tariffs. Specifically, Innovative Energy provided benchmarks on various pipeline paths between the WCSB and various markets as well as tariffs on specific pipeline assets. In both of these scenarios, most of the tariffs quoted by Innovative Energy fell within the range of $0.30 to $0.50 GJ/1 000 km compared with $0.54 GJ/1 000 km for EAPL (for the initial year of the access arrangement period). Table 4.1.3.1 provides the data presented by Innovative Energy on normalised tariffs between the WCSB and major markets.

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550 Incitec submission, 18 August 1999, p. 3.

551 Incitec submission, 18 August 1999, p. 4.

Table 4.1.3.1: Comparison of average Tariff, $/GJ/1 000 km

Pipelines	Distance (km)	$/GJ/1 000 km
MSP	1 299	0.54 (Aus $)
Alberta to Central Canada	3 500	0.36 (Canadian $), April 1998
Alberta to Niagara Falls	3 800	0.34 (Canadian $), April 1998
Alberta to California Border	1 600	0.41 (Canadian $), April 1998
BC to California Border	2 200	0.48 (Canadian $), April 1998

Source: Incitec submission, 18 August 1999.
Note: Based on a 100% load factor.
On 1 April 1998, one Australian dollar was equivalent to $0.93 Canadian dollars.

EAPL's response to submissions

In response to Innovative Energy that the data had been manipulated to show the MSP in a favourable light, EAPL argued that it is common to benchmark performance on some standardised denominator and compare each organisation's performance against the standard.[552] EAPL argued that normalisation of data is an essential practice in the development of comparable surveys.

With regard to the claim by Innovative Energy that fully compressed pipelines have higher operating costs, EAPL agreed but asserted that the benchmarking data presented excluded compressor fuel in order to provide a more valid comparison of operating costs. In addition, EAPL argued that depreciation had been eliminated from some of the benchmarks to remove distortions caused by differences in depreciation practices.

EAPL discussed the claim made by Innovative Energy that Canadian pipelines typically have lower transmission tariffs than the MSP. EAPL stated:

> Clearly there are a number of similarities between Canada and Australia but a major point of difference is the scale of the gas industry, including the transmission sector, in the two countries. The fundamental flaw in the Incitec submission is that it ignores the very significant influence of economies of scale in comparing pipelines in the two countries. The submission points out that Canada's annual gas production is five times that of Australia (p 5, 8th dot point) and that is a broad indicator of the scale difference. A number of Canadian pipelines have an annual throughput many times that of the EAPL system.[553]

EAPL added that significant economies of scale arise on gas pipelines as a result of a number of factors, such as: the construction costs being proportional to length; the strong relationship between the length of the pipeline and operating costs; and the high proportion of fixed costs associated with pipelines which means that smaller diameter pipelines are relatively more expensive to construct per unit of capacity.[554] To illustrate this point, EAPL provided an example of costs for a hypothetical uncompressed pipeline 1 000 km in length, and demonstrated that as pipeline diameter and throughput increased, tariffs also decreased significantly given the underlying influence of economies of scale.

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552 EAPL response to submissions, 17 August 2000, p. 14.

553 EAPL response to submissions, 17 August 2000, p. 14.

554 EAPL response to submissions, 17 August 2000, pp.14-15.

4.1.4 Commission's Draft Decision

The Commission noted in the *Draft Decision* that it recognised the limitations of KPIs. Despite these shortcomings, the Commission noted that KPI analysis provided a mechanism for service providers to justify reasonably incurred costs.

With regard to the KPIs submitted by EAPL the Commission acknowledged the criticisms made by Innovative Energy (on behalf of Incitec). The Commission also acknowledged the argument that tariff comparisons with Canadian pipelines was a more appropriate benchmark measure. The Commission observed that the amendments proposed in the *Draft Decision* would result in a reduction in EAPL's proposed tariffs and that the resulting mainline tariff compared favourably with the tariff of those companies used by Innovative Energy as benchmarks.

4.1.5 Submissions in response to the Draft Decision

There were no submissions received in response to the *Draft Decision* from interested parties on this issue.

4.1.6 Revised access arrangement

In its revised access arrangement information, EAPL asserted that there are significant limitations to performance benchmarking. EAPL submitted that despite the increasing amount of data available to regulators, the traditional difficulty of normalising pipelines to yield meaningful comparisons remains, given the extremely diverse characteristics of pipelines such as size and terrain. In addition, EAPL argued that benchmarking can only provide a broad indication of whether pipeline costs lie within the 'ballpark' of costs that are efficient.[555]

EAPL asserted that the primary operating cost driver for pipelines is the length of the pipeline, whilst the number and size of compressors and the number and size of off-take stations are secondary drivers of costs. EAPL further noted that the size of a pipeline (diameter) has at most some minor impact on operating costs. EAPL stated that generally the replacement cost of a pipeline (or as a proxy ORC) provides an index that incorporates all of these factors: length, the impact of compressors, off-take stations and diameter.[556]

EAPL argued that items such as throughput and pipeline capacity were not significant drivers of operating costs and thus should not be used as measures of performance.

Accordingly, EAPL argued that the generally accepted KPIs used by industry are:

- Operating costs per kilometre of pipeline length; and
- Operating costs as a percentage of pipeline capital cost (ORC)

EAPL added that measures which are misleading and should not be used are:

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555 EAPL revised access arrangement information, 7 July 2003, p. 43.

556 EAPL revised access arrangement information, 7 July 2003, p. 44.

- Operating costs per TJ annual throughput; and
- Operating costs per km length per TJ of annual throughput.

With regard to the operating costs as a percentage of ORC, EAPL argued that the overall MSP ratio is 2.2 per cent, which is consistent with the Commission's expected ratio for partially compressed pipelines, and is in line with pipelines of similar size, terrain and levels of compression. EAPL added that with regard to the operating costs per kilometre, the ratio of $11 400 per km is within the range accepted by regulators. EAPL provided the following data based on the operating cost values approved by regulators.

Table 4.1.6.1: Benchmarking operations costs for Australian gas transmission pipelines submitted by EAPL (2001)

	MSP		MAPS		GasNet		GGT		DBNGP		ABDP	
	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000 /km	% ORC	$000 /km	%ORC	$000/ km	% ORC	$000 /km
2000							2.3	7.5	1.7	16.8		
2001			2.4	14.4			2.2	7.2	1.6	16.4		
2002			2.3	13.8			2.2	7.2	1.8	18.5	1.7	3.7
2003	2.2	11.3	2.3	13.9	3.6	14.6	2.2	7.2	1.8	18.2	1.7	3.7
2004	2.2	11.5	2.3	13.8	2.5	9.9	2.4	7.8	1.8	17.8	1.7	3.7
2005	2.2	11.4	2.3	13.8	2.4	9.6					2.0	4.4
2006	2.2	11.4			2.5	10.1					1.7	3.7
2007	2.2	11.4			2.5	10.1						
2008	2.2	11.4										

Source: EAPL, Revised Access Arrangement Information, 7 July 2003, p. 46.

EAPL also asserted that the most appropriate comparison or benchmark pipeline for the costs of the MSP is the GasNet system. This is because the GasNet system has a comparable number of off-takes, but is considerably shorter in length and does not suffer many of the geographic access characteristics of the MSP. The total GasNet system operating costs are approximately $20 million, however, this does not include significant activities undertaken by VENCorp.

EAPL argued that to conduct a meaningful comparison, the GasNet system costs should also include at least a portion of VENCorp's costs. If only 50 per cent of VENCorp's charges are added to the GasNet system's costs, the total costs are approximately $30 million for the GasNet system. This compares to total operating costs of about $23 million for the MSP. EAPL argued that in light of the Commission's recognition that GasNet and VENCorp's operating expenditures are efficient, the Commission should be consistent in its decisions and approve the operating expenditure for the MSP.[557]

[557] EAPL revised access arrangement information, 7 July 2003, p. 46.

4.1.7 Submissions in response to the revised access arrangement

There were no submissions received from interested parties on this issue.

4.1.8 Commission's considerations

As argued in the *Draft Decision*, the Commission is aware of the limitations of benchmarking and KPI comparisons. As suggested by EAPL, limitations include the impact of different pipeline characteristics on outcomes, such as size and terrain. Other limitations include the uncertainties of adjustments (such as fuel costs) and the fact that some performance indicators do not capture all relevant information (such as the fact that operating costs depend on the extent of capital expenditure and vintage of the assets). Despite these limitations, the Commission considers that KPIs provide an important mechanism to corroborate the legitimacy of costs proposed by service providers.

As noted above, EAPL argued in its revised access arrangement information that the GasNet system provides an appropriate benchmark pipeline for the costs of the MSP on the basis that it has a comparable number of off-takes and does not suffer many geographic access constraints. In addition, EAPL asserted that costs on the GasNet system should include a portion of VENCorp's costs for the operation of the pipeline. The Commission, however, questions the validity of EAPL's claims. The Commission is aware from information contained in EAPL's access arrangement information that there are approximately 40 off-take points on the MSP, including those on the Griffith and Northern Laterals. This compares to over 100 off-take points along the GasNet system.[558] Moreover, it is unclear how differences in geographical access makes like with like comparisons between the two pipelines possible. In addition, with regard to the system operation costs incurred by VENCorp, the Commission notes that these costs are likely to be significantly higher in Victoria given that it operates under a market carriage gas transportation system. Inclusion of even 50 per cent of VENCorp's costs may vastly overstate the costs of the Victorian system when compared against the MSP.

Accordingly, the Commission does not consider that direct comparisons can be made between the MSP and GasNet operating systems, even when taking into account a portion of the system operation costs incurred by VENCorp. Alternatively, the Commission considers that it is appropriate to develop normalised indicators for comparison of MSP costs with those incurred by GasNet as well as other Australian transmission pipeline systems.

To this end, EAPL has submitted two comparative cost performance benchmarks with its revised access arrangement: operations costs/ORC and operations costs per km. These benchmarks supersede the six indicators submitted in EAPL's initial access arrangement which were total expenses per km (including total expenses less depreciation); general and administrative expenses per volume-distance; operating and maintenance expenses less fuel per km; total expenses per volume-distance; tariffs per 1 000 km and operating costs per1 000 km.

[558] From www.GasNet.com.au

There is extensive debate regarding the efficacy of different unit cost KPI measures. For example, with regard to the ABDP access arrangement, the Power and Water Corporation argued that the comparison of operating costs between pipelines on a dollar per 1 000 km basis is 'overly simplistic' and 'meaningless'.[559] In its submission relating to the GasNet access arrangement, Energy Advice proposed that comparison of costs on a dollar per TJ per kilometre basis is appropriate.[560] In addition, the Commission is of the opinion that three KPI measures are more useful for the comparison of transmission pipeline operating performance:

- Total revenue per GJ of gas per km transported (revenue per GJ per km). This indicator provides a measure of how well the company is performing after allowing for the volume of and distance over which the gas is transported. This measure is better than the transmission tariff, however, it is sensitive to the asset value of the pipeline and its utilisation as measured by load factors. This normalisation can also be applied to specific costs, such as non capital costs.
- Operating and maintenance costs per km (operating costs per km). While this measure recognises that non capital costs are a function of distance, it is also influenced by terrain and the level of investment in new technology.
- Capital costs per km per mm of new construction (capital costs per km per mm). This provides a measure of how well the company manages its new construction and the effect of technological change.

The Commission is aware of the debate surrounding the reasonableness of different performance indicators, however, it is of the view that the provision of a variety of KPIs can elucidate the cost claims made by service providers. That said, the Commission considers that the KPIs provided by EAPL are not adequate for this purpose.

Given this inadequacy the Commission has re-calculated the KPIs originally submitted by EAPL (with the exception of tariffs per 1 000 km)[561] and has also calculated the indicator non capital costs (less compressor maintenance costs) per GJ per kilometre. These indicators have been calculated by comparing information provided by EAPL in its initial and revised access arrangement information against data on costs approved by regulators for other Australian gas transmission pipelines. For comparative purposes, the average cost data calculated excludes information on the MSP. The results of this analysis are illustrated in the table and graphs below for 2004.

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559 Clayton Utz, 17 November 1999, NT Government and PWC submission to the ACCC on Access arrangement for the Amadeus Basin to Darwin Gas Pipeline, p. 8.

560 Energy Advice submission, GasNet Australia access arrangement revisions for the Principal Transmission System, 30 May 2002.

561 Tariffs per 1 000 km has been excluded given that different tariff paths across access arrangements and tariffs on different pipeline segments makes comparison between pipelines difficult.

Table 4.1.8.1: Additional KPI data for EAPL (nominal 2004 data)

Pipeline	Total expenses per km[a]	Total expenses (less deprec) per km[b]	General and admin per TJ per km [c]	Operating costs (less fuel) per km [d]	Non capital costs (less fuel) per 1 000 km[e]	Total expenses per km per PJ	Non capital costs (less compressor maintenance and fuel) per km per PJ[f]
GasNet system[g]	37 927	26 896	0.019	5 394	9.62	169	0.03
MAPS[h]	50 211	47 026	N/A	N/A	14.93	395	0.12
DBNGP[i]	119 303	94 435	N/A	N/A	16.53	214	0.03
Goldfields[j]	44 223	36 681	0.115	4 590	7.50	1756	0.30
ABDP[k]	28 233	17 925	0.049	4 338	5.28	1765	0.33
CWP[l]	12 322	N/A	0.967	1 996	3.21	9818	2.56
MSP original AA[m]	48 775	35 131	0.024	5 239	7.04	543	0.07
MSP revised AA[n]	44 714	43 875	0.029	9 337	12.07	469	0.13
Average[o]	**48 703**	**44 593**	**0.288**	**4 080**	**9.72**	**2353**	**0.56**
Median[p]	**41 075**	**36 681**	**0.082**	**4 464**	**8.56**	**1076**	**0.21**

Notes:

a. Incorporates operating costs, capital costs, tax payments, return on capital and depreciation

b. Incorporates operating costs, capital costs, tax payments and return on capital.

c. General and administrative costs include marketing and overhead costs

d. Operating costs include all operating costs such as pipeline and compressor maintenance less general and administration, marketing and fuel gas costs.

e. Non capital costs in this instance are total operating costs (operating and maintenance costs and general and administrative Costs) excluding fuel gas costs. As noted above, this indicator was also calculated by EAPL. EAPL's calculation generated the same relative ranking of the pipelines as the Commission's assessment.

f. Compressor maintenance costs not known for the MAPS, Goldfields Gas Pipeline System, and ABDP.

g. ACCC, *Final Decision: GasNet*, 13 November 2002, pp. 137, 204, 208. GasNet Australia access arrangement information, 27 March 2002, p. 2.

h. ACCC, *Final Decision: MAPS*, 12 September 2001, pp. 56, 16, 31, xiii, Epic access arrangement information, clause 17.1.

i. Independent Gas Pipelines Access Regulator of WA, *Final Decision: Dampier-Bunbury Gas Pipeline*, 23 May 2003, pp. 79, 88, 123; Epic Energy proposed Access Arrangement Information, 28 July 2000, pp. 11, 61.

j. Independent Gas Pipelines Access Regulator of WA, *Draft Decision Access Arrangement Goldfields Gas Pipeline*, 10 April 2001, Part A p. 21; Part B pp. 18, 83, 115, 117, 161, 164.

k. ACCC, *Final Decision: ABDP,* 4 December 2002, pp. 69, 98, 106, 108; NT Gas access arrangement information, 8 February 1999, pp. 18-19.

l. ACCC, *Final Decision: CWP*, 30 June 2000, pp. 74, 77, 78; AGL Pipelines access arrangement information, 8 February 1999, p. 19.

m. EAPL access arrangement information, 5 May 1999, pp. 3-4, 83, 89, 91. Financial year data.

n. EAPL revised access arrangement information, 7 July 2003, p. 16, 22, 25, 40. Financial year data.

o/p. Does not include MSP KPI data.

Figure 4.1.8.1: Total expenses ($)/km ($nominal 2004)

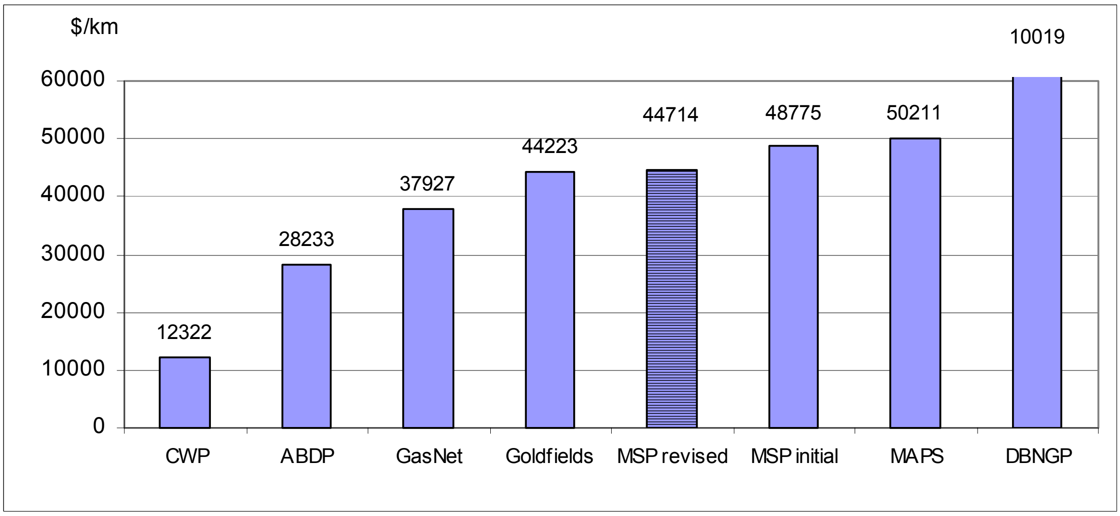


Figure 4.1.8.2: Total expenses less depreciation ($)/km ($nominal 2004)

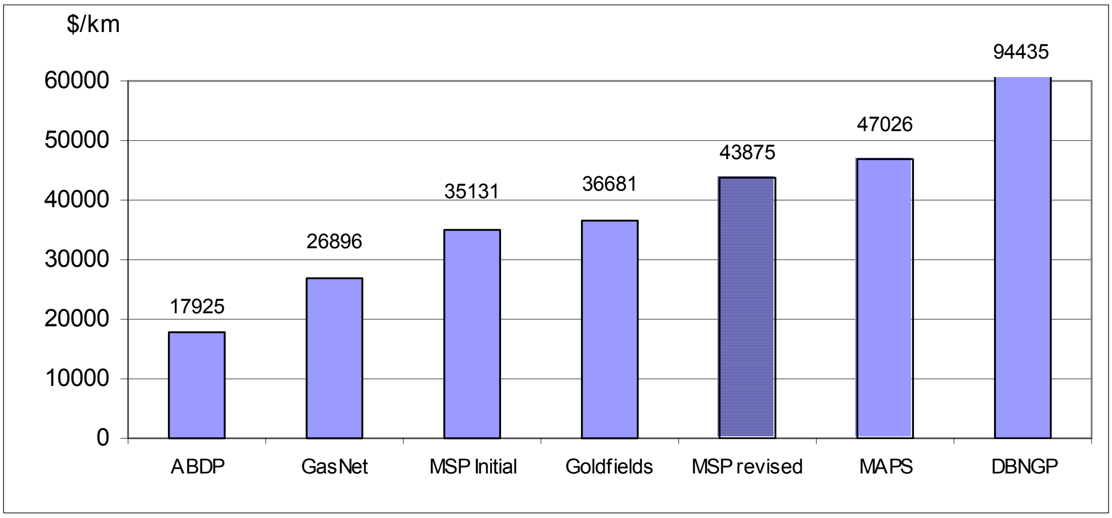


Figure 4.1.8.3: General and administrative costs/TJ/km ($nominal 2004)

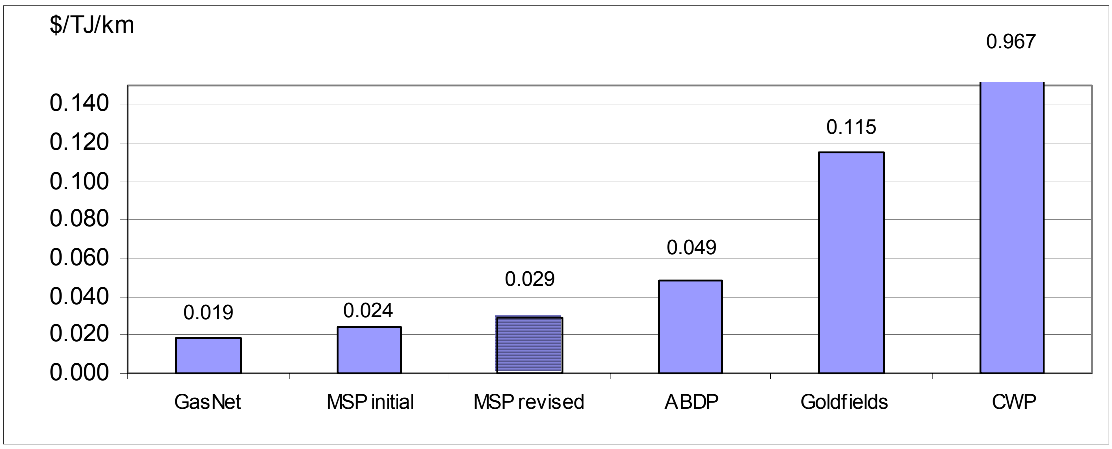


Figure 4.1.8.4: Operating and Maintenance costs (less fuel gas)/km ($nominal 2004)

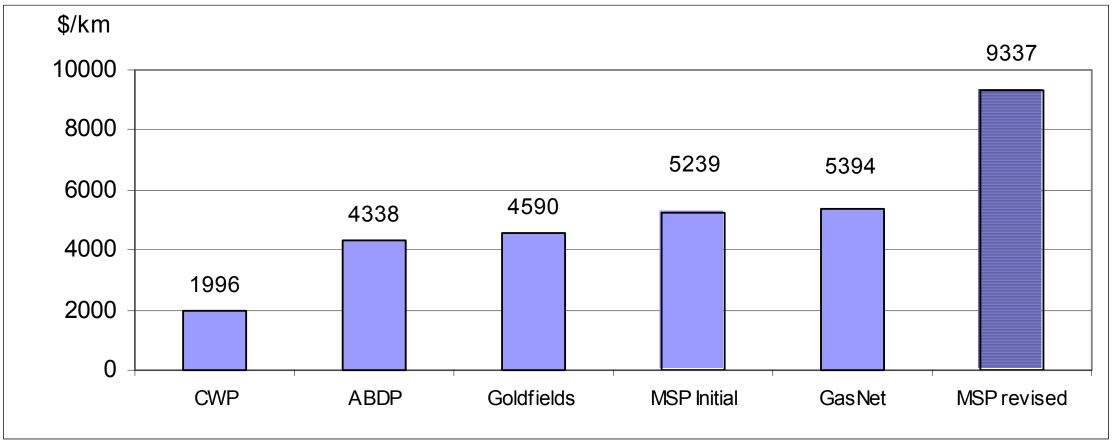


Figure 4.1.8.5: Non capital costs (less fuel gas)/km ($nominal 2004)

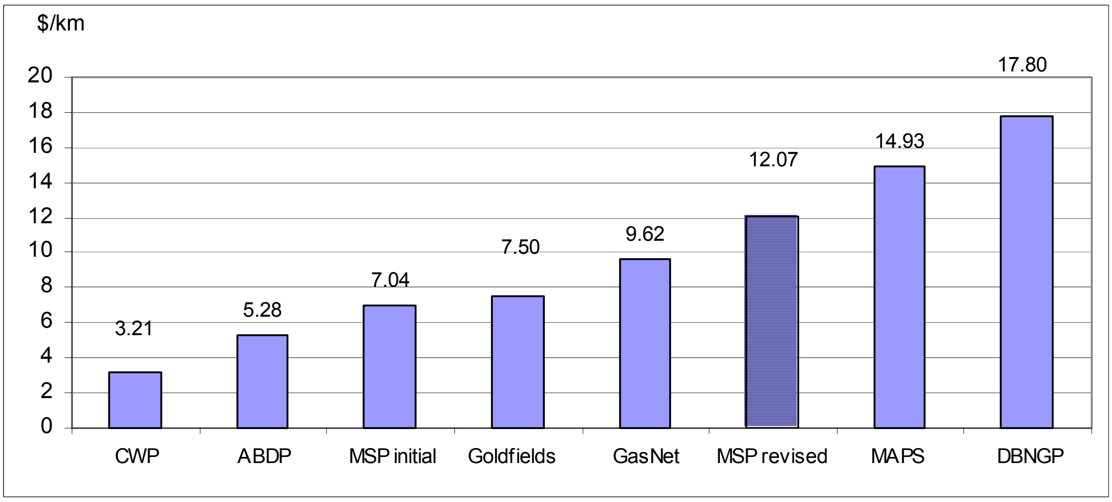


Figure 4.1.8.6: Total expenses/km/PJ ($nominal 2004)

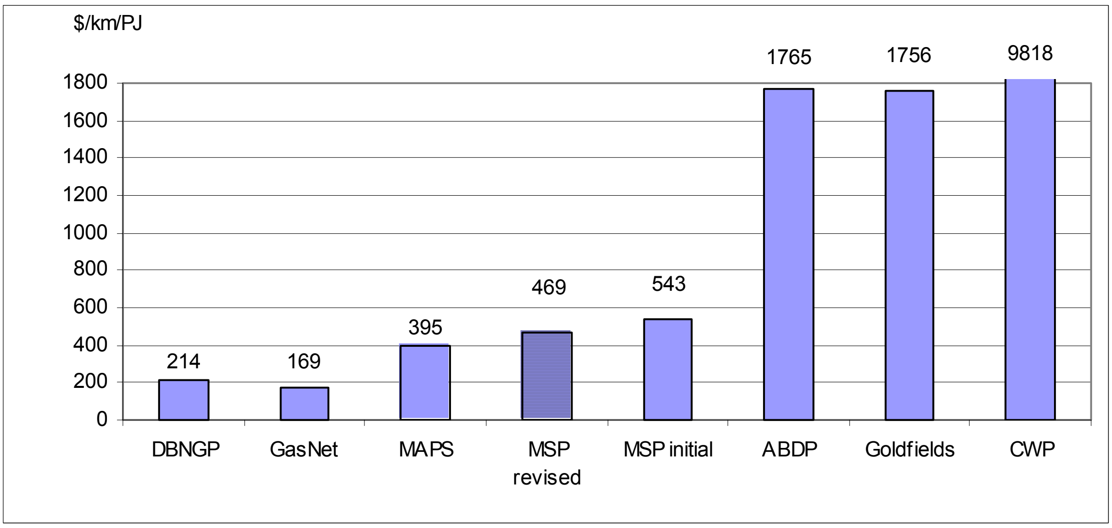
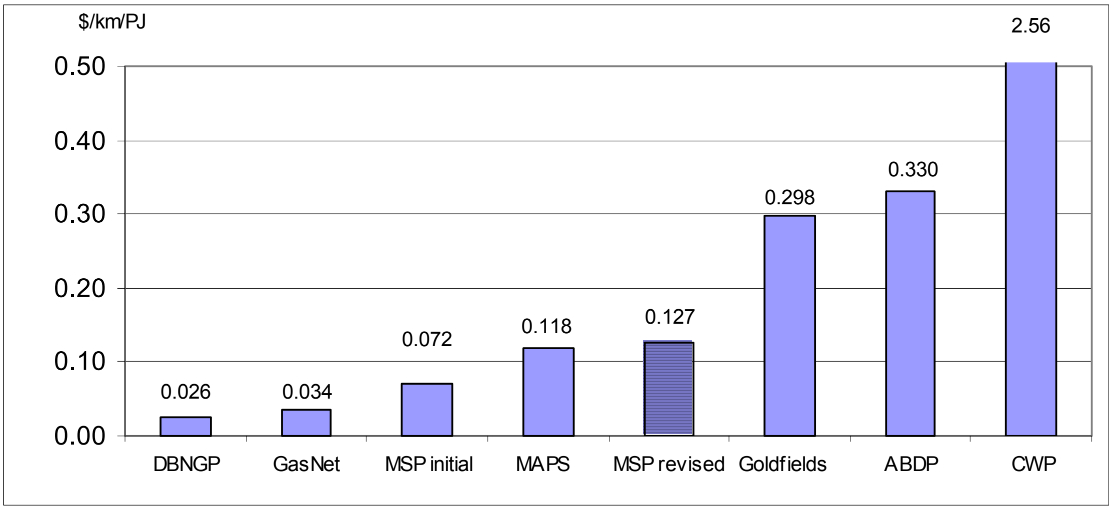


Figure 4.1.8.7: Non capital costs (less compression and fuel costs)/km/PJ ($nominal 2004)



As the above data demonstrates, EAPL's expenditure falls in the middle of the range on some indicators and is at the high end of the range on several other KPIs.

Total expenses KPIs

With regard to total expenses, EAPL's revised costs are the fourth highest on a per kilometre basis and are close to the pipeline average. This outcome is in part a consequence of the very high total expenses per km exhibited by the DBNGP, which has costs more than double those found on other Australian transmission systems. EAPL also has the third highest total costs per km net of depreciation. With regard to this indicator, EAPL sits near the average of $44 593/km and substantially above the median.

As noted above, total revenue per GJ per km provides a good indicator of how the company is performing against what it does: transporting energy over defined distances. EAPL's performance against this indicator is in the middle of the range and its costs are below the average and median figures. However, the pipelines that have costs higher than EAPL on this indicator, the CWP, ABDP and Goldfields Gas Pipeline, may be characterised as unique for two main reasons.

First, these three pipelines have relative low forecast throughput relative to total pipeline expenses. For example, the ABDP has forecast costs in excess of $45 million in 2004, but throughput volumes are forecast to be only 16 PJ in that year. In contrast, the MAPS has forecast costs of $52.5 million, but is estimated to transport a total of 127 PJ in the year 2004. Low volumes on these pipeline systems may in part be explained by relatively small diameter compared to the others in the sample. The mainline on the ABDP has a diameter of 356 mm, the CWP has a diameter of 168 mm and the Goldfields Gas Pipeline has a diameter of 350-400 mm. This compares to the MSP mainline which measures 864 mm and the MAPS which has a diameter of 559 mm.[562] Second, the three pipelines that have costs in excess of EAPL in terms of

[562] Source: Gas Code, Schedule A.

total revenue per GJ per km are also party to the PMA. As discussed in section 2.8 of this *Final Decision*, a substantial part of the PMA, which is an agreement between APT pipelines and Agility Management, is made up of fixed costs. As the Commission has suggested, these agreed costs may not reflect the efficient operation of the respective pipelines, thereby leading to the inflation of non capital costs and thus total expenses.

Operating costs

With regard to operating costs, EAPL performs relatively well in terms of general and administrative costs (which includes overheads and marketing expenses). Specifically, EAPL exhibits the highest operating and maintenance costs in the lower mid-range relative to the sample, and is substantially below the average. The Commission notes that this result may in part be the outcome of the exclusion of different cost drivers from this category compared to other pipeline systems.

On the other hand, EAPL performs poorly with regard to operating costs less fuel gas costs (which broadly constitutes pipeline and compressor maintenance costs). It exhibits the highest operating and maintenance costs per kilometre relative to other pipelines and is substantially above the median and mean results. This clearly corroborates the Commission's concern with the costs proposed by EAPL that were noted earlier in this *Final Decision*. However, it should be noted that information pertaining to the DBNGP and MAPS were not available for this indicator. Moreover, the inclusion of different cost drivers in this category from the general and administrative category may effectively inflate EAPL's costs compared to others in the sample.

EAPL also perform below average when total non capital costs per km are compared. EAPL's costs of $12.07/km are significantly higher than the average ($9.72/km) and median ($8.56/km), and EAPL has the third highest total operating costs per 1 000 kilometres. EAPL ranks only below DBNGP and MAPS, both of which are characterised by a large number of compressor stations which, as noted previously, add substantial costs to the operation of a pipeline system. This result supports the claim made in section 2.7 of this *Final Decision* that operating costs proposed by EAPL may not correspond with those that would be incurred by a prudent service provider acting efficiently in accordance with sections 8.36 and 8.37 of the Code.

To provide further insight into the operating costs proposed by EAPL, the Commission has calculated non capital costs per km per GJ. The Commission has excluded compressor maintenance costs from the DBNGP, the MSP and the GasNet system to establish a more appropriate like-with-like comparison of non capital cost expenses. Compression maintenance costs have not been excluded from the MAPS, ABDP and the Goldfields Gas Pipeline as such a breakdown was not available for analysis. Further, the CWP does not face such costs given that it does not have any compressors installed on its system.

As discussed with regard to total expenses, KPIs based on costs per PJ per km provide a good indicator of how the company is performing in the delivery of its service. Whilst EAPL claimed that indicators that are based on costs per distance per volume are misleading and should not be used, it did not provide any reasoning in support of its position.[563]

Against this KPI, the MSP ranks in the middle of the range, and is below the average and median figures. However, as with total expenses per PJ per km, the MSP is outperformed by the ABDP, the Goldfields Gas Pipeline and the CWP, all of which are characterised by relatively small diameter, relatively small gas throughput and are party to the PMA. What is illustrated from this indicator is that non capital costs on the MSP are higher than those on comparable pipelines, namely the DBNGP, the GasNet system and the MSP (which is actually inflated given the inclusion of compressor maintenance costs). Accordingly, this benchmark also supports the view that EAPL's costs may exceed those that would be incurred by an efficient and prudent service provider.

Conclusion

The Commission reiterates that it is aware of the limitations of benchmarking studies, and concurs with EAPL that the traditional difficulty of 'normalising' pipelines remains. As illustrated in the preceding discussion, comparison of pipelines is inherently difficult given such different pipeline characteristics as pipeline diameter, number of compressors, throughput, number of off-takes, different system operation mechanisms and so on. However, the Commission considers that the KPIs noted above in relation to operating costs per 1 000 km, non capital costs per km and non capital costs per km per PJ provide broad evidence in support of the Commission's concerns with EAPL's proposed operating and maintenance cost requirements. As discussed, the Commission considers that the indicator operating costs per kilometre provides a good indication of an asset's relative performance, whilst non capital costs per kilometre-distance illuminate total non capital costs associated with delivering one PJ of gas to users.

563 EAPL revised access arrangement information, 7 July 2003, p. 45.

5. Decision

The Commission has considered EAPL's proposals and submissions by interested parties. The Commission has explicitly commented on the issues and arguments raised where this has been considered appropriate.

The Commission has weighed the sometimes conflicting interests in accordance with the principles set out in the Code. In particular, it has been mindful of the requirement to take into account the factors set out in section 2.24 and where appropriate section 8.1. The Commission's considerations of these assessments are summarised in earlier sections of this *Final Decision*.

Pursuant to section 2.16(b)(ii) of the Code, the Commission has decided not to approve the proposed access arrangement for the Moomba to Sydney Pipeline System lodged by East Australian Pipeline Limited. The Commission's reasons for this decision are provided earlier in this *Final Decision* document.

The amendments (or the nature of amendments, as appropriate) that would have to be made in order for the Commission to approve the proposed access arrangement are identified in the relevant sections of this *Final Decision* document and are listed below. EAPL must submit amended revisions to the Commission by 23 October 2003.

Amendment FDA 1

> In order for EAPL's proposed access arrangement for the MSP to be approved, the value of the ICB must be set at $559.3 million (real 2002/03).

Amendment FDA 2

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.4 to clarify that actual capital expenditure must satisfy the requirements of the Code before it is added to the capital base.

Amendment FDA 3

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.6 by adding that only that portion of the new facilities investment which satisfies the requirements of the Code may be added to the capital base.

Amendment FDA 4

> In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 14.3 to state that an amount in respect of the balance after deducting the recoverable portion of new facilities investment may subsequently be added to the capital base, with the approval of the Commission, if at any time the type and volume of services provided using the increase in capacity attributable to the new facility changes such that any part of the speculative investment fund would then satisfy the requirements of section 8.16(a).

Amendment FDA 5

In order for EAPL's access arrangement for the MSP to be approved the provision contained in clause 14.3 of EAPL's proposed access arrangement (as amended according to this *Final Decision*) must be deleted from the extensions and expansions policy and inserted into the reference tariff policy.

Amendment FDA 6

In order for EAPL's access arrangement for the MSP to be approved, the reference tariff policy must be amended to allow the Commission, at the commencement of the subsequent access arrangement period, to review and, if necessary, adjust the capital base for wholly or partially redundant assets.

Amendment FDA 7

In order for EAPL's access arrangement for the MSP to be approved, EAPL must adopt the depreciation schedule contained in Table 2.5.7.1 of this *Final Decision*.

Amendment FDA 8

In order for EAPL's access arrangement for the MSP to be approved the WACC estimates and associated parameters forming part of the access arrangement and access arrangement information must be amended to reflect the current financial market settings by adopting the parameters set out by the Commission in Table 2.6.7.7 of this *Final Decision*. The calculation of total revenue must reflect these parameters.

Amendment FDA 9

In order for EAPL's access arrangement for the MSP to be approved, EAPL must adopt the non capital costs set out in Table 2.7.8.2 of this *Final Decision*.

Amendment FDA 10

In order for EAPL's access arrangement for the MSP to be approved, EAPL must adopt the total MSP throughput forecasts contained in Table 2.8.7.2 of this *Final Decision*.

Amendment FDA 11

In order for EAPL's access arrangement for the MSP to be approved, EAPL must:

- include details of the price path adjustment mechanism in its access arrangement document;
- use September quarter data as the basis of the annual CPI adjustment in 2004 through to 2007;
- specify that the annual CPI adjustment would come into effect on 1 January for the years 2005 through 2008; and
- specify that forecast inflation will be used to calculate tariffs in the first year of the access arrangement period.

Amendment FDA 12

In order for EAPL's access arrangement for the MSP to be approved, EAPL must include the following provisions into the access arrangement:

- EAPL must provide a notice to the Commission of its proposed revised tariffs in accordance with the reference tariff formula and approved X values 30 days business days prior to 31 December 2004 and each subsequent year until 31 December 2007.
- This notice must specify that the proposed variations to the reference tariff applies from 1 January of the relevant year.
- The Commission will assess the proposed tariffs provided by EAPL and determine if they comply with the relevant CPI-X formula. The Commission will publish its decision within 20 business days of EAPL lodging its submission. The Commission may either approve the revision, disallow the variation or may specify a complying variation. If a complying variation is required, this will be taken to be approved on the 21st business day after lodgement and come into effect on 1 January of the relevant year.
- If the Commission does not provide a notice within 20 business days, the Commission will be taken to have approved the revised tariffs, which will come into effect on 1 January of the relevant year.
- Before the expiry of the 20 business days after submission, the Commission may request additional information if it considers that such information will assist its assessment. This will extend the relevant assessment period by the number of days commencing on the day on which the Commission gave notice to EAPL and ending on the day on which EAPL submits the required information.
- The Commission may grant an extension on application by EAPL of any of the time periods associated with this process.

Amendment FDA 13

In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace the tariffs proposed in Attachment C1 with those set out in Table 2.9.1.4. EAPL must also delete Attachments C2, C3 and C4 from the revised access arrangement.

Amendment FDA 14

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 8.7 of its revised access arrangement to specify that taxes and charges incorporated in the pass through are exogenous, of pronounced magnitude and affect the regulated firm disproportionately. In addition, EAPL must amend clauses 8.7 of its revised access arrangement to take into account the financial impact of the removal of taxes, charges, levies, duties imposts or fees.

Amendment FDA 15

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 6.13 of the revised access arrangement to specify that:

- any new legal or procedural requirements related to FRC result from either: the introduction of a new law relating to retail contestability; stipulated in a direction of a relevant Minister; or stipulated by a body appointed to implement retail contestability in the gas industry;
- that the financial impact of the event must be of a pronounced magnitude; and
- the event must affect the company disproportionately.

EAPL must also amend clause 6.13 to allow for both positive and negative changes in FRC costs.

Amendment FDA 16

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clauses 8.7 and 6.13 to clarify that the financial impact of a pass through is incurred in the initial access arrangement period and that any claim does not include costs accepted under a previous pass through submission or in approved regulated revenues. Only the cumulative financial impact of a pass through may be claimed.

Amendment FDA 17

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 6.13 of its revised access arrangement to specify that the financial impact of FRC can only be recovered through reference tariffs. EAPL must also remove from clause 6.13 any reference to variations of the terms of Transportation Agreements.

In addition, EAPL must amend clauses 8.7 and 6.13 of its revised access arrangement as follows:

- EAPL must provide a written notice to the Commission specifying that a pass through event has occurred, the scope of the financial impact, how the claim is consistent with the pass through mechanism, the proposed variations to the reference tariff and an effective date for the changes.
- EAPL must provide for a minimum 40 day assessment period for any pass through claims submitted to the Commission. This period may be extended by the Commission should it seek further information from EAPL.
- EAPL must submit only one pass through notice a year, which must be submitted at least 50 days prior to the end of each financial year. This notice may incorporate a number of pass through claims or may specify that no specific events defined in the reference tariff policy have occurred.
- EAPL must state that it can apply for an extension of the relevant assessment period and that the Commission may extend the time period in the situation that it has proposed its own revisions to reference tariffs.
- EAPL must specify that the Commission can initiate its own pass through review.

Amendment FDA 18

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clauses 6.13 and 8.7 to state that EAPL must provide the Commission with documentary evidence (if available) which substantiates the financial impact of the pass through event. EAPL must use best endeavours to ensure that such information is available to the Commission.

Amendment FDA 19

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 7.5 to state that EAPL will:

- Provide a written notice to the Commission specifying the minimum distance for the calculation of lateral tariffs and demonstrate how this policy complies with section 8.1 of the Code.
- Provide for a minimum 40 day assessment period by the Commission which may be extended by the Commission should it seek further information from EAPL.
- Specify that the proposed changes will be deemed approved within the variation period, unless the Commission notifies EAPL that is does not approve the pass through claim or proposes a relevant variation to the proposal.
- State that it can apply for an extension of the relevant assessment period and that the Commission may extend the time period in the situation that it has proposed its own revisions to reference tariffs.

Amendment FDA 20

In order for EAPL's access arrangement for the MSP to be approved, the access arrangement must define 'insolvency event' as referred to in clauses 61 and 63 of Attachment D.

Amendment FDA 21

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 77(f) of Attachment D to state that the transfer not affecting the operational and technical requirements necessary for the safe and reliable operation of the pipeline.

Amendment FDA 22

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the obligation to rectify provisions contained within the revised Attachment E and in particular clauses 2(b) and 6(b).

For clause 2(b) EAPL must amend the provision to state that if the user's imbalance is in excess of the imbalance limit for four consecutive days, EAPL may purchase gas to correct a user's negative imbalance, and the user will be liable for a charge equal to the actual purchase price of the gas.

For clause 6(b) EAPL must amend the provision to state that in the case of a negative imbalance, correct the imbalance by purchasing gas at the receipt point and charging the user the amount paid by EAPL for that gas (which will be treated as gas supplied by the user at the receipt point). EAPL will notify the user promptly after it corrects an imbalance in this manner.

Amendment FDA 23

In order for EAPL's access arrangement for the MSP to be approved, EAPL must include a provision within Attachment E stating that EAPL may vary the balancing provisions contained in Attachment E without having to submit revisions to the access arrangement only if the variations are consistent with any government approved scheme put in place by the industry.

Amendment FDA 24

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend Attachment C5 to state the user may be liable to pay imbalance charges as set out in Attachment E.

Amendment FDA 25

In order for EAPL's access arrangement for the MSP to be approved, EAPL must remove the following statement from Attachment G 'If such specification is not published, then gas must meet the specification reasonably established by EAPL' and amend the Standards Australia number to state AS 4564.

Amendment FDA 26

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 23 of Attachment D to state that EAPL and the user must each notify the other as soon as they become aware of gas received at the receipt point or leaving the delivery point failing to meet the specification.

In the event that EAPL becomes aware of non-specification gas being received at the receipt point or leaving the delivery point it will notify any other user who may be affected.

Amendment FDA 27

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 24 of Attachment D to state that:

a. the user will indemnify EAPL for any loss, cost, expense or damage which arises out of or in connection with the receipt by EAPL from or on behalf of the user of any quantity of unauthorised non-specification gas at a receipt point (including direct, indirect and consequential loss); and

b. EAPL will indemnify the user for any loss, cost, expense or damage which arises out of or in connection with EAPL's express authorisation for the delivery of non-specification gas by a user into the pipeline (including direct, indirect and consequential loss).

Amendment FDA 28

In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace clauses 12.26(c) and 12.26(d) with a provision stating that prior to EAPL being obliged to enter into a transportation agreement, the prospective user must have met the prudential requirements set out in clause 12.8 of the access arrangement.

Amendment FDA 29

In order for EAPL's access arrangement for the MSP to be approved, EAPL must replace clause 76(h) of Attachment D with a provision stating the prospective user meeting the prudential requirements set out in clause 12.8 of the access arrangement.

Amendment FDA 30

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 1(a) of Attachment D to state that EAPL will be entitled to require a user to provide security for the performance of its obligations under a transportation agreement as set out in clause 81 of the access arrangement.

Amendment FDA 31

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 4(b) of Attachment C5: Overrun Charges to state the distance calculated from the applicable receipt point to the delivery point at which the overrun occurred.

Amendment FDA 32

In order for EAPL's access arrangement for the MSP to be approved EAPL must amend clause 73 of Attachment D to state:

Unless agreed by the parties and set out in the transportation agreement, any liability of either party will be limited to direct losses only, and does not extend to any consequential loss, loss bought by third parties or loss of business or other income, except where such damage or loss arises out of:

a. gross negligence or wilful misconduct by either EAPL or the user;

b. the delivery of unauthorised non-specification gas into the pipeline;

c. the failure by the user to deliver gas within a specified pressure range;

d. an unauthorised overrun by the user;

e. liability of EAPL arising due to the user's imbalances; or

f. failure by EAPL to maintain the safety and integrity of the pipeline.

73A However, neither party will be liable for loss which could have been mitigated against or for loss suffered as a result of contributory negligence on the part of the other party.

Amendment FDA 33

In order for EAPL's access arrangement for the MSP to be approved, EAPL must:

- Amend clause 6.10 to remove references to the order of priority of services;
- Amend clause 9.2 to state that Negotiable Services will have a priority agreed to in a non-discriminatory manner on a case by case basis with the priority agreed to not being higher than the Firm Service;
- Amend clause 10.1 to state that if any interruption or reduction of services occurs, the order of priority will be determined in a non-discriminatory manner with the Negotiable Service not having a higher priority than the Firm Service;
- Amend clause 54 of Attachment D to state that subject to any pre-existing contractual right to a higher priority, if there is any interruption or reduction of services or inability to meet transport obligations or force majeure affecting the services, then to the extent practicable, EAPL will provide services in a non-discriminatory manner with the Negotiable Service, including non-firm services under pre-existing contracts, not having a higher priority than the Firm Service; and
- Include the following definition within Attachment A, 'Non-Discriminatory Manner' means that EAPL will act in a manner which is consistent for each service offered and between each service offered, subject to differences which arise from legitimate economic, commercial and technical considerations.

Amendment FDA 34

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 59 of Attachment D to state that in the event of interruption or curtailment of services as a result of a force majeure claimed by EAPL, the user will be relieved from liability to pay the capacity and throughput charge, but will not be relieved from liability to pay any other charge.

EAPL must also amend clause 60 of Attachment D to state that the capacity charge and throughput charge relief will be pro-rated to the reduction in the user's MDQ at the time the user's MDQ is reduced following the occurrence of the force majeure and terminating at a time when the user's MDQ is no longer affected by the force majeure.

Amendment FDA 35

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 65 of Attachment D to state that EAPL will be entitled to assign its rights or obligations under the transportation agreement, without the prior consent of the user, to any person who holds an interest in the pipeline or to a related body corporate within the meaning of the *Corporations Act 2001* on the proviso that the assignee is capable of performing the obligations under the transportation agreement. In any other circumstance EAPL will not be entitled to assign its obligations under the transportation agreement without the prior consent of the user (with such consent not to be unreasonably withheld).

Amendment FDA 36

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 77 of Attachment D by replacing the term 'intending user' with the term 'transferee'.

Amendment FDA 37

In order for EAPL's access arrangement for the MSP to be approved, clause 12.23 must be amended to provide that the reference service and negotiated service have equal priority, subject to a prospective user seeking the reference service at the reference tariff having priority over a prospective user seeking the reference service at a tariff less than the reference tariff.

Amendment FDA 38

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the extensions and expansions policy to state that where an extension or expansion is to be treated as part of the covered pipeline, the reference tariffs will remain unchanged but EAPL may elect by written notice to the regulator to recover all or part of an amount that it would not recover at the prevailing tariffs through a surcharge. A surcharge may be levied on incremental users where permitted by the Code.

Amendment FDA 39

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend the extensions and expansions policy to provide that the pipeline from Wagga Wagga to Culcairn is part of the Covered Pipeline.

Amendment FDA 40

In order for EAPL's access arrangement for the MSP to be approved, EAPL must remove clause 14.2 from the revised access arrangement.

Amendment FDA 41

In order for EAPL's access arrangement for the MSP to be approved, EAPL must amend clause 4.2 of the revised access arrangement to state that EAPL will submit revisions to the access arrangement together with the applicable access arrangement information (as required under sections 2.28 of the Code) 4 years after the date this access arrangement comes into effect.

EAPL must also amend clause 4.3 to state that the revisions to this access arrangement will commence on the latter of 12 months after the Revisions Submissions Date or the date on which the approval of the revisions takes effect.

Appendix A: Attachment A to the Code

Information disclosure by a service provider to interested parties

Pursuant to section 2.7 the following categories of information must be included in the Access Arrangement Information.

The specific items of information listed under each category are examples of the minimum disclosure requirements applicable to that category but, pursuant to sections 2.8 and 2.9, the Relevant Regulator may:

- allow some of the information disclosed to be categorised or aggregated; and
- not require some of the specific items of information to be disclosed,

if in the Relevant Regulator's opinion it is necessary in order to ensure the disclosure of the information is not unduly harmful to the legitimate business interests of the service provider or a user or Prospective user.

Category 1: Information Regarding Access & Pricing Principles

Tariff determination methodology
Cost allocation approach
Incentive structures

Category 2: Information Regarding Capital Costs

Asset values for each pricing zone, service or category of asset
Information as to asset valuation methodologies - historical cost or asset valuation
Assumptions on economic life of asset for depreciation
Depreciation
Accumulated depreciation
Committed capital works and capital investment
Description of nature and justification for planned capital investment
Rates of return - on equity and on debt
Capital structure - debt/equity split assumed
Equity returns assumed - variables used in derivation
Debt costs assumed - variables used in derivation

Category 3: Information Regarding Operations & Maintenance

Fixed versus variable costs
Cost allocation between zones, services or categories of asset & between regulated/unregulated
Wages & Salaries - by pricing zone, service or category of asset
Cost of services by others including rental equipment
Gas used in operations - unaccounted for gas to be separated from compressor fuel
Materials & supply
Property taxes

Category 4: Information Regarding Overheads & Marketing Costs

Total service provider costs at corporate level
Allocation of costs between regulated/unregulated segments
Allocation of costs between particular zones, services or categories of asset

Category 5: Information Regarding System Capacity & Volume Assumptions

Description of system capabilities
Map of piping system - pipe sizes, distances and maximum delivery capability
Average daily and peak demand at "city gates" defined by volume and pressure
Total annual volume delivered - existing term and expected future volumes
Annual volume across each pricing zone, service or category of asset
System load profile by month in each pricing zone, service or category of asset
Total number of customers in each pricing zone, service or category of asset

Category 6: Information Regarding Key Performance Indicators

Industry KPIs used by the service provider to justify "reasonably incurred" costs
Service provider's KPIs for each pricing zone, service or category of asset

Appendix B: Submissions

The following interested parties provided submissions.

Pre Draft Decision

Boral Energy Holdings Ltd	2 July 1999
Epic Energy South Australia Pty Ltd	2 July 1999
Esso Australia Ltd	2 July 1999
NERA on behalf of Incitec	15 July 1999
Australian Gas Users Group	19 July 1999
Santos	29 July 1999
Incitec Ltd	30 July 1999
Incitec Ltd	18 August 1999
Energy Markets Reform Forum	6 September 1999
Incitec Ltd	24 September 1999
Incitec Ltd	19 October 1999
Santos	23 December1999

Post Draft Decision and revised access arrangement

NSW Ministry of Energy and Utilities	5 February 2001
Transgrid	8 February 2001
Duke Energy Australia Pty Ltd	9 February 2001
Public Interest Advocacy Centre	12 February 2001
Energy Users Association Australia	21 February 2001
AGL Wholesale Gas Limited	28 February 2001
Origin Energy	1 March 2001
ExxonMobil Gas Marketing	10 July 2002
Duke Energy Australia Pty ltd	12 July 2002
Energy Markets Reform Forum	23 July 2002
TXU	29 July 2002
NECG	September 2002
NECG	28 October 2002
NECG	4 November 2002
Duke Energy	2 December 2002
Energy Markets Reform Forum	28 January 2003
AGL Energy Sales and Marketing	13 August 2003
TXU	18 August 2003

Appendix C: Consultants

The following consultants assisted the Commission in relation to this approval process.

The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, July 2002.

McLennan Magasanik Associates Pty Ltd, *Report to Australian Competition and Consumer Commission: Review of forecasts for throughput on the Moomba to Sydney Pipeline*, 6 June 2003

NERA, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios*, October 2000

NERA, *Depreciation within ODRC Valuations*, September 2002

NERA, *The hypothetical new entrant test in the context of assessing the Moomba to Sydney Pipeline Prices*, September 2002

Sinclair, Knight Mertz Pty Ltd, *Depreciation within ODRC valuations,* June 2001 Amended 5 February 2002

Appendix D: Chronology of information provision

Date	From	To	Issue
2001			
14 Mar	EAPL	Commission	EAPL noted its intention to lodge a revised access arrangement to the Commission.
3 Jul	Commission	EAPL	The Commission agreed to a request to postpone the release of the Final Decision, subject to a six month review.
19 Dec	EAPL	Commission	EAPL requested a further postponement of the Final Decision.
2002			
11 Jan	Commission	EAPL	The Commission advised that it intended to proceed with the Final Decision, and requested that the revised access arrangement be submitted by 28 February 2002.
19 Feb	EAPL	Commission	EAPL again requested the deferral of the Commission's Final Decision, or alternatively requested that the revised access arrangement be submitted by 28 June 2002.
8 Mar	Commission	EAPL	Commission reiterated its intention to proceed to Final Decision and requested that EAPL submit its revised access arrangement by 31 March 2002.
11 Mar	EAPL	Commission	EAPL requested that the Commission provide a statement of reasons supporting the Commission's refusal to grant an extension of time.
14 Mar	Commission	EAPL	The Commission agreed to provide this statement, and agreed to wait until the end of April 2002 before calling for further submissions.
1 May	EAPL	Commission	EAPL submitted a revised access arrangement.
3 May	EAPL	Commission	EAPL submitted a summary of key elements of the revised access arrangement.
27 May	Commission	EAPL	The Commission wrote to EAPL setting out additional information requirements.
20 Jun	EAPL	Commission	EAPL provided the Commission with information in response to 27 May 2002 letter.
20 Jun	Commission	Interested parties	The Commission wrote to interested parties outlining the main issues and inviting submissions on the revised access arrangement and additional information.
16 Aug	Commission	EAPL	Request for additional information and clarification.
6 Sep	Commission	EAPL	The commission further requested information sought on 16 August.
9 Sep	EAPL	Commission	EAPL provided further information on several issues including asset valuation and operating costs.
12 Sep	EAPL	Commission	EAPL provided the Commission with a list of outstanding information and indicative dates for submission.
13 Sep	EAPL	Commission	EAPL provided information on opex benchmarks as set out in letter dated 12 September.
20 Sep	Commission	EAPL	EAPL raised a number of preliminary issues relating to the Epic Decision.

Date	From	To	Issue
2002 (continued)			
27 Sep	Commission	EAPL	Commission requested that EAPL provide a public submission specifying errors of law in light of the Epic Decision by 14 October. This letter also requested EAPL's response to four consultancies completed for the ACCC by 29 October 2002.
1 Oct	EAPL	Commission	EAPL provided further information in response to Commission's previous information requests.
9 Oct	EAPL	Commission	EAPL noted that it would make a submission re the Epic Decision, but that the submission would be provided on 29 October rather than 14 October as requested.
15 Oct	Commission	EAPL	The Commission agreed to extend the deadline for EAPL's submission on the Epic Decision to 29 October. The Commission also agreed to extend the deadline for EAPL's response to consultancies to 5 November 2002.
30 Oct	Commission	EAPL	The Commission noted that EAPL had not meet the agreed deadline for its submission re Epic, and advised EAPL that it would provide interested parties the opportunity to respond from 6 November.
1 Nov	EAPL	Commission	EAPL advised that it would submit its response to the Epic Decision by 5 November 2002.
4 Nov	Commission	EAPL	Commission wrote to EAPL regarding the process going forward.
5 Nov	EAPL	Commission	EAPL submitted that following the Epic Decision the MSP Draft Decision contained fundamental errors of law. EAPL submitted further revisions to the value of the ICB based on its 'reasonable expectations under the prior regulatory regime'.
11 Nov	Commission	Interested parties	Commission requested public comments on balancing arrangements and implications of the Epic Decision.
15 Nov	Commission	EAPL	The Commission requested an amalgamated document setting out public information provided by EAPL in response to ongoing requests for information.
18 Nov	Commission	EAPL	Commission sought clarification of issued raised in EAPL's submission regarding the Epic Decision.
21 Dec	EAPL	Commission	Draft consolidated information document submitted by EAPL. EAPL also flagged AGL's new gas supply arrangements.
2003			
30 Jan	EAPL	Commission	EAPL wrote to the Commission advising that there are likely to be a number of impacts on the revised access arrangement from the announcement in December of AGL's new gas supply contracts.
14 Feb	EAPL	Commission	EAPL responded to submissions which were lodged in response to EAPL's comments on the impact of the Epic Decision.
17 Feb	EAPL	Commission	EAPL submitted further information with regard to the calculation of DORC.

Date	From	To	Issue
2003 (continued)			
21 Feb	Commission	EAPL	The Commission requested that EAPL submit revised volume, capital expenditure and non capital expenditure forecasts by 7 March 2003.
7 Mar	EAPL	Commission	EAPL provided tentative volume forecasts.
12 Mar	EAPL	Commission	Final consolidated information document received by the Commission. A public version was submitted on 8 April 2003.
24 Mar	Commission meeting with EAPL		EAPL advised that it intended to undertake a consultancy assessing revised volume forecasts, and that this process would take six weeks to complete.
28 Mar	Commission	EAPL	The Commission requested that EAPL provide details of any delays that may occur in the process and requested additional information on operating and maintenance costs.
15 Apr	EAPL	Commission	EAPL responded to the Commission's request for additional information on operating and maintenance costs.
12 May	EAPL	Commission	ACIL Tasman report and revised volumes submitted by EAPL.
14 May	EAPL	Commission	EAPL suggested that the Commission issue a further Draft Decision or Statement of Intent to allow interested parties to comment on the Commission's position on key aspects of the proposed access arrangement.
16 May	Commission	EAPL	The Commission informed EAPL that it would provide it with 7 days notice between advising it of the process going forward and releasing the decision document.
16 May	EAPL	Commission	EAPL submitted revised operations and capital expenditure forecasts in light of revised volume forecasts.
23 May	EAPL	Commission	EAPL responded to the Commission on the issue of DORC and submitted consultancy reports completed by Venton.
26 May	Commission	EAPL	The Commission wrote to EAPL requesting that a consolidated access arrangement information document be submitted by 10 June 2003.
3 Jun	EAPL	Commission	EAPL agreed to the provision of the access arrangement information, but noted that the deadline could not be met. EAPL advised that additional materials would be supplied by 10 June 2003, and that it would endeavour to have the revised access arrangement information to the Commission by 20 June 2003.
10 Jun	EAPL	Commission	EAPL provided additional materials to the Commission on 10 June 2003, as well as confidential models on 12 June 2003.
12 Jun	Commission	EAPL	The Commission provided EAPL with a copy of the MMA report for comment.
19 Jun	Commission	EAPL	The Commission requested further clarification of the models submitted.
20 Jun	EAPL	Commission	EAPL advised the Commission that it would not be in a position to get the revised access arrangement information to the Commission until 7 July 2003.

Date	From	To	Issue
2003 (continued)			
23 Jun	Commission	EAPL	The Commission wrote to EAPL requesting clarification on the ICB value provided in the models.
25 Jun	Commission	EAPL	The Commission advised EAPL that the information provided did not meet the requirements of sections 2.6 and 2.7 of the Code, and that pursuant to section 2.2 required EAPL to make changes and submit its access arrangement information by 7 July 2003.
26 Jun	EAPL	Commission	EAPL submitted additional information on the calculation of the ICB.
1 Jul	EAPL	Commission	EAPL advised the Commission that it would meet the 7 July deadline for the access arrangement information, but that the additional information requested by the Commission would not be provided until a week later. Finalised confidential models were provided on 8 July 2003.
2 Jul	EAPL	Commission	EAPL provided a response to Commission queries on the confidential model and the calculation of the ICB and noted revised non capital and capital expenditure. .
4 Jul	Commission	EAPL	The Commission agreed to the 14 July 2003 deadline for additional information from EAPL.
7 Jul	EAPL	Commission	Submission of the revised access arrangement information.
9 Jul	EAPL	Commission	EAPL wrote to the Commission noting that it would only be able to submit some of the information by the agreed 14 July deadline, but that a public version of the ACIL Tasman report would not be available until 16 July 2003.
11 Jul	Commission	EAPL	The Commission agreed not to release its own public version of the ACIL Tasman report until 17 July 2003.
14 Jul	EAPL	Commission	In accordance with the deadline agreed on 1 July, EAPL submitted the additional information requested by the Commission.
16 Jul	EAPL	Commission	EAPL submitted a public version of the ACIL Tasman report on volumes.
17 July	Commission	Interested parties	Issues paper released seeking comments on revised volume forecasts submitted by EAPL.
25 Jul	Commission	EAPL	The Commission wrote to EAPL regarding the process going forward.
31 Jul	EAPL	Commission	EAPL wrote to the Commission setting out its methodology for forecast volumes and provided further information with regard to the process going forward.
22 Aug	EAPL	Commission	EAPL provided further details with regard to the volume forecasts proposed.
25 Sep	EAPL	Commission	EAPL wrote to the Commission in response to the Electricity DRP regarding depreciation in moving from ORC to DORC.

Appendix E (Confidential): Non capital costs

The content of this Appendix is confidential.

Appendix F (Confidential): Revenues under the GTD

The content of this Appendix is confidential.

Appendix G (Confidential): Limitations of the incentive mechanism

The content of this Appendix is confidential.

Appendix H: Rolling carryover mechanism

As noted in section 2.11.7 of this report, the Commission is prepared to consider the rolling carryover mechanism should EAPL propose its implementation in its revised access arrangement. The details of this mechanism are outlined in this appendix.

Scope of the rolling carryover mechanism

The Commission is of the view that the rolling carryover mechanism should apply to forecast operating costs but not to capital expenditure forecast by the service provider. It is considered that the rolling carryover is effective with regard to operating expenditure as such expenditure is often ongoing and is influenced by the same cost drivers. Past operating costs are thus a good indicator of future expenditure, subject to any efficiency improvements being achieved.

In contrast, capital expenditure is less predictable and generally consists of lumpy one-off costs. This means that past capital expenditure does not necessarily provide a reasonable indicator of future capital expenditure needs, making the mechanism more susceptible to gaming by the service provider through forecasting higher than expected costs. As argued in the GasNet Final Decision, a simple P_0 mechanism applied to capital expenditure should provide some incentive for efficiency savings while at the same time encouraging some productivity improvements. However, one exception to this rule is SIB capital expenditure. Unlike conventional capital expenditure, SIB capital expenditure is similar in nature to operating costs given that it is generally ongoing and predictable over time.

The following discussion evaluates a number of important elements of the rolling carryover mechanism as it applies to non capital costs. The same broad principles apply to the application of the rolling carryover to SIB capital expenditure. However, given that forecast capital expenditure (including SIB) is rolled into the regulated asset base, any carryover should relate to the return on unanticipated savings (losses) achieved rather than the total savings (losses).

Operation of the rolling carryover mechanism

Under the rolling carryover mechanism, each year's efficiency gain (loss) is calculated by taking the actual reduction (increase) in operating costs anticipated for that year at the start of the previous access arrangement period.[564] This unanticipated efficiency gain (loss) is retained by the service provider for the remainder of the access arrangement period. Further, the regulated tariff is adjusted in the subsequent access arrangement period so that the service provider carries the efficiency gains (losses) for a pre-determined number of years, regardless of when they are achieved.

The table below provides a hypothetical example of the operation of the rolling carryover. In this example there are no efficiencies achieved in year one. In year two the service provider achieved a total of $10 of efficiencies, calculated by subtracting the forecast reduction in costs between year one and year two ($0) from the actual

[564] ESC, *2003 Review of gas access arrangements: consultation paper no.1 – issues for consultation*, May 2001, pp. 96-98.

reduction in costs that occurred between these years ($10). Calculated the same way, the firm achieved an additional $5 of unanticipated efficiency gains between year two and year three, and again between year three and four it achieved $5 of unanticipated efficiency gains. In this example, the regulator determines that the cost forecasts for the second period to be $80 dollars per year.

Under the rolling carryover mechanism proposed by the Commission, unanticipated gains of $10 in year two and $5 in years three and four are kept in the year that they are implemented and for the remainder of that access arrangement period. Revenues in the subsequent period are then adjusted so that calculated efficiency gains (losses) are maintained for a total of five years in addition to the year that they are introduced. In this example, the regulator adds $20 in year six and seven, $10 in year eight and $5 in year nine to the revenues otherwise calculated for those years. This brings the total retention of operating cost efficiencies to six years irrespective of when they are achieved.[565] After that time the allowable revenues for operating costs are reduced to correspond with the forecasts made at the beginning of the subsequent regulatory period.

Example of the rolling carryover mechanism

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Forecast	100	100	100	100	100	80	80	80	80	80
Actuals	100	90	85	80	80					
Year to year efficiency	0	10	5	5	0					
Yr 2 gains kept in the period 1			10	10	10					
Yr 2 adjustments made in period 2						10	10			
Yr 3 gains kept in period 1				5	5					
Yr 3 adjustments made in period 2						5	5	5		
Yr 4 gains kept in period 1					5					
Yr 4 adjustments made in period 2						5	5	5	5	0
Total benefit retained by firm	**0**	**10**	**15**	**20**	**20**	**20**	**20**	**10**	**5**	**0**
Total O&M revenue	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**90**	**85**	**80**

Source: Commission modelling

Benefits of the rolling carryover

As noted earlier, the rolling carryover mechanism overcomes many of the shortcomings associated with a P_0 approach. In particular, since gains (losses) are kept for a pre-determined number of years, irrespective of when they are achieved, there is an

[565] The service provider retains benefits for six years regardless of what part of the year efficiency projects are initially implemented. For example, if a firm has cost forecasts of $100 per year and implements $20 of gains in the fourth quarter of year two, then measured costs in that year would average out to $95. Under the rolling carryover the firm retains this $5 for an additional five years. In year three, assuming no additional productivity improvements have been made, actual costs measured would equal $80, implying an efficiency improvement between years two and three of $15. The firm then carries this $15 for an additional five years. Thus in total the firm carries the $20 achieved for an equivalent of six years - $15 for six years and $5 for six years.

ongoing incentive for the service provider to implement efficiency savings as soon as possible because of the time value of money. This means that there is no incentive for the service provider to defer efficiency gains achievable at the end of the period to the start of the next regulatory period.[566]

In addition, by providing ongoing incentives for least cost operation, it acts as a mechanism for the revelation of the firms underlying costs. Such a characteristic is beneficial for both the service provider and regulator as it reduces the need for detailed assessment of operating costs at the following regulatory review.

Distribution of benefits

Under the rolling carryover mechanism the distribution of benefits (losses) achieved can be determined on an ex ante basis. It is suggested in the literature that there exists a trade-off between the distribution of unanticipated gains to the service provider and efficiency.[567] It is suggested that the productivity of the service provider will be higher when the firm's share of the benefits is greater. This is because the firm is likely to implement efficiency generating projects when the expected payoff to the firm of introducing the projects is higher.

The Commission is not aware of any empirical studies undertaken to assess the optimal distribution of benefits, although theoretical arguments suggest varying benefit sharing proportions. The Commission currently considers that a sharing of approximately 30 per cent to the service provider should provide sufficient incentives to the firm to implement productivity improvements. A sharing of 30 per cent is achieved by allowing the service provider to maintain unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years, as in the example noted above.[568]

Uncontrollable costs

Uncontrollable cost gains (losses) are cost savings (losses) that result from factors outside of the firm's control, such as the weather and general economic conditions. Incentive mechanisms have no impact on uncontrollable factors, thus in theory the firm should not be rewarded or penalised for uncontrollable events. Moreover, allowing the firm to bear the risks associated with exogenous cost factors may increase the cost of capital required to be paid to the firm, which is clearly not desirable.

However, in practice the separation of uncontrollable operating cost gains (losses) from controllable gains (losses) is often difficult. In order to distinguish between these costs,

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566 The rolling carryover represents one of a number of possible mechanisms which provide an ongoing incentive for efficiency savings through the regulatory period. In fact, any incentive regime where the present value of regulated prices over the subsequent regulatory period is proportional to the present value of the observed costs in the previous regulatory period has this characteristic. The rolling carryover, however, also provides information on underlying operating costs, which some other mechanisms do not clearly reveal this aspect (such as a mechanism which sets operating costs in the second period based on the average of past costs).

567 NERA, *Incentives and Commitment in RPI-X regulation*, October 1997.

568 For further details on this approach see ACCC*, Final Decision: GasNet*. Using the real vanilla WACC approved by the Commission of 5.91 per cent as the discount rate, EAPL would retain approximately 35 per cent of efficiency savings under this approach.

the Commission may be required to undertake detailed analysis of company expenditures which would be time consuming for both the regulator and service provider. As discussed earlier, the Commission has approved a pass through mechanism that effectively ring-fences a number of exogenous cost events that may be incurred by the service provider within the access arrangement. Such a pass through mechanism should reduce the risks associated with the inclusion of exogenous events, while at the same time eliminating the need for detailed cost analysis at the review of the access arrangement. Should a pass through event occur and be deemed by the Commission as having an impact on allowed revenues within the access arrangement period, then the amount of the pass through should be excluded from the benefit sharing calculation which is undertaken at the review period.[569]

Equal treatment of gains and losses

An issue that arises from the rolling carryover mechanism is the potential treatment of actuals in one year that exceed forecast (or benchmark) costs. Some industry stakeholders have suggested that regulated utilities should not have to retain losses beyond the year that they are incurred, given that such regulatory behaviour would be unfair.

The Commission contends, however, that it is imperative that both actuals above or below forecasts are taken into account. Detailed modelling suggests that if all expenditures are not incorporated then the incentive properties of the mechanism may be substantially distorted. This opens up the possibility for gaming on the part of the service provider and in turn inefficient outcomes.

Step and trend approach

Given that under the rolling carryover there is an incentive for the service provider to implement efficiency savings as soon as possible means that costs achieved at the end of the regulatory period may be viewed as efficient costs at that time. This information can then be used to determine forecast operating and maintenance costs in the future.

Such an approach, however, is based on the assumption that past costs provide a good indication of future costs, which may not be the case in all situations. There may be circumstances where out-turn costs may not provide a good guide to future costs, such as where: costs are lumpy and variable; costs are cyclical; there are changes in the underlying cost-drivers; the obligations of the regulated company change; or input costs change over time.[570]

One approach that has been implemented for dealing with these ad hoc cost items is the 'step and trend' approach. This mechanism was initially proposed and introduced by the ESC[571] and adopted by the Commission in the GasNet Final Decision.[572] Under this approach, forecasts are adjusted at regulatory reset to incorporate any movements in a range of different cost items, such as the impact of fees or insurance premiums (the

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[569] For further details see ACCC*, Final Decision: GasNet*, p. 282.

[570] NERA, *Efficiency carryover design: A report for SPI PowerNet*, October 2002.

[571] See for example, ESC, *Final Decision: Review of gas access arrangements*, October 2002.

[572] ACCC, *Final Decision: GasNet*.

step). Cost forecasts established through historical data may also be subject to a rate of change factor (the trend) through the access arrangement period. This trend factor would reflect assumptions such as total factor productivity in the industry, costs of inputs and the impact of demand growth.[573]

While the practical implementation of the step and trend approach currently represents an area of further research, the Commission considers that it would be appropriate to introduce such a framework in the initial access arrangement for the MSP in order to promote regulatory certainty and transparency.[574]

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573 ACCC, *Final Decision: GasNet*.

574 A recent paper by NERA (*Efficiency carryover design: A report for SPI PowerNet*, October 2002) provides some background and guidance on the exercise of discretion when setting expenditure benchmarks. Specifically, NERA suggested that the following two principles need to be adhered. First, when setting future benchmarks, costs that have been allowed for in past benchmarks but not actually incurred should not be included. This is because the inclusion of such costs would constitute double-counting. Second, when establishing an efficiency trend factor it is imperative that this factor is based on forecasts of the impact of factors beyond the businesses control – such as changes in input costs or the ageing of assets. Past efficiencies achieved by the firm should not be used as this may unravel the efficiency mechanism in place.