Final Decision

GasNet Australia
access arrangement revisions
for the Principal Transmission System

13 November 2002

File No:	**Commissioners:**	
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Preface

GasNet Australia (Operations) Pty Ltd (GasNet) lodged proposed revisions to its natural gas transmission access arrangements with the Australian Competition and Consumer Commission (the Commission) on 28 March 2002. The Victorian Energy Networks Corporation (VENCorp) also lodged proposed revisions to its access arrangement at that time. The Commission approved these access arrangements in 1998.

This Final Decision sets out the Commission's assessment of GasNet's proposed revised access arrangement in accordance with the provisions of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code). The Commission has released a separate Final Decision with respect to VENCorp's proposed revised access arrangement.

Under the terms of the Code the Commission is required to decide whether to approve or not approve the proposed revisions. It may only approve GasNet's proposed revised access arrangement 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. In doing so the Commission must take into account the factors described in section 2.24 of the Code and the provisions of the access arrangement.

On 14 August 2002 the Commission made its Draft Decision and proposed not to approve GasNet's proposed revised access arrangement in its current form. The Commission set out the amendments (or nature of the amendments) which would have to be made to the revisions for it to approve them.

GasNet did not submit amended revisions in response to the Draft Decision. After considering submissions from interested parties the Commission has decided to confirm the Draft Decision. This Final Decision sets out the amendments (or nature of the amendments) which are required in order for the Commission to approve GasNet's revisions.

GasNet must submit amended revisions that comply with this Final Decision by 2 December 2002 in order for the Commission to approve the revisions. If it does not, the Commission must draft and approve its own revised access arrangement.

Copies of GasNet's proposals and related information are available from the Commission's website at www.accc.gov.au (under 'Gas').

Contents

Abbreviations and glossary

1998 Final Decision	ACCC, *Final Decision: access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; and access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, 6 October 1998
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) until the next revisions commencement date
ACG	The Allen Consulting Group
AGA	Australian Gas Association
AGSM	Australian Graduate School of Management
AMDQ	authorised maximum daily quantity
APT	Australian Pipeline Trust
ATT	average transmission tariff
CAPM	capital asset pricing model
Code	National Third Party Access Code for Natural Gas Pipeline Systems
Commission	Australian Competition and Consumer Commission
covered pipeline	a pipeline to which the provisions of the Code apply
CPI	Consumer Price Index
DEI	Duke Energy International
DNRE	Department of Natural Resources and Environment,

	Victoria
DRP	*Draft Statement of Principles for the Regulation of Transmission Revenues*
EAPL	East Australian Pipeline Ltd
EGP	Eastern Gas Pipeline
Epic decision	*Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231*
ESC	Essential Services Commission
EUAA	Energy Users Association of Australia
EUCV	Energy Users Coalition of Victoria
FATT	Forecast average transmission tariff
G&A	general and administrative
GasNet	GasNet Australia (Operations) Pty Limited
GHD	Gutteridge, Haskins and Davey Pty Limited
GIA	Gas Industry Act
GJ	Gigajoule (one thousand million joules)
GNS	GasNet System
GPAL	Gas Pipelines Access Law
GST	Goods and Services Tax
ICB	initial capital base
IPO	initial public offer
IRR	internal rate of return
km	Kilometre
KPI	Key performance indicators
LNG	Liquefied Natural Gas
market carriage	a capacity management system where the service provider does not normally require users to commit to a contract. Instead charges are based on actual usage

MATT	Maximum average transmission tariff
MDQ	Maximum daily quantity
MIC	Mercer Investment Consulting
MSOR	Market and System Operations Rules
MSP	Moomba to Sydney Pipeline
NECG	Network Economics Consulting Group
NGPAC	National Gas Pipelines Advisory Committee
NPV	net present value
O&M	Operating and maintenance
ORC	Optimised replacement cost
ORG	Office of the Regulator-General, Victoria
PJ	Petajoule (one thousand terajoules)
PPT	the weighted average X factor for all tariffs
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)
PTS	Principal Transmission System
RAB	Regulatory asset base
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
SEA Gas pipeline	a proposed pipeline between Port Campbell and Adelaide to be built by South East Australia Gas (SEA Gas) Pty Ltd

service envelope agreement (SEA)	an agreement between VENCorp and GasNet whereby GasNet makes the Gas Transmission System available to VENCorp
service provider	a person who is the owner or operator of the whole or any part of the pipeline or proposed pipeline
Tariff Order	Victorian Gas Industry Tariff Order
TJ	Terajoule (one thousand gigajoules)
TPA	Transmission Pipelines Australia Pty Ltd
UGS	Underground Gas Storage
VENCorp	Victorian Energy Networks Corporation
Victorian Code	Victorian Third Party Access Code for Natural Gas Pipeline Systems
WACC	Weighted average cost of capital
WTS	Western Transmission System

Executive summary

The Australian Competition and Consumer Commission (the Commission) is currently conducting its first scheduled review of the GasNet Australia (Operations) Pty Ltd (GasNet) and the Victorian Energy Networks Corporation (VENCorp) access arrangements which it approved in 1998. GasNet owns the Victorian Principal Transmission System (PTS) and Western Transmission System (WTS) while VENCorp is the independent system operator of the PTS.

The two service providers submitted proposed revised access arrangements and access arrangement information to the Commission on 28 March 2002. While the revisions are subject to two separate regulatory processes (see also the VENCorp Final Decision) this document also refers in part to the proposed VENCorp revisions where applicable.

GasNet has proposed substantial changes to its access arrangements whereas VENCorp's proposal is largely to maintain the status quo. GasNet proposed significant real increases in tariffs and revenues while VENCorp proposed decreases.

The Commission has decided to accept a range of major changes to the arrangements it approved in 1998. These include merging GasNet's two access arrangements, including the Southwest Pipeline and the Murray Valley pipeline in the asset base, the introduction of pass through mechanisms and prudent discounts, changes to the tariff control formula and the removal of the automatic requirement for small pipeline extensions to be regulated. The Commission accepts GasNet's aggregate demand forecasts and that it recoup approximately $12.9 million of unrecovered revenue from the first access arrangement period. It also considers that GasNet should be able to retain approximately $16 million of tax allowances included in GasNet's target revenue for the first access arrangement period under the pre-tax approach adopted for that time. However, it does not consider that a number of other proposals are consistent with the principles and objectives of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code).

After considering GasNet's proposals and submissions by interested parties, the Commission decided on 14 August 2002, pursuant to section 2.35(b) of the Code, to issue a draft decision proposing not to approve the proposed revisions to GasNet's access arrangements in their current form. The Draft Decision set out the amendments (or nature of the amendments) which would have to be made to the revisions for the Commission to approve them.

GasNet did not submit amended revisions in response to the Draft Decision. After considering submissions from GasNet and other interested parties the Commission has decided to confirm the Draft Decision. Accordingly, it has decided, under section 2.38(a)(ii) of the Code, not to approve the revisions proposed by GasNet. This Final Decision sets out the amendments (or nature of the amendments) which are required in order for the Commission to approve GasNet's revisions. These vary in some instances from those proposed in the Draft Decision, mainly as a result of consideration by the Commission of submissions by GasNet and other interested parties.

GasNet must submit amended revisions that comply, to the Commission's satisfaction, with this Final Decision by 2 December 2002 in order for the Commission to approve the revisions. If it does not, the Commission must draft and approve its own revised access arrangement. Key issues are summarised below.

Key issues

Rolling forward the capital base

The Commission carefully considered the merits of GasNet's proposal to reopen its regulatory asset base and to adjust it upwards by $41.2 million (to a January 1998 value of $399.2 million). The Commission considers that such a revaluation is unwarranted and would not be consistent with regulatory policy objectives. In particular, the consequent increases in transmission charges would be inconsistent with the interests of users, prospective users, end-users and prospective end-users. The Commission is satisfied that it correctly interpreted the requirements of the (Victorian) Code when it approved GasNet's predecessor's proposed valuation of the initial capital base in 1998. The valuation approved in 1998 ($358.0 million) was consistent with that proposed by the Victorian Government as owner at the time of the PTS and WTS. The subsequent purchases of these assets were made in the knowledge that the regulatory asset base had already been set. Thus there is no conflict with GasNet's legitimate business interests.

In addition, the Code does not give the Commission the discretion to make such an adjustment once the initial capital base has been established. Accordingly, the Commission does not accept the revaluation proposed by GasNet to the initial capital base.

The roll forward of this capital base to the start of the next access arrangement period involves the addition of the Southwest Pipeline, the Interconnect Assets, the Western Transmission System, the Murray Valley Pipeline and some smaller investments, deduction of depreciation and redundant assets and inflation adjustments to the capital value each year. The Commission considers that the appropriate value of the regulatory asset base at 31 December 2002 will be approximately $494.2 million.

Benchmark rate of return

GasNet proposed a benchmark return on equity of 14.19 per cent. The Commission has generally accepted the parameter values proposed by GasNet as input to the benchmark return calculation under the capital asset pricing model (CAPM) methodology. However, it considers the proposed equity beta exaggerates the risks faced by a regulated natural gas transmission service provider and that a value of 1.0 (the market average) would be more appropriate for GasNet. Importantly, the Commission has accepted a number of changes proposed by GasNet that will reduce its risks for the second access arrangement period. In addition, it considers that the most appropriate bond rate term for calculating the risk free rate is one that corresponds to the regulatory period. The Commission considers that a benchmark return on equity of 11.15 per cent is appropriate for GasNet. The reduction in the benchmark since the Draft Decision reflects changes in prevailing financial market conditions that indicate a fall in the risk free rate.

Importantly, incentives proposed for the second access arrangement period would allow GasNet the opportunity to exceed this benchmark return.

Revenue approach

GasNet initially proposed to use what is in effect a pre-tax approach to determine target revenue and to retain the benefits of tax pre-paid by users during the first access arrangement period. It also proposed that the benefits of accelerated depreciation would accrue to GasNet rather than flow through to lower charges. The Commission has adopted a post-tax approach that treats tax as a cost component in the cash flows. It does not consider that the benefits of accelerated depreciation should accrue to GasNet as this would not be consistent with the outcome expected in a competitive market. However, it accepts that GasNet be able to retain the benefits of tax pre-paid by users during the first access arrangement period. This is a substantial benefit to GasNet worth approximately $16 million.

The Commission has agreed to GasNet adopting a tariff normalisation approach in order to reduce tariff shock in the future when benchmark tax payments commence. This approach brings some of GasNet's future gross revenues forward. Accordingly, benchmark revenue for the second access arrangement period will be higher than it would otherwise be. Later revenue will be commensurately decreased, but revenue over time will remain unchanged in net present value (NPV) terms.

Tariff path

GasNet proposed a real increase in weighted average tariffs from the 2002 tariffs to the discounted weighted average tariff to apply over 2003 to 2007 of 11 per cent. Revenue was proposed to increase by approximately 38 per cent between 2002 and 2003. The average tariff would also increase sharply between 2002 and 2003 then follow a (weighted average) consumer price index (CPI)-4.5 per cent price path. Following the reduced revenue requirement set out by the Commission in this Final Decision, a different tariff path is required. The tariff path required by the Commission takes into consideration the initial change in tariffs between 2002 and 2003, the price path within the period, and the end of period tariff movement. This tariff path can be described by an initial change of ten per cent followed by a CPI-3 per cent price path over the remaining period. The impact of the initial change is overstated as unregulated revenues currently received by GasNet for use of the Southwest Pipeline are not included in the calculation.

Costs allocation and tariff structure

For the first access arrangement period, GasNet allocated capital costs to pipeline and compressor assets groups on the basis of their Optimised Replacement Cost (ORC) and then to users within the asset groups on the basis of peak usage. This constituted 65 per cent of costs. Direct operating costs were allocated to withdrawal assets on the basis of distance from the gas source and the total volume withdrawn. Indirect costs were allocated on a postage stamp basis (an amount per GJ, irrespective of the amount of the system used). A peak injection and a peak withdrawal tariff was charged (recovering 65 per cent of revenue requirement) and an anytime tariff was charged on total volumes.

GasNet's proposed cost allocation is broadly similar with the following changes: direct operating costs are allocated to injection as well as withdrawal pipelines; and the allocation of 60 per cent (rather than 65 per cent) of costs on the basis of peak usage. As well, there are new costs proposed to be allocated on a postage stamp basis: under-recovered K factor adjustment; GasNet's share of efficiency gains; and capital raising costs.

With regard to tariffs, GasNet proposed to remove the peak withdrawal tariff, leaving the peak injection tariff which will recover 27 per cent of the revenue requirement and the anytime withdrawal tariff which will recover 73 per cent of the revenue requirement. As well, a new cross system withdrawal tariff is proposed (which is likely to affect a very small number of customers).

The Commission considers the appropriate basis for allocating the unrecovered K factor amount to be by increasing all tariffs by the same proportion; and capital raising costs on the same basis as capital costs. The Commission considers that the allocation proposed by GasNet of all other costs is appropriate.

The major issue raised in terms of economic principles by the change to cost allocation and tariff structure is that of appropriate price signals. In addition, retailers have expressed concern that the retention of peak day injection tariffs would perpetuate the difficulties they currently experience with the annual 'wash-up'. Further, a number of parties expressed concern that the changes would reduce the cost-reflectivity of tariffs.

Some interested parties call for the removal of all peak pricing and others call for the retention of the current structure. Peak signals are appropriate if the relevant asset is constrained or likely to be constrained, and if users are likely to respond to such signals. The evidence suggests that the withdrawal pipelines are generally not close to constraint and that users generally do not respond to peak signals. On the other hand, the possibility of the injection pipelines becoming constrained in the short to medium term is higher. Consequently, the Commission is not convinced that the economic evidence is compelling for any of the alternatives proposed by interested parties in their submissions.

GasNet's proposal represents a 'flatter' tariff structure than that currently in place in that it would result in peaky loads being charged comparatively less. The proposals put forward by retailers would result in a further flattening and shift in costs to high load factor customers. While the Commission appreciates the difficulties experienced by retailers in conducting the wash-up, it is not persuaded that it is reasonable to further flatten tariffs at this stage. The Commission has decided to accept GasNet's proposed methodology for cost allocation and tariff structure.

Southwest Pipeline

The Commission has confirmed the proposal in the Draft Decision to accept inclusion of GasNet's investment in the Southwest Pipeline in the capital base. This will be partly under the Code's economic feasibility test ($42.5 million) and partly under the system-wide benefits test ($42.5 million). This approach was not available under the provisions of the PTS access arrangement as they applied in 2001 when the Commission considered an application by GasNet's predecessor to roll-in the full cost of the Southwest Pipeline under the system-wide benefits test. To preserve the intent of the economic feasibility test, that part of the Southwest Pipeline investment incorporated in the asset base under the economic feasibility test will be quarantined from the K factor mechanism.

Murray Valley Pipeline

The Commission has decided to include GasNet's investment in the Murray Valley Pipeline in the capital base as it is satisfied that it passes the Code's economic feasibility test.

Quarantining of costs

After careful consideration, the Commission has accepted arguments that it should isolate costs associated with inclusions to the capital base (under the economic feasibility test) so that they are not borne by parties who do not use the facility. Thus the Murray Valley pipeline and the portion of the Southwest Pipeline which passed the economic feasibility test will be isolated from the standard cost allocation model and the tariffs will be constructed on a cost recovery basis for each of those assets. The tariffs for these assets will also be removed from the K factor calculations. If this were not done then the K factor mechanism would allow GasNet to charge any under-recovery on these new assets to the users of existing facilities thus undermining the stand-alone basis on which they were included in the regulatory asset base (RAB) under the economic feasibility test.

Merger of the Western Transmission System access arrangement

The Commission has accepted GasNet's proposal that the revised access arrangement will be in respect of both the PTS and the WTS. While the WTS is not in the K factor currently, its tariff calculation is largely integrated with the PTS and the revision proposes to fully integrate it. This proposal has been accepted. Isolation from the K factor calculations would be inconsistent with this approach.

Services policy

GasNet contended that VENCorp, but not GasNet, provides reference services. The Commission has concluded that GasNet's access arrangement must contain a services policy which includes appropriate reference services and is consistent with VENCorp's access arrangement.

Terms and conditions

As the Commission concluded that GasNet's access arrangement must provide reference services, it must contain appropriate terms and conditions on which it will provide the reference services.

Pass through mechanism and zonal changes

GasNet proposed a 'pass through' mechanism (for tax increases, increased regulatory requirements and increased insurance premiums) and a mechanism allowing it to change zones. These mechanisms would not require assessment under the Code's standard review process. While such a mechanism would represent a departure from the Commission's preferred pure incentives based approach, it is aware that the Code gives the service provider discretion in this area. The Commission acknowledges that the proposed mechanisms are likely to be cost-effective and agrees to them in principle. However, it requires changes to the proposals made by GasNet to allow sufficient evaluation time for due process, so that decreased costs can also be passed through and to establish an annual pass through mechanism.

Benefit sharing mechanism

GasNet proposed no benefit sharing carryover for efficiencies achieved for capital expenditure. For operations and maintenance expenditure, GasNet proposed a benefit sharing mechanism which defined operational efficiencies achieved by GasNet in terms of the difference between forecast costs for the last year of the period and forecast costs for the subsequent period.

The Commission concurs with the proposal put forward by GasNet for capital expenditure. With regard to operations and maintenance expenditure, the Commission did not agree with GasNet's proposal for the first period as it considers that a benefit sharing mechanism should take into account temporary efficiencies that are actually achieved. GasNet achieved considerable reductions in its operations and maintenance costs during the initial access arrangement period and has enjoyed the benefits of these savings. However, these efficiencies have not been sustained. Under the Commission's preferred efficiency approach, this performance would result in a negative efficiency carryover for GasNet into the second access arrangement period. However, GasNet was not aware of this particular benefit sharing mechanism prior to or during the first access arrangement period. On balance, the Commission does not require any revenue reduction to operations and maintenance expenditure as a consequence of the benefit sharing mechanism in the second access arrangement period.

The Commission also did not agree with GasNet's initial proposal for the treatment of operations and maintenance expenditure efficiencies in the second period. Instead the Commission decided in the Draft Decision to adopt the rolling carryover mechanism for unanticipated gains (losses) realised in the second and subsequent periods. In response to the Draft Decision, GasNet agreed in principle with the mechanism put forward by the Commission, but proposed that certain costs, including pass through costs, should be excluded from the model. After further consideration, the Commission has decided to exclude events that qualify for pass through from the mechanism, but has decided to maintain all other operating costs within the scope of the model.

Prudent discounts

The Commission has assessed GasNet's proposal to introduce prudent discounts for the La Trobe, Wodonga, Western zones and Dandenong Bypass. It has decided that GasNet's proposals are reasonable.

Forecast capital expenditure

GasNet has forecast capital expenditure of $87 million over the second access arrangement period. The Commission considers that the proposed investments in the majority of projects are reasonably likely to pass the requirements in section 8.16 of the

Code when those investments are forecast to occur. However, the Commission does not consider it appropriate to include the forecast expenditure for a number of projects at this time. These include:

- the Brooklyn loop project – it is uncertain as to whether this project will proceed within the forthcoming access arrangement period;
- Lurgi rehabilitation project – the Commission accepts the costs associated with the first stage of this project but does not accept the proposed stage two costs due to their considerable uncertainty; and
- possible service lines – there is no information available to assess the proposed investments against Code criteria and it is uncertain whether these service lines would be covered by GasNet's access arrangement in the event that they are built.

A total of $47.3 million of forecast new facilities investment has been included in the determination of the reference tariffs for the second access arrangement period. The balance of the forecast expenditure can be included in the capital base if it is undertaken and the facility is covered by GasNet's access arrangement (subject to the tests in section 8.16 of the Code).

Forecast operations and maintenance expenditure

The Commission has assessed GasNet's forecast expenditure on operations and maintenance. It does not accept a number of GasNet's proposals for inclusion of costs in the calculation of benchmark revenues. These include:

- allowance for asymmetric costs – the majority of the proposed allowance has not been accepted by the Commission as many items included in the allowance were not considered appropriate either in quantum or in the impact on users and GasNet;
- litigation costs associated with the 1998 Longford incident; and
- parts of GasNet's claimed regulatory review costs which the Commission considers are not prudent or are not sufficiently related to the review.

Working capital

In the Draft Decision a return on working capital was rejected. The Commission understands that what GasNet has referred to as 'working capital' (linepack and spare parts) differs from the normal meaning of the term (debtors less creditors). The Commission has rejected claims for a return on the latter item in the past. A return on linepack and spare parts is appropriate but GasNet has over-estimated their value. The Final Decision accepts the validity of the claim but amends its calculation.

Forecast demand

The Commission has considered the (comparatively small) differences between the aggregate gas demand projections underpinning the proposed GasNet and VENCorp tariffs. It considers that these forecasts should be consistent across the two access arrangements. It notes that the VENCorp forecasts have been determined through a transparent process involving public consultation and that they form a sound basis for deriving tariffs for the second access arrangement period. The Commission considers that adjustments incorporated by GasNet to further accommodate a projected warming trend may, on balance, be reasonable.

The Commission has decided to accept GasNet's aggregate forecasts as proposed in March 2002 for the purposes of both access arrangements. However, some changes are required to GasNet's projected flow estimates to reflect the development of the Yolla fields. GasNet proposed, following the Draft Decision, that a further adjustment be included in its forecasts in recognition of a warming trend affecting ten day peak demand. Details of this proposal have not been made available. The Commission considers that it would be appropriate to consider evidence of this proposal in the context of a future review of GasNet's access arrangement.

Capital redundancy policy

The current policy allows an adjustment to be made to GasNet's capital base for partially or wholly redundant assets at the time of a scheduled review of the access arrangement. GasNet considers that the provision regarding partially redundant assets creates uncertainty and should be removed. While the Commission acknowledges that some uncertainty may exist, it is not persuaded that it should be shifted so that it falls on users. The Commission also notes that the existence of a capital redundancy policy encourages a service provider to ensure that its investments are appropriate . The Commission requires GasNet to retain its current redundant capital policy.

Asset lives

The Commission acknowledges concerns expressed by interested parties about GasNet's proposals to change the effective end of life estimate of the Longford to Pakenham pipeline from 2030 to 2023 and to adopt an effective life for the Southwest Pipeline extending until 2052. In its Draft Decision the Commission stated that a reduction in the expected life of the Longford to Pakenham pipeline was not warranted but that GasNet's proposed life for the Southwest Pipeline was reasonable. After further consideration of demand and reserve depletion projections, the Commission has decided to accept all the end of effective life estimates proposed by GasNet.

Part A – Introduction

1. Introduction

1.1 Access arrangement revisions

GasNet Australia (Operations) Pty Ltd (GasNet) is currently subject to two separate natural gas transmission access arrangements, which were approved by the Australian Competition and Consumer Commission (the Commission) in 1998, for the Principal Transmission System (PTS) and the Western Transmission System (WTS).

In accordance with the provisions of its access arrangements, GasNet submitted a proposed revised access arrangement and revised access arrangement information to the Commission on 28 March 2002. GasNet states that its single revised access arrangement would apply to the GasNet System (GNS) which would include both the PTS and the WTS.[1]

Under the market carriage capacity management system operating on the PTS, users pay tariffs to both the system owner, GasNet, and the independent system operator, Victorian Energy Networks Corporation (VENCorp). Approximately 85 per cent of the combined tariff is currently paid to GasNet. VENCorp has also submitted a proposed revised access arrangement to the Commission which is the subject of a separate Final Decision.

An access arrangement describes the terms and conditions on which a service provider will make access available to third parties. The initial access arrangement period ends on 31 December 2002. The second access arrangement period is scheduled to commence on 1 January 2003 and is proposed to end on 31 December 2007. However, service providers have the discretion to submit revisions earlier than at a scheduled review.

Under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code), the Commission is required to:

- inform interested parties that it has received the proposed revisions to the access arrangements and the associated access arrangement information (parties were notified by letter on 5 April 2002);
- publish a notice in a national daily newspaper which at least: describes the covered pipelines to which the access arrangements relate; states how copies of the documents may be obtained; and requests submissions by a date specified in the notice (the notice was inserted in the *Australian Financial Review* and the *Age* on 8 April 2002);
- after considering submissions received, issue a draft decision which either proposes to approve the revisions or proposes not to approve the revisions and states the amendments (or nature of the amendments) which would have to be made to the

1 In contrast, VENCorp refers to the combined system as the PTS. For consistency, the convention has been adopted in this Final Decision of referring to the system as the PTS.

revisions in order for the Commission to approve them (the Draft Decision was released on 20 August 2002);

- after considering additional submissions, issue a final decision that either approves or does not approve the revisions (or amended revisions) and states the amendments (or nature of the amendments) which have to be made to the revisions (or amended revisions) in order for the Commission to approve them (the Final Decision is to not approve the revisions); and
- if the amendments are satisfactorily incorporated in amended revisions, issue a final approval. If the Commission is satisfied that the amended revisions either substantially incorporate the amendments specified or otherwise address to its satisfaction the matters which led to it specifying the amendments in its final decision, either approve or not approve the amended revisions. In any other case, the Commission must draft and approve its own revisions.

1.2 Criteria for assessing revisions to access arrangements

The Commission may approve revisions to an access arrangement only if it is satisfied that the access arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Code. These are summarised below. Revisions to an access arrangement cannot be opposed solely on the basis that the access arrangement as revised would 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 revisions to an access arrangement.

An access arrangement, or a revised access arrangement, must include the following elements:

- a policy on the service or services to be offered which includes a description of the service(s) to be offered;
- a reference tariff policy and 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;
- 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 an extension or expansion 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.

The Code (section 10.2) provides that, where there is more than one service provider in connection with a covered pipeline, with one the owner and the other the operator, responsibility for complying with the obligations imposed by the Code is allocated among them by their access arrangement(s) and each service provider is responsible for complying with the responsibilities allocated to it.

In assessing proposed revisions to an access arrangement, the Commission must take into account the provisions of the access arrangement as it currently stands (section 2.46) and, pursuant to section 2.24 of the Code, the following factors:

(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;[2]

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

On 23 August 2002 the Full Court of the Supreme Court of Western Australia handed down its decision in the matter of: *Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231* (the Epic decision). This decision is the most authoritative assessment available of 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.

The Epic decision largely focused on the appropriate approach to adopt when setting the initial capital base for a pipeline. GasNet's initial capital base was set by the Commission in 1998 and is not directly subject to the current review. Nonetheless, the decision provides valuable guidance in interpretation that is directly relevant to the current review. In particular, the Court found that the factors in section 2.24 of the Code are relevant to the whole of an access arrangement, including reference tariffs and the reference tariff policy. In determining reference tariffs and the reference tariff policy, the regulator should apply the objectives in section 8.1, but should be guided by section 2.24 where these objectives conflict or give the regulator discretion. A regulator must give weight to each of the factors specified in section 2.24 as fundamental elements.

A number of parties have referred to the Epic decision in their responses to the Draft Decision. For example, the Australian Gas Association (AGA) provided a summary of its interpretation of the judgement. While it noted that the decision is not a legal precedent that the Commission is bound to apply, it commented that it is the only

[2] 'User' means a person who has a current contract for a service or an entitlement to a service as a result of an arbitration (section 10.8 of the Code).

judicial interpretation of core provisions of the Code.[3] The AGA states that the Commission may have erred in a number of aspects of the Draft Decision, such as by giving undue weight to economic efficiency, failing to have regard to section 2.24 in reconciling conflicting principles in section 8.1 and by interpreting section 8.1(a) as an 'overarching requirement'.[4]

BHP Billiton noted the requirements under section 2.24(f) for the regulator to take into account the interests of users and prospective users and under section 3.2(b) for users and prospective users to be able, to the extent practicable and reasonable, to obtain a service which only includes wanted elements.[5] BHP Billiton suggested that, together, these provisions meant that 'users and prospective users must be able to replicate their tariffs to establish that they are fair, reasonable, efficient and cost reflective'.[6] The Commission's consideration of the services policy (section 3.2) and access arrangement information provisions are discussed in sections 11.1 and 9 of this Final Decision respectively.

More generally, the submissions that refer to the Epic judgement are addressed in the relevant sections of the Final Decision.

Appendix A to this Final Decision sets out the access arrangement information that a service provider must disclose to interested parties (Attachment A to the Code).

1.3 Consultative process

In accordance with the requirements of the Code, the Commission informed interested parties of the review process once revisions were lodged. It published a notice requesting submissions, and, after considering submissions, issued a Draft Decision on 14 August 2002. At that time it requested that further submissions be lodged no later than 13 September 2002. A number of interested parties requested additional time to comment on further information provided in the Draft Decision and by GasNet in its 20 September response to the Draft Decision. A listing of submissions received is included at Appendix B. The Commission has now, after considering these submissions, issued its Final Decision.

In addition, the Commission released an Issues Paper to assist the preparation of submissions and advertised the release of the Draft Decision in the *Australian Financial Review*. Further, a number of parties requested that the Commission hold a public forum before reaching its final decision.[7] While these parties saw benefit in this proposal, the Commission noted the tightness of timing leading up to the proposed implementation of revised tariffs on 1 January 2003 and the importance that GasNet and users place on certainty about the timing of implementation of revised tariffs. On balance, the Commission decided not to hold a public forum in this instance.

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3 AGA submission, 13 September 2002, p. 5.

4 ibid., pp. 6-7.

5 BHP Billiton submission, 13 September 2002, p. 4.

6 ibid.

7 BHP Billiton, EUCV and Amcor and PaperlinX.

Copies of the revisions applications and associated documents are available (subject to confidentiality restrictions) from the Commission’s website (www.accc.gov.au) and placed on the public registers held by the Commission and the Code Registrar. Copies of this Final Decision may also be obtained from the Commission by contacting Ms Hema Berry on telephone (02) 6243 1233, fax (02) 6243 1205 or e-mail: hema.berry@accc.gov.au. Copies of the revisions applications on computer disk can also be obtained from Ms Berry.

2. Background

The PTS and the WTS were both owned by the Victorian Government entities Transmission Pipelines Australia Pty Ltd (TPA) and Transmission Pipelines Australia (Assets) Pty Ltd at the time the Commission approved the PTS and the WTS natural gas transmission access arrangements in 1998. Ownership of these pipelines passed to GPU GasNet Pty Ltd in 1999 and then to GasNet in 2001. VENCorp remains the independent system operator of the PTS.

The Victorian Government enacted the Gas Pipelines Access (Victoria) Law, effective 1 July 1997, which brought the Code into force in Victoria (though certain provisions of the *Victorian Third Party Access Code for Natural Gas Pipeline Systems* (the Victorian Code) were grandfathered until the first scheduled review).

2.1 Victorian gas industry structure and regulatory framework

Relevant aspects of the Victorian gas industry structure include:

- GasNet owns the PTS in Victoria which until recently solely transported gas supplied from the Esso-BHP Billiton fields in the Gippsland Basin. VENCorp is the independent system operator for the PTS. The subsequent completion of the Interconnect Pipeline and the Southwest Pipeline also allows Cooper Basin and Otway Basin gas to be supplied via the PTS;
- GasNet also owns the WTS which until recently solely transported gas supplied from the on shore Otway Basin gas fields to the western parts of Victoria. Since completion of the Southwest Pipeline, Gippsland Basin gas has been supplied via the WTS. The TXU owned Underground Gas Storage (UGS)[8] facility provides a source of peak gas flows via the Southwest Pipeline. GasNet proposes that the WTS and the Southwest Pipeline be included from the start of the second access arrangement period in a single access arrangement for the PTS;
- since July 1998 the Interconnect Pipeline has linked the PTS with the Moomba to Sydney Pipeline (MSP). The MSP is owned and operated by East Australian Pipeline Ltd (EAPL), an entity owned by the publicly listed Australian Pipeline Trust (APT). The section of the Interconnect Pipeline from Barnawartha to Culcairn forms part of the PTS and is owned by GasNet and operated by VENCorp. EAPL owns and operates the remainder of the Interconnect Pipeline from Culcairn to Wagga Wagga. The pipeline allows southward flows of gas supplied by the Cooper Basin producers to Victoria and for northward flows of Gippsland Basin gas to NSW;
- Duke Energy International (DEI) owns and operates the Eastern Gas Pipeline (EGP) which commenced operations supplying Gippsland Basin gas to customers in NSW in 2000. It also owns the Tasmanian Gas Pipeline which commenced delivering Gippsland Basin gas to Tasmania in 2002; and

8 Previously known as Western Underground Gas Storage (WUGS).

- a number of new gas sources, located primarily in the Otway Basin, are expected to commence supply to the GasNet system and to South Australian customers in the short to medium term.

The main legislation and relevant documents regulating access to the Victorian gas transmission industry are:

- the Code, under which transmission service providers are required to submit access arrangements and revised access arrangements to the Commission for approval;
- the *Gas Pipelines Access (South Australia) Act 1997*; and
- the *Gas Pipelines Access (Victoria) Act 1998*.

In addition, certain provisions of the Victorian Code under which the Commission approved the PTS access arrangement in December 1998 have been grandfathered. Sub-section 24A(3) of the *Gas Industry Acts (Amendment) Act 1998* provides that access arrangements approved under the Victorian Code (such as the access arrangements for the PTS and WTS) continue to be subject to sections 3 and 8, (and section 9 so far as it applies to sections 3 and 8) and to sections 2.33 and 2.48A of the Victorian Code. These sections are not subject to the corresponding provisions of the Code until the first scheduled review of the access arrangements under section 2 of the Code.

The Code and appeals bodies in Victoria 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.

Parts of a number of regulatory instruments are currently included in the access arrangements. This reflects the institutional arrangements imposed by the Victorian Government in 1998 and 1999 when it reformed and privatised its integrated gas supply business. Further, as noted earlier, while GasNet owns the PTS and the WTS, the Victorian Government gave VENCorp the role of independent system operator for the PTS. Under the terms of the Code, both GasNet and VENCorp are service providers. Their access arrangements allocate responsibility between them for complying with the obligations imposed by the Code.

2.2 The initial access arrangement assessment

On 16 December 1998, the Commission approved the following Victorian gas transmission access arrangements under provisions of the Victorian Code with initial access arrangement periods ending on 31 December 2002:

- access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the PTS;

- access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the WTS;
- access arrangement by VENCorp for the PTS.

2.3 Broad issues

2.3.1 Merging of the GasNet access arrangements

GasNet proposes to merge the PTS access arrangement and the WTS access arrangement into a single GasNet access arrangement with effect from 1 January 2003. At the time the access arrangements were approved in 1998 the two systems were physically separate. Following the completion of the Southwest Pipeline in 1999, they are now physically interconnected. As part of the merger, the capacity management system for the WTS would change from contract carriage to the market carriage system applicable on the PTS.

GasNet identifies advantages in merging the PTS and WTS access arrangements, in particular, that a merger would:

> (a) simplify access regulation for all parties;
>
> (b) consolidate access to the Victorian transmission system into a single streamlined process, which would lower the barriers to entry for gas retailers;
>
> (c) ensure an even playing field by applying the market carriage system under the MSO rules to the whole of the GasNet system; and
>
> (d) consistent with interstate practice, ensure there is one transmission access arrangement for each major pipeline system.[9]

GasNet proposes the following process:

- terminate the WTS Agreement between GasNet and TXU;
- revise the PTS and WTS access arrangements to merge them;
- VENCorp exercises its right under the WTS Approved Connection Deed to declare the WTS to be part of the 'gas transmission system', with effect from 1 January 2003. GasNet states that the WTS would be automatically covered by the PTS access arrangement; and
- apply the principles contained in section 8.9 of the Code to determine the capital base of that part of the enlarged PTS constituted by the current WTS.

A number of interested parties commented on GasNet's proposal. While there is support in principle for introducing a single consistent capacity management system across GasNet's system, some reservations were expressed about its implementation.

Of particular concern to a number of parties was that the merging of the two access arrangements should not give rise to any cross-subsidisation between the PTS and the

9 GasNet submission, 27 March 2002, p. 24.

WTS.[10] It was also suggested that greater transparency was needed in terms of the benefits of including the WTS in the PTS asset base.[11]

EnergyAdvice expressed concern that TXU would maintain its current monopoly of firm transportation capacity on the WTS consequent to the proposed allocation of Authorised Maximum Daily Quantity (AMDQ) credits, and suggested that they might instead be allocated to end-users.[12] EnergyAdvice also raised a number of questions about the future availability of capacity on the WTS.[13] Details of future availability are being settled through the allocation process being carried out by VENCorp.

TXU submitted that it was satisfied that work completed to date on the allocation of AMDQ credits was expected to preserve its pre-existing contractual rights with respect to the WTS.[14] TXU advised that it will terminate the WTS Agreement provided the Commission approves GasNet's merger proposal as part of its revised access arrangement and that the Service Envelope Agreement (SEA) 'is amended to VENCorp's satisfaction to ensure that the WTS and associated assets, performing to acceptable standards, are incorporated in the system operated by VENCorp under the MSO Rules'.[15]

In considering concerns expressed that TXU would maintain its current monopoly rights to firm capacity on the WTS, the Commission is cognisant of the requirement under section 2.47 of the Code that it must not approve revisions to an access arrangement if they would have the effect of depriving a person of a pre-existing contractual right (other than an exclusivity right which arose on or after 30 March 1995). The Commission considers that the proposed approach suitably maintains existing rights. It is not aware of any feasible alternative approaches that would preserve existing rights.

The Commission is aware of a proposal currently before the National Gas Pipelines Advisory Committee (NGPAC) to amend the Code so that it would specifically provide for the merging of two or more access arrangements.[16] It is the Commission's view that current Code provisions need not preclude it from approving revisions to the PTS and WTS access arrangements in the form of a single document covering both the PTS and the WTS. However, the relevant provisions and principles of the Code must be satisfied. The Commission's assessment of the merger proposal in terms of its impact on the capital base and on reference tariffs is set out in chapters 4 and 8 respectively.

One of the issues identified by NGPAC was that a merger could alter patterns of cost allocation and revenue recovery and, potentially, stranded asset risk. NGPAC raised

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10 For example, BHP Billion submission, 17 May 2002, p. 10; Amcor and PaperlinX submission, 24 June 2002, p. 9.

11 ENERGEX submission, 9 May 2002, p. 6.

12 EnergyAdvice submission, 30 May 2002, pp. 7-8.

13 EnergyAdvice submission, 19 September 2002, p. 3.

14 TXU submission, 31 May 2002, p. 5.

15 ibid., pp. 5-6.

16 NGPAC, *Information Memorandum: Proposed Amendment to the National Third Party Access Code for Natural Gas Pipeline Systems*, April 2002.

the issue of whether there would be a need 'to balance the issues arising from any winners and losers created by the merging of Access Arrangements applying to two or more Covered Pipelines'.[17]

The Commission has considered the potential costs and benefits of merging the access arrangements. It has decided to accept GasNet's proposal that the revised access arrangement will be in respect of both the PTS and the WTS. However, it has concerns about the potential impact of a merger on existing customers' expectations and rights.

The Commission generally is of the view that the merger of two or more access arrangements should not result in a substantial net transfer of risks or costs between customers. Nonetheless, some shifts may be acceptable in view of overall benefits expected from the merger (such as from administrative and regulatory efficiencies).

When the Commission approved separate access arrangements for the PTS and the WTS in 1998 it noted the expectation that the two systems would become physically connected in the future. It also noted the expectation that the WTS would become a market carriage pipeline and its access arrangement would be amended accordingly.[18]

Although two separate proposed access arrangements were submitted for approval in 1997, the Commission assessed the applications through a joint approval process. The WTS was treated as one of nine tariff zones. While the tariffs approved at the time were generally cost-reflective, the methodology adopted allowed some transfer of costs. For example, the use of optimised replacement cost (ORC) to allocate costs across the combined systems meant that capital costs associated with newer assets would also be paid for by customers using older assets.

The K factor mechanism approved as part of the tariff control formulae for the PTS access arrangement excluded the WTS. As a result, under or over recoveries of revenue as a result of product mix varying from forecasts could only be recouped from tariffs paid by users of the PTS. While the current arrangements do not allow any 'cross subsidy' through the K factor mechanisms between the two systems the Commission considers it appropriate that the two access arrangements be integrated.

The operation of the K factor mechanism is discussed in chapter 6.

2.3.2 Regulation of GasNet's Dandenong LNG facility

Clause 4.2 of the Market and System Operations Rules (MSOR) governs the obligations of VENCorp, GasNet and retailers in relation to GasNet's Liquefied Natural Gas (LNG) storage facility located at Dandenong. In particular, GasNet is required to make available to VENCorp 3 000 tonnes of LNG storage capacity for use by VENCorp to meet its operational requirements and to ensure the security of the gas transmission system.

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17 ibid., p. 4.

18 ACCC, 1998 Final Decision, p. 7.

The role of the system security reserve is to allow the maintenance of adequate system pressures in the event of a major emergency requiring a complete shutdown of the system so that customer load can be disconnected safely.

Under the provisions of the access arrangements, VENCorp pays GasNet $1.4 million a year for LNG storage which it recoups from its users through a commodity based charge. The balance of the facility's 12 000 tonne capacity is contracted to the three foundation retailers. The LNG facility is regulated under the Tariff Order until 31 December 2002.[19]

Clause 4.2 of the MSOR sets out the rights and responsibilities of GasNet, VENCorp and market participants relating to the operation of the LNG storage facility and the provision of LNG storage services. Pursuant to clause 4.2.5(b) an amount of 3 000 tonnes of LNG storage capacity is currently set aside as a system security reserve. VENCorp is obliged to maintain this amount in reserve and currently has a contract (put in place by the Victorian Government) with GasNet, the sole provider of LNG storage, to provide this capacity. The Commission understands that VENCorp is currently negotiating terms with GasNet for the future supply of system security reserve LNG capacity.

A number of interested parties considered that GasNet is in a position to exercise market power in the supply of LNG services in relation to the PTS, in particular, with regard to the system security reserve. Alternative sources of peak gas such as the UGS are not seen as a complete substitute for the Dandenong reserve at present because of factors such as location, slower response times and the amount of capacity likely to be available.

VENCorp commissioned a study by Charles River Associates which stated in the introduction that:

> VENCorp has undertaken a risk review based on a single event analysis (n-1) and has modelled a set of contingency scenarios in consultation with the Gas Market Consultative Committee (GMCC) and the Office of Gas Safety (OGS). This indicated that the minimum reserve for the LNG facility under these conditions should be 3,000 tonnes of LNG and this has been accepted by the industry. This means that the 3,000 tonnes of LNG reserve will be held out of the market and never used in the market, but rather will be reserved solely for system security purposes.[20]

The study confirmed the requirement to retain a reserve level of 3 000 tonnes and further noted that the refill rate was critical to ensure that sufficient reserves remained available for multiple contingencies.

ENERGEX submitted that there is a need to continue to regulate prices with respect to the system security reserve but not for the balance of the capacity of the Dandenong facility.[21] ENERGEX asked that the Commission satisfy itself that the price negotiated for the system security reserve is 'fair and reasonable' and stated its preference for

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19 The system security component is currently regulated as a 'scheduled excluded service' while the remainder is regulated as an 'non-scheduled excluded service'.

20 Charles River Associates, *Victorian gas systems security cost benefit risk analysis*, March 2002, p. 5.

21 ENERGEX submission, 9 May 2002, p. 3.

regulation ‘as long as it is a monopoly activity’.[22] Pulse suggested that the system security reserve could be considered to be ‘a required ancillary service and therefore not subject to normal commercial negotiations’.[23] Pulse considered it would be improper for GasNet to price this capacity to make up for any revenue shortfall.[24] TXU considered, depending on the outcome of the commercial negotiations between GasNet and VENCorp, that it may be appropriate for the Commission to consider inclusion of LNG storage for system security purposes as a reference service.[25]

The provisions of the Tariff Order under which the Commission currently regulates LNG storage for system security purposes are scheduled to cease to have effect after 31 December 2002. Accordingly, the Commission has considered suggestions that it may be appropriate for it to continue to regulate these services in terms of the provisions of the Code and the Gas Pipelines Access Law (GPAL).

For this reason, the Commission has considered whether the Dandenong LNG reserve is part of the PTS. Schedule A to the Code lists pipelines such as the PTS which were covered from the commencement of the Code. However it does not provide details of the individual assets included. For the purposes of the Code:

> "pipeline" means a pipe, or system of pipes, or part of a pipe, or system of pipes, for transporting natural gas, and any tanks, reservoirs, machinery or equipment directly attached to the pipe, or system of pipes, but does not include—
>
> (a) unless paragraph (b) applies, anything upstream of a prescribed exit flange on a pipeline conveying natural gas from a prescribed gas processing plant; or
>
> (b) if a connection point upstream of an exit flange on such a pipeline is prescribed, anything upstream of that point; or
>
> (c) a gathering system operated as part of an upstream producing operation; or
>
> (d) any tanks, reservoirs, machinery or equipment used to remove or add components to or change natural gas (other than odourisation facilities) such as a gas processing plant; or
>
> (e) anything downstream of the connection point to a consumer;[26]

From this definition, it is apparent that tanks and reservoirs directly attached to the GasNet system would be covered providing *inter alia* that they did not change natural gas. However, liquefaction and subsequent vapourisation processes carried out at the Dandenong facilities could be viewed to constitute changes to natural gas in terms of temperature, pressure and phase transition chemistry. Legal advice obtained by the Commission suggests that the facilities are not part of a covered pipeline. The Commission also noted that the reservoir is connected to the system by liquefaction and vapourisation equipment rather than being directly attached.

The Commission has also considered whether the LNG system security reserve is an ancillary service for the purposes of the Code. Its legal advice is that the Code is

[22] ibid., p. 7.

[23] Pulse submission, 16 May 2002, p. 4.

[24] ibid., p. 5.

[25] TXU submission, 31 May 2002, p. 15.

[26] Part 1 of Schedule 1 to the *Gas Pipelines Access (South Australia) Act 1997*.

unclear in this area. The Commission does not propose to regulate the LNG system security reserve once the relevant provisions of the Tariff Order cease to have effect.

2.3.3 Market carriage

The Victorian Government proposed the adoption of a market carriage capacity management system for the PTS as part of its reforms of the Victorian gas industry. The Commission considered opposing views from interested parties on the merits of this system as part of its approval of the transmission access arrangements in 1998. For example, supporters considered that market carriage could provide retailers and their customers with a sufficient degree of certainty of access to transmission services and that it would facilitate entry and exit by participants. In contrast, opponents suggested that the proposed approach was novel, untried and complex, and that it would inhibit interstate trade in natural gas as other states would adopt the alternative contract carriage approach.

The Commission concluded that the Victorian market carriage approach is consistent with the Victorian Code's guiding principles and criteria. It also concluded that interstate trade was unlikely to be hindered by the different systems in Victoria and other states. Accordingly, it approved the PTS access arrangements incorporating the market carriage capacity management system.

Both GasNet and VENCorp have proposed to continue under the market carriage capacity management system. Pursuant to section 3.8 of the Code, the Victorian and New South Wales ministers have given notice to the Commission permitting use of the market carriage model for the second access arrangement period for those parts of the PTS in their respective jurisdictions. In addition, the Commonwealth Minister certified the Victorian gas access regime as effective in accordance with section 44N of the *Trade Practices Act 1974* in March 2001.

The Commission is aware that a number of interested parties continue to hold concerns about the current market structure.[27] However, section 205 of the Victorian *Gas Industry Act 2001* (GIA) requires that a review of Part 8 of that Act, which covers VENCorp's operations and functions, must be undertaken in 2007 and completed by 31 December 2007. The review will address whether or not there is a continuing need for VENCorp, or a similar statutory authority. It must have particular regard to the competitiveness of markets for and in relation to gas. The Commission expects that the review will examine the overall market structure and operations in Victoria, including the market carriage capacity management system and the role of VENCorp as independent system operator. Accordingly, the Commission has not assessed the current market structure or the relative merits of the two capacity management systems as part of the current review.

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27 See for example, EAG submission, 31 May 2002, p. 1.

2.3.4 Interaction with VENCorp's access arrangement

Under GasNet's proposals a single PTS access arrangement would apply from the beginning of the second access arrangement period, with GasNet the owner, and VENCorp the operator.[28]

Users relate directly with GasNet in relation to connection to the physical pipeline system, while their relationship with VENCorp is principally in terms of its market role.

VENCorp's ability to perform its statutory role as independent system operator is dependent on GasNet and the SEA. Hence, clause 5.1.1 of the MSOR requires that a SEA be in force at all times under which GasNet:

> agrees, amongst other things, to provide to VENCorp gas transportation services and pipeline capacity by means of the [PTS] pipelines.

TXU stated in its submission:

> TXU must deal regularly with GasNet. Through Gas Transportation Deeds and the Service Envelope Agreement, GasNet invoices TXU, and requires TXU to pay for Tariffed Transmission Services directly to GasNet. When TXU seeks a new connection, or additional capacity on the system, it must deal directly with GasNet.[29]

Under the terms of the Code (sections 10.1 and 10.2), GasNet and VENCorp are 'multiple service providers' with responsibility for complying with the Code. Their PTS access arrangements allocate responsibility between them for complying with the obligations imposed by the Code. Currently, the GasNet and VENCorp PTS access arrangements each contain all the minimum elements set out in section 3 of the Code other than that responsibility for extensions and expansions is solely allocated to GasNet and responsibility for the queuing policy is allocated to VENCorp.[30] The Commission approved this approach in 1998 as it considered it provided an appropriate allocation of responsibility between the two service providers.[31]

VENCorp proposes to maintain the status quo for the second access arrangement period with regard to its relationship with GasNet. In contrast, GasNet proposes a number of changes. In particular, GasNet states that it is VENCorp that is responsible for the provision of the reference service and that GasNet does not propose to make any reference services available to users or prospective users under its revised access arrangement.[32] Accordingly, it would not specify the terms and conditions of supply of reference services.[33]

Clause 5.2.2 of the GasNet access arrangement currently states that it will make the tariffed transmission service available to VENCorp on the terms and conditions and in

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[28] GasNet, rather than VENCorp, currently operates the western system.

[29] TXU submission, 19 April 2002, p. 3.

[30] As the PTS is operated under a market carriage capacity management system, neither access arrangement is obliged to contain a trading policy.

[31] The allocation is discussed in section 11.5 of this Draft Decision.

[32] See section 11.1 of this Draft Decision.

[33] See section 11.2 of this Draft Decision.

accordance with GasNet's reference tariff policy. GasNet's terms and conditions (clause 5.4.1) state that GasNet will make the PTS available to VENCorp as user in accordance with its obligations under the SEA and that VENCorp will then provide services to users of the PTS in accordance with the MSOR.

GasNet acknowledges that it provides services to VENCorp through the SEA but 'considers that the characterisation of the Reference Service and the description of VENCorp as "User" in the current Access Arrangement are inconsistent with the Code'.[34] GasNet considers that VENCorp already has its entitlement to system availability under the SEA and so does not need the current specification of the reference service. GasNet's reference service proposal is assessed in chapter 11.

Consistent with this approach, GasNet's access arrangement would not contain terms and conditions. GasNet's access arrangement would instead state that the terms and conditions on which the reference service is supplied are as set out in the MSOR.

VENCorp submitted that its preference is for the existing allocation to at least continue, such that both access arrangements would describe the reference services they provide and the associated terms and conditions. VENCorp considers that GasNet's access arrangement should include the SEA, either in full, or the key obligations.[35] VENCorp noted that GasNet accounts for around 85 per cent of the total annual transmission costs for the PTS and suggested it would be unacceptable if associated reference tariffs were not defined in GasNet's access arrangement. VENCorp expressed concern that GasNet might be able to alter its services such that they were in conflict with the statutory functions of VENCorp as operator of the PTS and that prospective users could be precluded from recourse to GasNet in regard to services it provides under the Code's access dispute processes.[36]

A number of other interested parties expressed support for the view put by VENCorp.[37]

The Victorian transmission access arrangements are unique in that there are two independent service providers, GasNet and VENCorp, providing third party access over the same system. In such a situation, the Code (sections 10.1 and 10.2) allows service providers to submit either a joint access arrangement or separate access arrangements. Under either approach, an appropriate allocation of responsibilities between the parties for complying with the Code is required. Where two separate access arrangements are submitted by multiple service providers the Commission must assess whether the access arrangements together meet the requirements of the Code. The Commission was satisfied that these conditions were met when it approved the access arrangements in 1998.

The Commission's strong preference is for multiple service providers to adopt an agreed allocation of responsibilities and a consistent approach when proposing access

34 GasNet submission, 27 March 2002, p. 122.

35 VENCorp submission, 13 May 2002, p. 4.

36 ibid., p. 4.

37 For example, ENERGEX submission, 9 May 2002, pp. 1-2; DNRE submission, 22 May 2002; Pulse submission, 16 May 2002, p. 3; TXU submission, 31 May 2002, p. 3; BHP Billiton submission, 17 May 2002, p. 9.

arrangements or revised access arrangements for approval. However, in this instance GasNet and VENCorp have been unable to agree on a consistent approach.

The Commission has carefully considered the service providers' proposed approaches, taking into account legal opinions provided to the Commission and the views of interested parties. The Commission notes that, apart from GasNet and its legal advisers, all views advanced supported GasNet continuing to provide a reference service.

The Commission would be reluctant to approve revisions to access arrangements involving multiple service providers if the outcome would be to shift the balance of existing rights between those service providers without their agreement. In this instance VENCorp opposes such a change which it considers would prejudice its existing rights. The Commission's assessment of GasNet's services policy is provided in chapter 11 of this Final Decision.

The Commission has considered VENCorp's proposal that the SEA should, in part or in full, be included as part of the revised GasNet access arrangement. Consistent with current arrangements, it considers it unnecessary for the SEA to be included but that it should be publicly available. Both GasNet and VENCorp have agreed to make an up to date version of the SEA publicly available.

The Commission proposed amendments in its draft decisions to both service providers' proposals. VENCorp agreed to amend its revised access arrangement as proposed, but stated that this would be contingent on GasNet's services policy being amended appropriately.[38] GasNet reiterated its position that it does not provide a service to VENCorp within the meaning of the Code.[39]

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38 VENCorp submission, 13 September 2002, p. 5.

39 GasNet submission, 20 September 2002, p. 41.

Part B – Tariff issues

3. Reference tariff methodology

3.1 Introduction

This chapter first assesses the reference tariff policy proposed by GasNet to apply during the second access arrangement period. It then considers the reference tariff approach proposed by GasNet to apply during that period. A number of changes are proposed for the revised reference tariff policy.

3.2 Reference tariff policy

3.2.1 Code requirements

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. This reference tariff policy must, in the regulator's opinion, comply with the reference tariff principles set out in section 8 of the Code.

Pursuant to section 8.47 of the Code, a service provider's reference tariff policy may provide that certain principles are fixed for a specified period and are not subject to change when it submits revisions to its access arrangement without its agreement.

3.2.2 Current access arrangement provisions

GasNet's reference tariff policies are currently described in clauses 5.3.2 to 5.3.8 of the PTS and WTS access arrangements which contain similar provisions.[40] These include:

- adoption of a consumer price index (CPI)-X price path approach;
- the treatment of new facilities investment that does not satisfy the requirements of section 8.16 of the Code and the use of a speculative investment fund;
- adjustment of the capital base to take into account wholly or partly redundant assets;
- an incentive mechanism that allows GasNet to retain a share of returns achieved in the first access arrangement period in excess of anticipated returns;
- annual adjustment of tariffs in accordance with the price control formula. GasNet must provide the Commission with a statement proposing revised tariffs at least 30 business days prior to the commencement of the next regulatory year. The statement must demonstrate compliance with the price control formula. If the Commission has not notified GasNet that it has approved the proposed revised tariffs within 20 business days it is taken to have approved the proposed revised tariffs as of the 21st business day; and

[40] Some aspects of the PTS access arrangement, such as the initial reference tariffs, and the methods applicable to changing reference tariffs, are contained in the Tariff Order.

- a tax events pass through mechanism that allows reference tariffs to be adjusted in line with increases or decreases in taxation affecting the provision of those references services without undergoing a review process under section 2 of the Code. GasNet may provide the Commission with a relevant statement providing details of the proposed pass through within three months of a change in taxes event occurring. If the Commission has not notified GasNet that it has approved the proposed pass through within 20 business days it is taken to have approved the proposed pass through as of the 21st business day. If a change in taxes pass through event occurs which is likely to affect GasNet but GasNet does not provide the Commission with a statement, the Commission may decide on a pass through amount and the basis on which it would apply.

GasNet's access arrangements currently include fixed principles which can be summarised as:

- use of incentive-based regulation under a CPI-X approach (not rate of return);
- an unchanging X factor over the second access arrangement period;
- adjustment of the initial capital base for inflation, depreciation, wholly or partially redundant assets and additions and disposals;
- a fair sharing of any benefits achieved through efficiency gains in later access arrangement periods;
- have regard to the need to take into account any K factor carryover;
- have regard to the cost of making, producing or supplying the goods or services which GasNet makes, produces or supplies;
- have regard to relevant benchmarks (including with regard to the level of executive remuneration); and
- that the Commission may issue statements of regulatory intent.

3.2.3 GasNet proposal

Clause 4.1 of GasNet's proposed revised access arrangement states that the access arrangement governs the transmission tariffs, which GasNet describes as being the portion of the reference tariff applicable to the tariffed transmission service.

GasNet (clause 4.2) states that the proposed initial transmission tariffs are set out in schedule 1 to the proposed revised access arrangement exclusive of Goods and Services Tax (GST). The transmission tariffs comprise rules and billing parameters, the GST-exclusive tariffs plus the amount of GST.

GasNet proposes that the tariffs will continue to vary on the basis of a price path approach whereby a set of prices and a price control mechanism are determined on an ex ante basis and the mechanism is not adjusted to account for subsequent events until the commencement of the next access arrangement period (clause 4.3).

Clause 4.4 states that the transmission tariffs have been determined on the basis of new facilities investment that is forecast to occur within the second access arrangement period and is reasonably expected to pass the requirements in section 8.16 of the Code.

GasNet proposes that it may submit revisions to its access arrangement during the second access arrangement period to increase the capital base of the PTS in recognition of further new facilities investment that satisfies section 8.16 of the Code.

Consistent with the access arrangements as they currently stand, GasNet proposes that it may undertake new facilities investment that, in total, does not satisfy the requirements of section 8.16 of the Code, (GasNet refers to this as speculative facilities (clause 4.5)). GasNet states that the portion of this new facilities investment which does satisfy the requirements of section 8.16 of the Code may, on a revision application by GasNet, be incorporated into the capital base. The remaining portion would form part of the speculative investment fund. This amount, or a part of it, 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 speculative facilities change such that any part of the speculative investment fund would then satisfy the requirements of section 8.16. The amount of the speculative investment fund would be calculated in accordance with section 8.19 of the Code.

GasNet (clause 4.6) proposes that the Commission would continue to review, and if necessary, adjust the capital base (at the start of the next access arrangement period) to take account of wholly redundant assets. It would no longer allow an adjustment for partially redundant assets.

GasNet (clause 4.7) proposes that the incentive mechanism currently included in the access arrangement be retained but in revised form (see schedules 3 and 4 of the proposed revisions and chapter 6 of this Final Decision).

GasNet proposes to revise its current tax pass through mechanism such that decreases in tax would only be recognised as net adjustments to tax increases (see clauses 4.9 and 6). It also proposes that a pass through mechanism apply to changes in events and insurance costs. Following receipt of a statement from GasNet, the Commission would determine:

- if the specified event has occurred, or will occur;
- the pass through amount; and
- the manner in which the pass through amount would be applied.

In a response to submissions, GasNet clarified that the common feature of these pass through events is that they are all beyond the company's control.[41]

GasNet's proposed pass through amount and manner in which it would be applied would be taken to be approved if the Commission did not notify GasNet that it did not approve the statement within 20 business days of its receipt.

GasNet also proposed a zone change mechanism that would allow GasNet to submit revisions if it believes that zones specified in schedule 2 require amendment (see clause 4.10). In response to receipt of a statement from GasNet the Commission must decide whether to approve the amendment and ensure that the amendment is consistent with

[41] GasNet response to submissions, 12 June 2002, p. 15.

the cost allocation methodology used to determine tariffs. As with the pass through, the proposed zone change amendment would be taken to be approved if the Commission does not notify GasNet that it did not approve the statement within 20 days of its receipt.

Under clause 3.3 of schedule 3 to GasNet's proposed revised access arrangement an annual tariff adjustment would be taken to be approved if the Commission did not notify GasNet that it did not approve the statement within 15 business days of its receipt.

GasNet states that any amendment to the transmission tariffs in the second access arrangement period made under or as contemplated by clauses 4.2, 4.3, 4.7, 4.9, 4.10 or 6 constitutes an amendment under GasNet's reference tariff policy and does not constitute a revision of its access arrangement under the terms of the Code.

In addition, the proposed revised reference tariff policy includes the following fixed principles for the second access arrangement period (to apply for the third access arrangement period):

- the Commission would include in the reference tariffs for the third access arrangement period an allowance for the K factor carryover adjustment based on actual figures (or estimates where actual figures are not available);[42] and
- GasNet would be able to retain a reasonable share of the benefits of efficiency gains it achieves in the second access arrangement period. Efficiency gains would be calculated on the basis of the amount that the average forecast operating costs for the third access arrangement period are below the forecast operating costs for the last year of the second access arrangement period adjusted to account for additional workload.[43]

3.2.4 Submissions to Issues Paper

A number of parties commented on aspects of GasNet's proposed revisions to its reference tariff policy. Parties were generally supportive of the broad approach proposed including the use of a CPI-X price path methodology and incentive regulation. However, reservations were expressed on the details of a number of issues. These are generally considered under specific topics below.

VENCorp stated that the proposed mechanism allowing amendments to zones would have the potential to require VENCorp, distributors and retailers to put in place new business processes and IT systems.[44] VENCorp considered that GasNet's proposed mechanism for amending zones within an access arrangement period should provide for a process of public consultation.

BHP Billiton opposed the revised redundant capital policy proposed by GasNet. It suggested that partially used assets should be optimised so that fully utilised assets do

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[42] The K factor mechanism is discussed in section 6.2.2 of this Final Decision.

[43] Benefit sharing is discussed in section 10.1 of this Final Decision.

[44] VENCorp submission, 13 May 2002, p. 12.

not cross subsidise under utilised assets. The Energy Users Association of Australia (EUAA) expressed a similar view.[45]

The Allen Consulting Group (ACG), on behalf of ExxonMobil, proposed that GasNet's redundant capital policy should specifically provide a mechanism that would apply to the Southwest Pipeline in the event that it were to be included in the capital base.[46] ACG was concerned that this investment will not in practice be viable and considers that, if this is the case, its costs should not be borne by other users of the PTS.

With regard to the pass through proposal, TXU submitted that the pass through for tax increases seems reasonable, but a pass through for regulatory requirements and increased insurance premiums is not consistent with GasNet's incentive mechanism. TXU noted that if the Commission allows this mechanism, it should ensure that the appropriate level of consultation with users occurs prior to its approval, and that GasNet is only allowed to pass through the cumulative impact of any pass through event.[47]

Origin accepted the pass through mechanism in principle but suggested a number of changes to GasNet's proposal. Origin stated that the pass through mechanism should be two-way so as to cover decreases as well as increases in costs, and contended that the 20 business day approval process be rejected in its current form.[48]

Pulse submitted that the Commission should assess whether the inclusion of Insurance and Regulatory Events is consistent with the weighted average cost of capital (WACC) being claimed by GasNet, and that the widening of the definition of pass through events represents a move towards rate of return regulation.[49]

ENERGEX expressed concern that user charges can increase without due regulatory process under the proposed pass through mechanism. It proposed that the Commission should make the pass through clause more consultative to allow those affected to have input into the decision making process.[50] VENCorp submitted that the definition of a Regulatory Event is very wide under the GasNet proposal, and argued that the GasNet proposal appears open-ended, lacks transparency and could allow GasNet to introduce tariff increases without any consultation. VENCorp proposed that the Gas Marketing Committee and MSOR change process provide forums whereby GasNet can raise any increases in costs.[51]

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45 BHP Billiton submission, 21 June 2002, p. 30; EUAA submission, 11 July 2002, p. 8.

46 ACG, *Implementation of incremental pricing for the Southwest Pipeline* (ExxonMobil submission, 5 June 2002), p. 24.

47 TXU submission, 31 May 2002, pp. 26-27.

48 Origin submission, 17 May 2002, p. 3.

49 Pulse submission, 16 May 2002, p. 4.

50 ENERGEX submission, 9 May 2002, p. 5.

51 VENCorp submission, 13 May 2002, p. 13.

3.2.5 Draft Decision

The Commission's considerations of a number of these proposals was included as part of broader assessments under specific topics later in the Draft Decision. They are also referred to in the corresponding sections of this document. In particular:

- the treatment of new facilities investment was considered in section 11.3 of the Draft Decision;
- K factor carryover was considered in chapter 6 of the Draft Decision; and
- incentive mechanisms were discussed in chapter 10 of the Draft Decision.

The Draft Decision assessment of other proposals is discussed in this section.

The Commission noted that the broad approach proposed of CPI-X price path methodology and incentive regulation is generally uncontroversial.

Redundant capital policy

Consistent with the current provisions of the access arrangements, under clause 4.6 of the proposed revised access arrangement, the Commission would continue to be able to adjust the capital base for wholly redundant assets at the start of the next access arrangement period. However, under GasNet's proposal it would no longer be able to make an adjustment for partially redundant assets.

The Commission considered GasNet's view that the ability to adjust for partially redundant assets may create uncertainty because it would not be clear before the event as to what extent an asset may be redundant before it is to be removed from the capital base. GasNet questioned whether partial utilisation of a particular pipeline in a particular year could result in the pipeline being excluded from the asset base.

The Commission considered that GasNet's concerns about the potential treatment of partially redundant assets suggested an exaggerated application of Code provisions. Most importantly, section 8.27(b) of the Code is relevant to partial utilisation which indicates a sharing of costs associated with a decline in the volume of sales rather than complete exclusion of assets from the capital base. In addition, redundancy is a forward-looking concept. While historical performance may be a useful indicator of likely future performance, it is the expectation of future usage that the Commission must assess when considering redundancy. Further, the Draft Decision noted that an adjustment for redundant capital would only be made if there is a reasonable expectation of a permanent reduction in usage. Nonetheless, section 8.28 allows for assets where they have been treated as redundant capital but are subsequently used, or used to a greater extent, to be readmitted to the capital base.

The Draft Decision acknowledged that the current provisions of GasNet's access arrangement with regard to capital redundancy involve elements of uncertainty for GasNet. However, partial redundancy provisions can provide an important safeguard for users, particularly with capital intensive network infrastructure such as the PTS. Even in the face of apparent redundancy, it may be commercially viable to continue some residual usage of these systems. A policy that only removed totally redundant capital from the asset base might in practice provide little protection for users who would pay tariffs to recover the total cost of partially redundant assets. The

Commission also noted that, in general, the existence of a capital redundancy policy encourages a service provider to ensure that its investments are appropriate.

The Commission was not persuaded that it should agree to the risks associated with partial redundancy being fully shifted to users. Accordingly, the Draft Decision included a proposed amendment that the existing redundant capital policy be retained by GasNet.

Pass through and zone change mechanisms

The Commission considered GasNet's proposed pass through and zone change mechanisms and the proposed changes to annual tariff review procedures. Changes under these provisions are not considered by GasNet to be revisions to the access arrangement.

In the Draft Decision the Commission noted that GasNet responded to VENCorp's concerns about the need for public consultation in relation to individual pass through events as follows:

> It is within the discretion of the Commission to withhold its approval pending consultation. The proposal as put by GasNet gives the Commission the discretion to decide its course of action based on the materiality of the proposed changes.[52]

The Commission agreed that it should have the discretion to conduct a process of public consultation in response to proposals under these proposed provisions. It noted that the Code (section 2.33(b)) specifies a public consultation process for revisions that are material and for all changes to reference tariffs and reference services. However, GasNet's proposal makes no explicit allowance for such a process and the proposed timeframes would appear inadequate to allow for consultation or other aspects of due process which may be needed if the Commission accepts GasNet's expanded tariff change proposals. The Commission noted that the existing timeframes have been adequate for the limited assessment associated with annual tariff adjustments and tax events pass through to date, but that the proposed expanded scope of these change mechanisms could require a broader assessment.[53]

In practice, under GasNet's proposal, in order to allow sufficient time for due process (including public consultation as appropriate) on a specific proposal put forward by GasNet, the Commission would need to decide to not approve a proposal and notify GasNet accordingly. This process could be repeated until sufficient time had elapsed for public consultation to be completed and for the Commission to decide to approve the proposal. The Commission considered that this process would be unnecessarily constraining and unwieldy. Circumstances which may warrant an extended assessment period include proposals that are complex and where inadequate information is provided. Accordingly, changes to streamline the process and to provide adequate time to allow due process were proposed in the Draft Decision.

GasNet proposed in its revised access arrangement that the Commission approve only positive pass through amounts (clause 6.4). In a response to submissions, GasNet

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[52] GasNet response to submissions, 12 June 2002.

[53] The Commission has 20 business days to approve proposed revised tariffs.

supported its case by arguing that a negative pass through would encourage disputes from users, and that any pass through event must take into account the effect of any previous event, including negative events.[54]

The Commission did not accept GasNet's proposal on the basis that it considered a pass through mechanism should apply to both increases and decreases in costs and proposed an amendment that the pass through mechanism allow both positive and negative pass through amounts.

The Commission also noted that the Essential Services Commission (ESC) considered that similar pass through mechanisms proposed by the three Victorian gas distribution businesses should provide a mechanism to allow it to initiate pass through reviews.[55] This amendment was proposed as the ESC considered it would be unlikely for a service provider to initiate a pass through that will lead to a decrease in reference tariffs. The Commission agreed with the ESC and proposed an amendment that would allow it to initiate pass through reviews.

While the Commission had some concerns about the muting effect that a pass through mechanism would have on incentives, it recognised that the Code (section 8.3) explicitly allows for a cost of service methodology (section 3.3 of this Final Decision).

GasNet proposed that the pass through mechanism would operate for three categories of events: a change in taxes event, a regulatory event and an insurance event. The Commission considered that it is not unreasonable to allow a pass through mechanism for these events as it can provide a cost-effective approach to dealing with uncertain future costs, but that specifics of the pass through mechanism should be amended.

In relation to the Change in Taxes Event, GasNet defined such an event as:

> (a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of Relevant Tax); or
>
> (b) the imposition of a new Relevant Tax,
>
> to the extent that the change or imposition:
>
> (c) occurs after the Commencement Date; and
>
> (d) results in a change in the amount GasNet is required to pay or is taken to pay (whether directly or under any contract) by way of Relevant Taxes.[56]

GasNet defined a Relevant Tax as:

> any tax, rate duty, charge, levy or other like or analogous impost paid or taken to be paid by GasNet associated with the Tariffed Transmission Service, but excludes income tax and capital gains tax.[57]

The Commission expressed the view in its Draft Decision that GasNet's definition of a Change in Taxes Event was not appropriate as it excluded a provision for the removal

[54] GasNet response to submissions, 12 June 2002, p. 15.

[55] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 166.

[56] GasNet access arrangement, 27 March 2002, p. 12.

[57] ibid., p. 14.

of a tax (making the approach asymmetrical), and that the proposed definition of a Relevant Tax was too broad. It therefore proposed that the definition of a Change in Taxes Event be amended so that (b) reads ‘the removal or imposition of a *Relevant Tax*’, and that the following definition of Relevant Tax, which was based on the wording of the current Tariff Order be used:

> *Relevant Tax:*
>
> Any tax but excluding any:
>
> (a) income tax (or State equivalent income tax), fringe benefits tax or capital gains tax;
>
> (b) payroll tax;
>
> (c) fees and charges paid or payable in respect of a *Regulatory Event,*
>
> (d) land tax or any other tax on the ownership or occupancy of premises;
>
> (d) customs and import duty;
>
> (e) municipal rates, taxes and other charges imposed by local authorities;
>
> (f) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;
>
> (g) penalties and interest for late payment relating to any tax; or
>
> (h) any tax that replaces any of the taxes referred to in (a) and (g),
>
> and in this definition, ‘tax’ includes any rate, duty, charge or other like or analogous post.

A similar approach was proposed by the ESC for the three Victorian gas distribution businesses.

The Commission considered that in order to make an informed decision on whether the pass through event proposed is appropriate, GasNet must provide to the Commission sufficient documentary evidence which substantiates that the aggregate tax costs facing GasNet have increased or decreased. It proposed that GasNet amend its access arrangement to provide for this information.

In relation to a Regulatory Event, GasNet defined such an event to mean:

> A decision made by the Commission or any other Authority or any amendment to an Applicable Law after the Commencement Date that has the effect of:
>
> (a) imposing minimum standards (including safety or technical standards) on GasNet relating to the Tariffed Transmission Service that are different from the set of minimum standards imposed on GasNet associated with the Tariffed Transmission Service at the Commencement Date;
>
> (b) altering the nature and scope of the services that comprise the Tariffed Transmission Service; or
>
> (c) substantially varying the manner in which GasNet is required to undertake any activity forming part of the Tariffed Transmission Service from the Commencement Date,
>
> As a result of which GasNet incurs materially higher costs associated with the Tariffed Transmission Service that it would have incurred but for that event.[58]

The Draft Decision proposed that the definition of a Regulatory Event be amended to incorporate both increases and decreases in regulatory requirements. It also proposed

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58 ibid.

that appropriate amendments to GasNet's access arrangement be introduced to require the submission of sufficient information when a pass through event statement is provided to the Commission. This information should include documentary evidence outlining the impact of any proposed Regulatory Event on aggregate company costs.

GasNet defined an Insurance Event as:

> Circumstances in which:
>
> (a) there has been a change in one or more costs in the insurance comprising GasNet's Minimum Insurance Level; and
>
> (b) as a result of that change, the aggregate costs of GasNet's Minimum Insurance Level exceeds the Benchmark Insurance Costs.[59]

The Commission stated that it was of the view that the definition of an Insurance Event should be amended to allow for a change in the Minimum Insurance Level that exceeds or falls short of the Benchmark Insurance Costs. As with the aforementioned pass through events, it was proposed that GasNet amend its access arrangement so that it is required to provide documentary evidence of a change in aggregate insurance costs to the Commission.

GasNet also sought a cash flow allowance for asymmetric risks. This allowance includes \$140 000 for deductibles in current insurance policies held by GasNet pursuant to the SEA. The Commission considered that there is some uncertainty in regard to whether the allowance will be sufficient. As a result, the Commission's Draft Decision proposed that the allowance not be included in the cash flows as proposed but actual expenditures be included in the pass through mechanism as an Insurance Event.

3.2.6 Response to Draft Decision

Redundant capital policy

No further submissions from interested parties commented on the redundant capital policy although ExxonMobil noted that the inclusion of partially redundant assets in the policy would assist in limiting 'the effect of the potential cross-subsidisation of the SWP by non-SWP assets'.[60]

In response to the Draft Decision, GasNet reiterated its view that it does not accept the inclusion of partially redundant assets in the policy on the basis that it creates uncertainty. It noted:

> ... that through the policy of cost reflective tariffs, it already bears the risk associated with partially redundant assets. If an asset becomes under-utilised, the tariff would need to increase to recover the revenue requirement. If this tariff is not sustainable, GasNet would need to defer depreciation in order to achieve a sustainable tariff. However, GasNet is at risk that if volumes do not grow in the future, then the deferred depreciation will not be recovered.
>
> GasNet considers that this approach to partial redundancy achieves a fair sharing of costs when assets are under-utilised ...[61]

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[59] ibid., p. 13.

[60] ExxonMobil submission, 10 September 2002, p. 1.

[61] GasNet submission, 20 September 2002, p. 4.

Pass through and zone change mechanisms

GasNet, in its submission to the Draft Decision, noted that the Commission's proposal for a 40 day pass through assessment period was reasonable, and that the inclusion of insurance deductibles in the pass through mechanism was appropriate. GasNet was silent on the issue of zone change proposals.

With regard to a negative pass through, GasNet argues that section 6.3(f) of its proposed revised access arrangement adequately deals with negative costs as it requires the Commission to take into account any previous pass through event, including negative pass through amounts, when assessing a new pass through application. GasNet also stated that it has not included a specific obligation for negative pass through events as such events are unlikely, given that pass through events are asymmetrical. Accordingly, it regards the proposed amendments to the definitions of 'regulatory event', 'change in tax event' and 'insurance event' are not warranted.[62]

GasNet criticised the Commission's proposed changes to the definition of 'relevant tax'. The definition is considered by GasNet to be too restrictive and give the pass through no substantive operation. GasNet suggests, as an example, that the mechanism effectively imposes the risk of increases in land taxes and taxes imposed by municipal authorities onto GasNet.[63]

AGL noted the Commission's amendment which increases the notification period that GasNet needs to provide for amending zone specifications but expressed the view that GasNet has a broad obligation to consult prior to proposing such changes.[64]

3.2.7 Final Decision

Redundant capital policy

GasNet has suggested that through a policy of cost reflective tariffs it bears the risk of partially redundant assets. The Commission acknowledges that under the present tariff structure GasNet would face this risk if the redundant asset was an entire zone. It should be noted that this risk may alter in the future if the tariff structure changes.

However, if only part of a zone becomes redundant the remaining users in that zone will incur an increase in tariffs to recover the cost of the now redundant asset. To the extent that these users will be able to bear an increase in tariffs, GasNet will be able to shift the cost of a redundant asset to users of the PTS.

In addition, if redundancy of an asset is not reflected in forecast volumes, the K factor can reallocate uncovered costs relating to an asset to the remainder of the PTS. The K factor mechanism is intended to address differences between actual average revenue and forecast average revenue. That is, it can compensate for changes in the product mix from year to year. As a result, GasNet is able to recover the costs from users of other assets. Users of other assets would effectively cross-subsidise the poor performing asset. While this mechanism has generally been accepted by the

62 ibid., p. 5.

63 ibid., p. 6.

64 AGL submission, 18 September 2002, p. 1.

Commission, it should be acknowledged that it does reduce some of the cost reflectivity of tariffs for the PTS and increase the ability to cross-subsidise.

Consequently, the Commission does not entirely agree with GasNet's claim that 'it already bears the risk associated with partially redundant assets'. It considers that the risk that GasNet bears is limited and consequently the redundant capital policy is particularly important for this access arrangement.

The Commission considers that it is important that GasNet faces appropriate investment signals for its pipeline (see section 8.1(d), (e) and (f) of the Code). Mechanisms, such as the redundant capital policy, that encourage appropriate and efficient investment in the assets help provide these signals. It is also in the interest of users and prospective users that tariffs recover the cost of providing the service which has been used (section 2.24(f)). It is not appropriate for users to bear a significant portion of the risk associated with redundant assets.

The Commission acknowledges that uncertainty regarding the capital base may arise for GasNet from a redundant capital policy that allows the partial exclusion of certain assets (and the possible re-inclusion under section 8.28 of the Code) that do not wholly contribute to the provision of the reference service. To the extent that the capital base may vary over time as partially redundant assets emerge, the policy also provides some uncertainty for users and prospective users. However, in assessing the uncertainty that may arise in accordance with section 8.27 of the Code, the Commission also notes that in this instance these uncertainties are outweighed by other factors, as discussed earlier, which support the inclusion of partially redundant assets in the redundant capital policy. In particular, the Commission notes that it is desirable that the access arrangement not distort investment decisions (section 8.1(d)) and that reference tariffs reflect the efficient cost of providing the reference service (section 8.1(a)).

In accordance with section 8.27 of the Code, the Commission has also taken into account the uncertainty arising from the redundant capital policy in the determination of the rate of return and the life of the assets. In particular, the value of the beta for GasNet was determined in reference to the redundant capital policy. Also, the Commission has agreed in this Final Decision to reduce the economic life of the Longford to Pakenham pipeline.

Accordingly, after considering the current redundant capital policy and the matters set out in sections 8.27, 8.1 and 2.24 of the Code, the Commission requires the revised access arrangement to be amended so that the redundant capital policy continues to apply to both partially and wholly redundant assets.

Amendment 1

GasNet must amend clause 4.6 of its revised access arrangement so that the redundant capital policy applies to both partially and wholly redundant assets.

Zone change mechanism

GasNet has proposed a mechanism in its revised access arrangement (clause 4.10) that would allow it to notify the Commission of changes to the specifications of zones. In determining whether to approve such an amendment under this mechanism it is proposed that the Commission would ensure that the amendment is consistent with the cost allocation methodology used to determine tariffs.

The Commission notes while the pass through mechanism relates to events that GasNet argues are all beyond its control, the zone change amendment is based upon whether GasNet believes that the zones in Schedule 2 of the proposed revised access arrangement require amendment (Clause 4.10(a)). The details of any associated amendments to the transmission tariff are left for GasNet to establish, subject to the Commission ensuring that the amendment is consistent with the cost allocation methodology used to determine the initial transmission tariffs.

The Commission considers that the proposed clause appears to provide GasNet with a considerable amount of discretion regarding zone amendments and associated tariff amendments. The range of amendments that it could encompass is broad and may range from adding a post code to a zone to amalgamating or dividing whole zones. It is reasonable to expect that the drafters of the Code intended more significant changes to give rise to the assessment and consultation process under section 2 of the Code.

GasNet has submitted that its proposed mechanism allows for public consultation at the discretion of the Commission.[65] Notwithstanding this, in assessing this proposed revision the Commission has taken into account the factors set out in section 2.24 (as required by section 2.46 of the Code). Section 2.24 requires the Commission to consider, among other things, the interests of users and prospective users and any other matters that the Commission considers are relevant. The Commission notes that it is difficult to predict the impact of a proposed amendment on users. Proposed clause 4.10 does not appear to be in the interests of users as no provision is expressly made for public consultation. For these reasons, the Commission does not consider such a mechanism to be appropriate to be included in the reference tariff policy. Instead, any such revision to the access arrangement should be dealt with in accordance with section 2 of the Code. In this regard the Commission notes that section 2.33 of the Code allows the regulator to dispense with the requirement for access arrangement information and public consultation if the revisions proposed are not material and will not result in changes to reference tariffs. The Commission considers that this would allow for changes such as adding a post code to a zone to be considered quickly, while changes such as dividing a zone could receive appropriate consideration.

The Commission considers that GasNet has not sufficiently demonstrated the need for its proposed mechanism in the reference tariff policy or indicated how the Code itself is inadequate to deal with amendments to zones. On that basis, the Commission considers that it is in the interests of users and the public (section 2.24 of the Code) that the Code continue to apply to any proposed revision to the zones.

Amendment 2

GasNet must amend its revised access arrangement by removing clause 4.10.

65 GasNet response to submissions, 12 June 2002, p. 14.

Pass through mechanism

Symmetrical pass through and insurance deductibles

As noted, GasNet claims that the proposed amendment in the Draft Decision to allow for negative pass through amounts is not appropriate. GasNet asserts that the mechanism proposed in the revised access arrangement will adequately deal with negative pass through amounts, and that negative amounts would be unlikely given the asymmetric nature of pass through events.

The Commission does not agree with GasNet on this issue. The pass through adjustment mechanism outlined in section 6.3(f) of GasNet's proposed revised access arrangement requires the Commission, when assessing a pass through application of a positive amount, to consider whether other pass through events have occurred and ensure the financial effect of the pass through amount is economically neutral. Pass through events are defined in the proposed revised access arrangement to mean a Change in Taxes Event, a Regulatory Event and an Insurance Event. Each definition of these terms as proposed by GasNet only covers positive events. It was for this reason that the Commission included a proposed amendment in its Draft Decision to allow for negative pass through amounts.

The Commission maintains its original view that the pass through mechanism proposed by GasNet does not adequately deal with negative pass through amounts that occur in previous years. Further, GasNet provides no evidence as to why pass through events are asymmetric, and even if this were the case, no explanation has been provided as to why the pass through mechanism should not adjust for both increases and decreases in costs. Accordingly, the Commission has specified amendment 3 to allow for negative amounts in the definitions of Change in Taxes Event, Regulatory Event and Insurance Event, and in the pass through mechanism generally.

The Commission considers that a mechanism that accommodates both positive and negative amounts is not counter to the legitimate business interests of GasNet (pursuant to section 2.24(a)). Further, a symmetrical mechanism would result in appropriate and relevant costs impacting on reference tariffs which would be in the interest of users and potential users (section 2.24(f)). In addition, reference tariffs would reflect the economically efficient operation of the pipeline (section 2.24(d)).

The Commission proposed in the Draft Decision that an allowance for deductibles in current insurance policies held by GasNet should be included in the pass through mechanism, rather than in cash flows. The Commission maintains that this approach is reasonable (see section 6.2.4 of this Final Decision).

Amendment 3

GasNet must amend the following in its revised access arrangement:

- the definition of a Change in Taxes Event in clause 9.1 so that (b) reads 'the removal or imposition of a Relevant Tax';
- the definition of a Regulatory Event in clause 9.1 to allow for regulatory requirements that may result in either higher or lower costs for GasNet;
- the definition of an Insurance Event in clause 9.1 to allow for a changes in the Minimum Insurance Level that exceed or fall short of the Benchmark Insurance Costs; and
- the definition of an Insurance Event in clause 9.1 to include the amounts currently identified in the asymmetric risk allowance as deductibles in current insurance.

GasNet must also amend clause 6.4 of its revised access arrangement to allow both positive and negative pass through amounts.

Relevant tax

In its proposed revised access arrangement, GasNet proposed the following definition of a relevant tax:

> Means any tax, rate, duty charge, levy or other like or analogous impost paid or taken to be paid by GasNet associated with the tariffed Transmission Service, but excludes income tax and capital gains tax.

In its Draft Decision the Commission proposed that the definition of a 'relevant tax' be amended based on the wording of the current Tariff Order. GasNet criticised the Commission's proposed changes to the definition of 'relevant tax', and argued that the definition is too restrictive and gave the pass through mechanism no substantive operation.

The Commission notes GasNet's concern. However, as discussed in the Draft Decision, it considers the above definition is too broad and may undermine the incentive based regulatory regime. To find an appropriate balance, the Commission has considered the costs and benefits of excluding certain taxes from the pass through mechanism:

- income tax (or state equivalent income tax) and capital gains tax. These exclusions were proposed by GasNet in its proposed revised access arrangement. The Commission agrees that these should be excluded from the pass through mechanism;
- penalties and interest for late payment relating to any tax, rate duty, charge, levy or analogous impost. These items are within the control of GasNet and should therefore not be subject to pass through. It is not in the interest of users (section 2.24(f)) to incur these additional charges which GasNet is able to avoid entirely;
- fees and charges paid or payable in respect of a Regulatory Event. The Commission considers that the pass through of theses costs may lead to a double counting of pass through amounts which is not appropriate; and

- stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties. As noted by the ESC, an assessment of these costs would require a full price determination exercise. On a cost benefit basis, it would not be in the interest of GasNet (section 2.24(a)) to undergo such an exercise nor in the interest of users (section 224(f)) to allow the pass through of such costs.

In general, the Commission does not consider it appropriate to include the above tax items in the pass through mechanism. It notes that, except in the case of income tax, GasNet has not provided any explanation as to why the exclusion of the identified items would be contrary to its legitimate business interests. It appears to the Commission that the inclusion of many of the items would not be in the interest of users (pursuant to section 2.24(f)). Nor would their inclusion provide reference tariffs that reflect the economically efficient operation of the pipeline (section 2.24(d)).

In addition, the Commission has determined that taxes such as fringe benefits tax, payroll tax, land tax, and municipal rates and taxes are legitimate taxes that would be incurred by a prudent service provider acting efficiently. These costs should be incorporated in the pass through mechanism. Therefore, the Commission concludes that the following amendment is required.

Amendment 4

GasNet must amend the definition of a Relevant Tax in clause 9.1 to read the as follows.

Relevant tax means any tax, (including any rate, duty, charge, levy or other like or analogous impost paid or taken to be paid by GasNet associated with the Tariffed Transmission Service), but excludes:

(1) income tax (or State equivalent tax) and capital gains tax;

(2) penalties and interest for late payment relating to any tax, rate duty, charge, levy or analogous impost;

(3) fees and charges paid or payable in respect of a *Regulatory Event*,

(4) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties; and

(5) any tax, rate, duty, charge, levy or other like or analogous impost which replaces the taxes and charges referred to in (1) to (4).

Assessment period and operation of the pass through mechanism

GasNet is not opposed to the adoption of a 40 business day assessment period for pass through events. The Commission considers that it is in the public interest (pursuant to section 2.24(e) of the Code) to provide a period that allows assessment of the pass through events proposals to be undertaken by the Commission. Accordingly, the Commission maintains that a 40 day assessment period is reasonable.

Since the Draft Decision, the Commission has further considered how the pass through mechanism would operate. It was originally contemplated by clause 6.1 of the proposed revised access arrangement that GasNet may initiate a pass through application at any time provided that a pass through event had occurred or will occur.

As this clause did not require GasNet to notify the Commission of any negative pass through events, the Commission proposed in its Draft Decision an amendment to allow the Commission to initiate a pass through review.

As the pass through mechanism will also be relevant to the assessment of the annual transmission tariff review, it appears administratively prudent for the two matters to be considered at a similar time. For that reason, the Commission has decided that it is more appropriate to introduce an annual pass through assessment where all pass through events (that is, both positive and negative) occurring in the relevant period are evaluated at the one specific time. In discussions with the Commission, GasNet has agreed in principle with this approach.

The collection of these adjustments into one mechanism means that users should only face one tariff change per year. The annual transmission tariff application from GasNet is required (under amendments in this Final Decision) 30 business days prior to the start of a regulatory year for approval by the Commission by 10 business days before the start of the year. In light of the 40 business day assessment period required for pass through events, the Commission has determined that GasNet must submit a statement of pass through events which have occurred in the relevant period (or if no pass through events have occurred, a statement to this effect) at least 50 business days prior to the start of a regulatory year. In the case of the first assessment which will be relevant for the 2004 transmission tariffs, GasNet must only include those pass through events which have occurred since 1 January 2003. For the remainder of the assessments relevant to the 2003-2007 period, GasNet may only include those pass through events which have not been previously notified to the Commission.

Amendment 5

GasNet must amend clause 6.2(b) of its revised access arrangement to provide an assessment period of 40 business days and to allow the Commission, at its absolute discretion, to extend the period by a further 40 day period on one or more occasion where it considers it necessary to adequately assess the pass through proposal. Clause 6.1 of its revised access arrangement should also be amended so that:

- GasNet is obliged to submit a Pass Through Event statement to the Commission at least 50 business days prior to the start of the regulatory year;
- the statement must detail all Pass Through Events which have occurred in that period (ending on the date specified in the statement) but not previously notified to the Commission and provide the information described in 6.1(a) to (e) of the revised access arrangement for those events; and
- where no Pass Through Events have occurred for the relevant period, this should be stated.

The Commission considers that any required pass through adjustment should be recovered (paid back) through the average revenue control or K factor mechanism. The Commission understands that this would require an amendment to be made to the K_{ta} and K_{tb} equations in clauses 4.5, 4.6 and 4.7 of Schedule 4 of GasNet's revised access arrangement. The Commission does not consider that amendments (apart from those outlined in chapter 6 of this Final Decision) should be made to the individual tariff control mechanism in clause 4.8 and 4.9 of Schedule 4 to accommodate pass through changes. This will ensure that individual tariffs will only increase each year by a maximum of CPI-X+2 per cent.

The Commission considers that any pass through amount claimed must have been incurred within the 2003 to 2007 period. As with the average revenue control mechanism, the Commission will allow a carryover into the third access arrangement period for any pass through amounts incurred in the second access arrangement period but not recovered (paid back) in that period.

Amendment 6

GasNet must amend:

- clauses 4.5, 4.6 and 4.7 in Schedule 4 and clauses 6.4 and 6.5 of its revised access arrangement to allow any approved pass through amounts to be recovered (paid back) through the average revenue control mechanism;
- clauses 6.2 and 6.3 to specify that pass through amounts must have been incurred by GasNet in the 2003 to 2007 access arrangement period; and
- schedule 4 to allow for a carryover in the third access arrangement period for any pass through amounts incurred in 2003 to 2007 period but not recovered (paid back) in that period.

The Commission maintains its position that GasNet must provide detailed documentary evidence in support of any pass through statement. Unless demonstrated that the disclosure of the information will be harmful to the legitimate business interests of GasNet, a user or prospective user, the pass through statement and any accompanying information will be considered by the Commission to be public information.

In addition, GasNet must annually (at least 50 business days prior to the start of the regulatory year) provide the Commission with a copy of insurance premium invoices, irrespective of whether a pass through event statement has been submitted in that year.

Amendment 7

GasNet must amend:

- clauses 6.1 and 6.2 of its revised access arrangement to require the provision, at least 50 business days before the start of a regulatory year, of sufficient detailed documentary evidence which substantiates that the aggregate costs facing GasNet have increased or decreased as a consequence of the alleged pass through event.
- clause 6.1 of its revised access arrangement to require GasNet to provide the Commission with a copy of insurance premium invoices annually at least 50 business days before the start a regulatory year, irrespective of whether a pass through event statement is submitted.

The Commission agrees with GasNet that variations resulting from the pass through mechanism are not a revision for the purposes section 2 of the Code.

3.3 Reference tariff methods

Section 8 of the Code sets out the general principles for a reference tariff and certain factors about which the relevant regulator must be satisfied before the regulator may approve reference tariffs and the reference tariff policy. The general principles are contained in sections 8.1 and 8.2 of the Code.

Section 8.3 of the Code states that, subject to requirements of that section and the objectives expressed in section 8.1, the method by which the reference tariff may vary within an access arrangement period through implementation of the reference tariff policy is within the discretion of the service provider. The Code suggests two alternative forms of regulation methodologies (but notes that there may be variations or combinations of these approaches):

- under a price path approach, tariffs are determined before 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; and
- under a cost of service[66] approach, tariffs are adjusted during the access arrangement period in light of actual outcomes (such as sales volumes and actual costs) to ensure that the actual costs of the services are recovered.

GasNet states that tariffs will vary in accordance with a price path approach.[67] However, it has also proposed inclusion of a pass through mechanism to allow it to recover certain potential cost increases during the second access arrangement period which is consistent with a cost of service approach. The Commission considers that the proposed methodology would be most accurately described as a combination of the price path and cost of service approaches. While the Commission has a strong preference for incentive based regulation which would be consistent with a pure price path approach, it recognises that the Code gives service providers discretion in selecting a ‘price path’ or ‘cost of service’ approach, or ‘variations or combinations of these approaches’ (section 8.3 of the Code).

Consideration of the tariff path is provided in section 8.2 of this Final Decision.

Section 8.4 of the Code permits a choice of three methodologies for determining the total revenue which are termed Cost of Service[68], IRR and NPV.

The Cost of Service approach is described as one where the total revenue is set to recover the costs of providing services, with the costs being calculated on the basis of:

- a rate of return on the value of the capital base (the capital assets that form the covered pipeline);
- depreciation of the capital base; and

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66 The Code also uses the capitalised expression ‘Cost of Service’ in section 8.4 to refer to a methodology for determining total revenue.

67 GasNet access arrangement, 27 March 2002, p. 5.

68 The Code also uses the uncapitalised expression ‘cost of service’ in section 8.3(a) to refer to a form of regulation sometimes referred to as rate of return regulation.

- non-capital costs (the operating, maintenance and other non-capital costs incurred in providing all services provided by the covered pipeline).

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).

Under the IRR approach, total revenue is set to provide an internal rate of return (IRR) for the covered pipeline on the basis of forecast costs and sales, subject to the principles set out in sections 8.30 and 8.31 of the Code.

Under the NPV approach, total revenue is set to deliver a net present value (NPV) for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using a discount rate that would yield a return consistent with sections 8.30 and 8.31 of the Code.

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 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 and 8.5A of the Code, provided they can be translated into one of these forms.

GasNet proposes to retain the Cost of Service approach adopted for the initial access arrangement period. The Commission considers this is appropriate. GasNet's proposals are considered in detail in the following sections.

4. Capital base

This chapter deals with GasNet's proposals regarding the roll forward of the initial capital base established in the Commission's 1998 decisions. The Commission's assessment of GasNet's proposals for how the regulatory asset base would be rolled forward for the third access arrangement period is considered in chapter 3 of this Final Decision.

4.1 Roll forward of the capital base

4.1.1 Code requirements

Section 8.9 of the Code states that (for the Cost of Service methodology) the capital base at the commencement of each access arrangement period after the first is determined as:

- the capital base at the start of the preceding access arrangement period; plus
- the new facilities investment (or the recoverable portion) in the preceding access arrangement period (adjusted as relevant as a consequence of section 8.22 to allow for the differences between actual and forecast new facilities investment); less
- depreciation for the preceding access arrangement period; less
- redundant capital identified prior to the start of the new access arrangement period.

4.1.2 Current access arrangement provisions

Fixed principle 3 in clause 9.2 of the current Tariff Order states that in determining price regulation in the subsequent access arrangement period, the regulator is to:

> (3) use the *capital base* for *TPA* at the start of the *initial regulatory period*, adjusted to take account of inflation since 1 January 1998, depreciation, wholly or partially redundant assets and additions and disposals in the ordinary course of business since 1 January 1998.

4.1.3 GasNet proposal

GasNet states that in the 1998 Final Decision, the Commission determined that the initial capital base (ICB) was valued at $363.7 million.[69] This valuation was based on a valuation by Gutteridge, Haskins and Davey Pty Limited (GHD) as at 30 June 1997 from which the value of easements ($40.2 million) and some pipeline regulators and associated remote terminal units ($1.9 million) were removed. In addition, some value from the WTS and Lurgi pipes was deducted to achieve lower tariffs on these assets ($9 million and $1.2 million respectively) and the value of the Murray Valley pipeline ($15.7 million) was omitted. Further, GasNet claims the Commission incorrectly

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69 ACCC, *Final Decision: access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System; access arrangement by Transmission Pipelines Australian Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System; and access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System*, 6 October 1998.

expressed the ICB as $363.7m in the 1998 Final Decision whereas it considers that the amount used to calculate the reference tariffs was $358.0 million.[70] GasNet proposes that the 'correct' capital base as at 1 January 1998 is $399.5 million. This is derived by adding the value of the easements and regulators (adjusted for depreciation and inflation to give a 31 December 1998 value) to the $358.0 million.

Table 4.1 shows adjustments made by GasNet for depreciation, inflation and capital expenditure since 1 January 1998 to give a regulatory asset base (RAB) at 1 January 2003 of $539.7 million.[71]

Table 4.1: Proposed roll-forward of the capital base

	$ million				
Year ending 31 December	**1998**	**1999**	**2000**	**2001**	**2002**
Opening capital base	399.5	431.2	518.1	537.7	542.3
Depreciation allowance	-13.8	-15.2	-17.0	-18.1	-18.3
Capital expenditure	39.0	93.3	6.2	4.5	0.6
Disposals/redundancies	-0.2	-0.2	-1.4	-0.1	-0.03
Inflation	6.6	9.0	31.8	18.4	15.2
Closing capital base	431.2	518.1	537.7	542.3	539.7

Source: GasNet access arrangement information, 27 March 2002, p. 4.

Subsequent to GasNet's lodgement of the proposed revisions to its access arrangements, the Commission has worked with GasNet to verify these figures. Several errors have been identified in the modelling by GasNet which produced the above figures. Consequently, GasNet has provided revised figures which are reproduced in Table 4.2 below.

70 GasNet access arrangement information, 27 March 2002, p. 3; GasNet submission, 27 March 2002 pp. 29-30.

71 GasNet submission, 27 March 2002, p. 5.

Table 4.2: Revised proposed roll-forward of the capital base

Year ending 31 December	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Opening capital base	399.2	430.3	516.9	534.5	537.6
Inflation	6.3	7.8	30.1	16.8	13.6
Depreciation allowance[a]	13.8	15.2	17.0	18.1	18.4
Capital expenditure[a]	38.7	94.1	6.3	4.6	0.7
Disposals/redundancies[a]			1.8	0.2	
Indirect asset allocation					0.5
Closing capital base	430.3	516.9	534.5	537.6	533.8

Source: GasNet Erratum, 19 July 2002.
Note: (a) These items are inflated to give an end of year value.

Indirect assets (such as the corporate headquarters building) are used by both the regulated and unregulated parts of GasNet's activities. Only a proportion of an appropriate return of and on capital should be recovered through the tariffs on reference services. As the nature of GasNet's business changes, so this proportion changes. An adjustment to the asset base needs to be made to reflect the change in the proportion of these assets that are appropriately in the RAB. In the above table, this adjustment is indicated in the line 'indirect asset allocation'.

4.1.4 Submissions to Issues Paper

Interested parties generally raised concerns about GasNet's proposal to reopen the capital base. TXU noted the significant potential impact on tariffs and that the approach is inconsistent with the Code and GasNet's current fixed principles.[72] TXU also stated that including a value for easements would be counter to the policy of the Victorian Government at the time of privatisation and would result in a windfall gain to GasNet at the expense of consumers. ENERGEX does not believe that the Code permits the capital base to be reopened and proposed that GasNet be required to resubmit its proposed revisions on the basis of the approved initial capital base.[73] Pulse stated that the Code does not permit the capital base to be reopened, and that easements should not be included in the asset base because they are not owned by GasNet and are not included in the GPAL definition of a covered pipeline.[74]

Pulse raised a number of further arguments against reopening the asset base, including that it would be inconsistent with the Code's spirit of certainty and consistency, and that, as GasNet purchased the business with parameters such as the capital base value in place, an increased valuation would lead to windfall gains for GasNet at the expense of retailers and consumers.[75]

72 TXU submissions, 3 May 2002, p. 1 and 31 May 2002, pp. 30-32.

73 ENERGEX submission, 9 May 2002, p. 4.

74 Pulse submission, 16 May 2002, p. 2.

75 ibid., p. 3.

Origin stated its understanding was that the Code does not permit reopening of the capital base and queried the argument put to it by GasNet that easements were included in the initial capital base with a value of $0.[76] Origin also questioned whether there had been a fundamental change in conditions that might justify reopening the asset base.

BHP Billiton stated that the Commission accepted the GHD valuation adjusted by changes made by the applicant in 1998. Further, it is of the opinion that the Code does not allow a restatement of the asset base as proposed by GasNet.[77]

In addition, BHP Billiton, Amcor and PaperlinX believed that the GST spike should be removed from the escalation factors used in the calculation of the RAB.[78]

4.1.5 Draft Decision

Initial capital base

The Commission carefully considered the merits of GasNet's proposal to reopen its regulatory asset base and to adjust it upwards by $41.2 million (to a January 1998 value of $399.2 million). The Commission considered that such a revaluation was unwarranted and would not be consistent with regulatory policy objectives. The Commission was satisfied that it correctly interpreted the requirements of the Victorian Code when it approved the proposed valuation of the initial capital base in 1998. It noted that the valuation approved in 1998 was consistent with that proposed by the Victorian Government as owner at the time of the PTS and WTS. The subsequent purchases of these assets were made in the knowledge that the regulatory asset base had already been set.

The Draft Decision stated that in any case, it is the Commission's understanding that it can only adjust the initial capital base in accordance with sections 8.9 and 8.15 to 8.29 of the Code. Consequently it cannot re-determine the initial capital base.[79] In other words, the Commission understands that the Code does not give it the discretion to make such an adjustment once the initial capital base has been established.

The Commission agreed with GasNet that the fixed principle relating to the roll forward of the ICB (see section 4.1.2 above) substantially restates the requirements of the Code.[80] To the extent that they do differ, the Commission is satisfied that the fixed principle does not place any further restriction or demand on it that the Code does not already do. Consequently, the fixed principle does not alter the above conclusion.

GasNet argued that the Code is not rigid or mechanical in its requirements for the calculation of the RAB as the intention of the Code would be to allow for the correction of what it describes as 'manifest errors'.

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76 Origin submission, 17 May 2002, p.6.

77 BHP Billiton submission, 21 June 2002, pp. 24-28.

78 BHP Billiton submission, 21 June 2002, p. 28; Amcor and PaperlinX submission, 24 June 2002, p. 22.

79 The Commission's legal advice on this can be made available to interested parties.

80 GasNet submission, 27 March 2002, p. 22.

Consequently, the Commission carefully examined the relevant aspects of its 1998 decision documents. It found no evidence of the 'errors' to which GasNet refers in relation to the differences between the GHD valuation and the ICB set by the Commission.[81] The Commission gave consideration at that time to these differences, which in large part were proposed by the applicant, and considers that the differences are deliberate and not errors.

Further, legal advice obtained by the Commission indicated that it cannot re-open the initial capital base. GasNet's predecessor had the opportunity at the time to seek review by the Australian Competition Tribunal of the ICB value approved by the Commission in 1998 but did not do so. The Commission was unaware of any disagreement with the approved valuation prior to discussions with GasNet in 2001.

The Draft Decision noted that the 'mechanical' adherence to the capital base already established to which GasNet objects is one of the aspects of the Code that gives certainty to the regulated entity. It was strongly advocated by the pipeline industry. GasNet may consider proposing to NGPAC a change to these Code provisions.

GasNet claimed that its approach (to adjust the capital base at the beginning of the previous access arrangement period) is consistent with section 2.24(a) of the Code which requires the Commission to take into account the legitimate business interests of GasNet. The Commission fails to see how maintaining the asset valuation adopted when approving the access arrangement in any way violates GasNet's legitimate business interests, especially as GasNet purchased the PTS as a going concern after the Commission approved the access arrangement and therefore was in full knowledge of the value of the RAB and the regulatory regime.

In the 1998 Final Decision, the Commission considered $363.7 million to be a fair value for the ICB, subject to two amendments: that actual inflation, rather than forecast, be used (along with the appropriate depreciation) to adjust the 1 July 1997 figures (the valuation date in the GHD report) to 1 January 1998; and that an appropriate proportion of indirect assets be allocated to excluded services.[82] The resulting figure was $358.0 million.[83] GasNet is incorrect to claim that the Commission inaccurately expressed the balance of these assets and is also incorrect to surmise that the $358.0 million represents the June 1997 value of the assets.

The Commission's Draft Decision concluded that the appropriate RAB as at 1 January 1998 (the starting point for the calculation of the RAB at 1 January 2003) is the $358.0 million established in the 1998 Final Approval. The Commission included an amendment to this effect in the Draft Decision.

Roll forward

As noted in 4.1.1 and 4.1.2 above, both the Code and fixed principle 3 require the RAB at the beginning of 2003 to be calculated by adding new facilities investment to, and

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81 ibid., p. 30.

82 Amendments 3.2 and 3.7 in ACCC, 1998 Final Decision, pp. 41 and 84.

83 See TPA access arrangement information, 30 November 1998 (on which the Final Approval of the Commission was based) Table 7, p. 4.

deducting depreciation and redundancies from, (all for the period 1998-2002) the ICB established in the first access arrangement period. The appropriate figures for capital expenditure and redundant assets are established below in sections 4.2 and 4.3 respectively. The correct depreciation figure is the depreciation forecast for 1998-2002 for the initial access arrangement period, restated for actual inflation during the period rather than the forecast inflation. Forecast depreciation is used because this is the amount which GasNet has been able to recover through the reference tariffs for 1998-2002. Any other figure would mean that at the end of the asset's life, total allowed depreciation would be different to the value of the asset. That is, the asset may have been depreciated more or less than its full value, which is not permitted by the Code (section 8.33(d)) and which would be inequitable for users or the service provider.

GasNet calculated the roll forward of the RAB to produce a figure of $539.7 million at the end of 2002. This calculation was made in a detailed model which has been provided confidentially to the Commission. In its assessment of this model the Commission found a number of errors which, in following discussions, GasNet has accepted. Consequently, GasNet provided a revised calculation of the roll forward of the RAB resulting in a proposed figure of $533.8 million at the end of 2002 (see Table 4.2). The Commission considers this figure overstates the value of the RAB at the end of 2002 for the following reasons:

- as noted above, the starting point at the beginning of 1998 (ICB) is overstated with the inappropriate inclusion of new assets;
- depreciation is overstated as it includes the depreciation of the assets GasNet proposed to include in the revised ICB; and
- the disposals figures are incorrect as they include disposals of assets GasNet proposed to include in the revised ICB.

Adjusting GasNet's revised proposal (Table 4.2) for these items mentioned above produces a RAB at the end of 2002 of $493.2 million, as indicated in Table 4.3 below.

Table 4.3: Adjusted roll-forward of the capital base

	$ million				
Year ending 31 December	**1998**	**1999**	**2000**	**2001**	**2002**
Opening capital base	358.0	389.8	476.9	493.4	496.5
Inflation	5.7	7.0	27.7	15.4	12.4
Depreciation allowance[a]	12.5	13.9	15.7	16.7	16.9
Capital expenditure[a]	38.7	94.1	6.3	4.6	0.7
Disposals/redundancies[a]			1.8	0.2	
Indirect asset allocation					0.5
Closing capital base	389.8	476.9	493.4	496.5	493.2

Source: GasNet Erratum 19 July 2002 adjusted by the Commission.
Note: (a) These items are inflated to give an end of year value.
Figures may not add up due to rounding.

The Commission noted in its Draft Decision that GasNet has used the CPI (all groups, weighted average of eight capital cities) in calculating the inflation component. The Commission considered that this is appropriate in order to maintain the real value of GasNet's capital.

4.1.6 Response to Draft Decision

In its submission to the Draft Decision, GasNet accepted that the access arrangement information for the first access arrangement period supports the ICB valuation of $358 million. In response to the Commission's conclusion that it could not revalue the ICB, GasNet claimed that it was not asking for a revaluation but a rectification of omissions.[84]

The EUAA and the Energy Users Coalition of Victoria (EUCV) supported the Commission's view that the RAB should not be reopened.[85] Amcor and PaperlinX reiterated their opposition to any adjustment to the ICB.[86] Amcor and PaperlinX, BHP Billiton and the EUAA also called for the GST spike impact to be removed from the RAB.[87]

4.1.7 Final Decision

GasNet's distinction between revaluation and rectification does not change any of the Commission's analysis in the Draft Decision. As noted at that time, irrespective of the inability of the Commission under the Code to revalue the ICB, the Commission does not consider it appropriate to change the ICB as the 'omissions' were deliberate and not errors. Further to its deliberations in the Draft Decision, the Commission notes that, even if the errors alleged by GasNet occurred and the ICB could be adjusted, it considers that, in the light of Code objectives, it would not be appropriate to exercise such discretion and adjust the ICB. It also notes it would not be in the interest of users and prospective users (pursuant to section 2.24(f) of the Code) for the ICB to be adjusted upwards to now include the claimed omissions. Consequently, the Commission affirms its decision in the Draft Decision that the ICB of $358.0 million approved in the 1998 Final Approval should be the basis of calculating the roll forward of the asset base. The appropriate amendment is below.

Amendment 8

GasNet must calculate the roll forward of the regulatory asset base on the basis of the initial capital base of $358.0 million (at 1 January 1998) which was approved in the 1998 Final Approval.

As noted above, in the Draft Decision the Commission proposed that the RAB at the end of 2002 be $493.2 million. In the 1998 Final Decision, the Commission required

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84 GasNet submission, 20 September 2002, p. 6.

85 EUAA submission, 20 September 2002, p. 3; EUCV submission, 13 September 2002, p. 8.

86 Amcor and PaperlinX submission, 13 September 2002, p. 7.

87 Amcor and PaperlinX submission, 13 September 2002, p. 10; BHP Billiton submission, 13 September 2002, p. 13; EUCV submission, 13 September 2002, p. 8.

that the return on, and depreciation of, indirect assets be allocated to regulated and excluded services (rather than be completely recovered by regulated services).[88] GasNet has proposed to increase the asset base by $0.5 million to recognise that regulated services as a proportion of all services has increased. However, the Commission does not consider that the Code (sections 8.9 and 8.15 to 8.29) allows for an adjustment to the RAB for this reason. Consequently, the Commission considers that the proportion of indirect assets currently in the RAB should remain fixed. If new indirect assets are purchased then the appropriate proportion to enter the capital base will be assessed at the time the proposed revision to the access arrangement to include them is being assessed. This issue has been discussed with GasNet which has indicated its acceptance of the Commission's position.

Amendment 9

GasNet must calculate the roll forward of the regulatory asset base without any adjustment to the proportion of indirect assets included.

The Commission noted in the Draft Decision that GasNet used the CPI in calculating the inflation component and that this was appropriate in order to maintain the real value of GasNet's capital. While it was not made explicit in the Draft Decision discussion, the Commission was aware that the CPI had not been adjusted to remove the GST spike and considers this to be the appropriate CPI measure required to maintain the real value of the asset base (see section 6.5 of this Final Decision for more discussion). The Commission also notes that this approach was adopted by the ESC in its recent decision on the Victorian distribution businesses.[89]

GasNet's modelling includes a forecast inflation of 2.5 per cent for 2002, there being no actual data available at the time the proposed revisions to the access arrangement were submitted. Figures for the first three quarters of 2002 are now available and the Commission expects GasNet's modelling to incorporate these. The adjustment for the final quarter should use the inflation forecast produced from the Fisher equation which is 2.16 per cent per year. Consequently, the appropriate inflation figure for 2002 for use in the roll-forward calculations is 2.8 per cent.[90]

Amendment 10

GasNet must use an inflation rate for 2002 in the calculation of the RAB which is based on the index numbers published by the ABS for the CPI, all groups, weighted average of 8 capital cities and uses an estimate for the fourth quarter based on the Fisher equation estimate of 2.16 per cent per annum.

[88] ACCC, 1998 Final Decision, p. 84.

[89] ESC, *Final Decision: review of gas access arrangements*, October 2002, p. 134.

[90] This is the increase from December 2001 quarter index of 135.4 to September quarter index of 138.5 (ABS, CPI, all groups, weighted average of 8 capital cities) increased by 1.055357 which is the quarterly expression of the annual inflation rate of 2.16% produced by the CAPM (the fourth root of 1.02160).

Adjusting GasNet's revised proposal (Table 4.2) for these items mentioned above produces a RAB at the end of 2002 of $494.2 million, as indicated in Table 4.4 below. However, it should be noted that the value of $494.2 million may be subject to some further adjustment as the result of amendments required by the Commission in this Final Decision.

Table 4.4: Roll-forward of the capital base

Year ending 31 December	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Opening capital base	358.0	389.7	476.8	493.4	496.5
Inflation	5.7	7.0	27.7	15.4	14.1
Depreciation allowance[a]	12.5	13.9	15.7	16.7	17.0
Capital expenditure[a]	38.6	94.1	6.3	4.6	0.6
Disposals/redundancies[a]			1.8	0.2	
Closing capital base	389.7	476.8	493.4	496.5	494.2

Source: GasNet Erratum 19 July 2002 adjusted by the Commission.
Note: (a) These items are inflated to give an end of year value.
Figures may not add up due to rounding.

4.2 New facilities investment

4.2.1 Code requirements

Section 8.16 of the Code allows the capital base to be increased by the actual cost of new facilities investment provided that this amount is not more than would be invested by a prudent service provider acting efficiently (acting in accordance with accepted good industry practice to achieve the lowest sustainable costs of delivering services), and provided one of the following conditions is satisfied:

i. anticipated incremental revenue exceeds the costs incurred (the economic feasibility test); or

ii. the new facility has system-wide benefits that justify a higher tariff for all users (the system-wide benefits test); or

iii. the new facility is necessary to maintain the safety, integrity or contracted capacity of services (the safety, integrity and contracted capacity test).

If the reference tariff policy allows the service provider to undertake new facilities investment which does not pass the requirements of section 8.16, then the portion of any such investment which does pass those requirements can be included in the asset base under 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 requirements in the future (section 8.19).

4.2.2 Current access arrangement provisions

The reference tariff policies in the current access arrangements allow GasNet to undertake new facilities investment which does not pass the requirements of section 8.16. If the investment partially passes the economic feasibility test then the remainder may be included in the speculative investment fund (net of any recovery through a user capital contribution or a surcharge). However, unlike the Code, the reference tariff policies do not allow GasNet to include part of the investment in the capital base under the system-wide benefits test or the safety, integrity and contracted capacity test and the balance in the speculative investment fund. That is, the investment must completely pass either of these tests or not be included in the capital base at all.

4.2.3 GasNet proposal

GasNet states in its proposed revisions to its access arrangements that it has undertaken $199.67 million of capital expenditure in the first access arrangement period but is only seeking to include $143.6 million in the RAB. As noted above, GasNet has refined its modelling since it lodged its proposed revised access arrangement. As a result, it has provided a revised disaggregation of its capital expenditure which differs slightly from that initially proposed. These figures have been reproduced in Table 4.5 below. While GasNet notes expenditure on the Bulla Park and Young compressors, these are not part of the PTS. Accordingly, the costs and revenues associated with these assets are not relevant to GasNet's access arrangement.[91]

Table 4.5: Revised actual capital expenditure, 1998 to 2002

Project description	$ million	
	Actual expenditure	Included in RAB
Gooding compressor automation	2.21	2.21
Brooklyn compressor automation	4.13	4.13
Brooklyn compressor restaging and gas cooler upgrade	1.85	1.85
Southwest Pipeline	82.80	75.50
Interconnect Assets	42.60	40.40
Bulla Park compressor	28.10	
Young compressor	19.56	
Murray Valley Pipeline	15.63	15.63
General maintenance capital expenditure	1.98	1.98
Non-system capital expenditure	1.17	1.17
Total	200.04	142.88

Source: GasNet Erratum, 19 July 2002.
Note: The total of the capital expenditure proposed to be included in the RAB will not equal the total of the expenditure in Table 4.2 as Table 4.2 figures are inflated to end of year values.

91 However, these assets need to be taken into account when allocating indirect costs between regulated and unregulated activities.

Southwest Pipeline

GasNet proposes to include the full cost of the Southwest Pipeline in its capital base through the economic feasibility test (section 8.16(b)(i) of the Code).[92] It states that the Victorian Government contributed $7.3 million of the $82.8 million total construction cost, giving a value for regulatory purposes of $75.5 million.

GasNet considers that this amount has been in a speculative investment fund following the Commission's 29 June 2001 Final Decision under section 2.38(a)(ii) of the Code not to approve GasNet's prior application to roll-in the cost of the Southwest Pipeline under the system-wide benefits test (section 8.16(b)(ii) of the Code).[93] It calculates that this amount will be $106.9 million as at 1 January 2003 after including an allowance for interest calculated on a compounded basis at the risk adjusted rate of return. However, after considering the prudent investment test (section 8.16(a) of the Code) GasNet proposes that the prudent amount to be attributed to the Southwest Pipeline is the original cost escalated to reflect inflation (that is, $85.0 million).

Consistent with GasNet's proposal to include the cost of the Southwest Pipeline through the economic feasibility test it proposes a stand alone (or incremental) tariff for use of those assets.

GasNet also submits that if the Commission concludes that the Southwest Pipeline does not pass the economic feasibility test, it does pass the system-wide benefits test.[94] GasNet identifies two sources of system-wide benefits for the Southwest Pipeline:

- enhanced system security and reliability; and
- enhanced competition.

GasNet further submits that if the Commission concludes that only a portion of the Southwest Pipeline passes each of the economic feasibility test and the system-wide benefits test, the Code allows each of those portions to be aggregated and included in the capital base.[95]

Finally, GasNet submits that if the Commission concludes that the Southwest Pipeline does not pass the economic feasibility test or the system-wide benefits test the Commission could treat the Southwest Pipeline as a new pipeline under section 8.12 of the Code with a separate access arrangement. However, GasNet states that it does not propose that the Southwest Pipeline be subject to a separate access arrangement. Instead, it notes its intention to merge the PTS and WTS access arrangements and suggests that the Southwest Pipeline could also be merged into the access arrangement taking into account its capital base which would have been determined in accordance with sections 8.12 and 8.13 of the Code.

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[92] GasNet submission, 27 March 2002, p. 35.

[93] ibid., schedule 3, p. 17.

[94] ibid., schedule 3, p. 21.

[95] ibid., schedule 3, p. 24.

Murray Valley pipeline

GasNet claimed that the Commission incorrectly omitted its investment in the Murray Valley Pipeline from the initial capital base in its 1998 Final Decision.[96] However, it did not propose that this be corrected in the adjustment it proposed to the ICB. Instead it proposed to recognise it as capital expenditure occurring in 1998, which is what was forecast by GasNet's predecessor when it submitted the access arrangement for approval in 1997. The value of this construction was claimed to be $15.7 million[97] (although GasNet has $15.63 million in the table above).[98]

Interconnect Assets

The Commission has previously approved the inclusion of GasNet's $40.4 million investment in these assets in the PTS capital base.[99] Accordingly, this investment will be included in the capital base from the start of the second access arrangement period.

Other projects

The Commission accepted the proposal by GasNet that forecast investment in the Brooklyn loop be included in the calculation of reference tariffs for the first access arrangement period. This investment has not as yet been undertaken. GasNet proposes that the forecast cost of this investment be included in the calculation of reference tariffs for the second access arrangement period.

4.2.4 Submissions to Issues Paper

A number of parties commented on GasNet's proposals. For example, BHP Billiton submitted that the Commission must test the capital expenditure allowed into the RAB and seek justification for any expenditure which exceeds the 'capex allowed'.[100]

Southwest Pipeline

A number of interested parties did not agree with GasNet's proposal for inclusion of the cost of the Southwest Pipeline in the PTS access arrangement. For example, EnergyAdvice identified the proposal as being a factor which it considered would lead to excessive tariffs and a price shock.[101]

Both BHP Billiton and ENERGEX considered that there is insufficient evidence to support GasNet's proposal. In particular, BHP Billiton requested that GasNet demonstrate that no cross subsidisation will occur. In addition, both parties raised concerns regarding the impact of the K factor adjustment. BHP Billiton noted that if the K factor is applied to the Southwest Pipeline then the tariffs will not retain the effect of stand-alone tariffs. Similarly, ENERGEX considered that the K factor mechanism may result in a transfer of 'redundant capital risk' from GasNet to its

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96 GasNet access arrangement information, 27 March 2002, p. 3 and submission, 27 March 2002, p. 29.

97 GasNet submission, 27 March 2002, pp. 4 and 29.

98 It appears that $15.63 million is the actual cost of the pipeline which began operation in September 1998 and that $15.7 million is that figure escalated to end of year value.

99 ACCC, Final Decision: Interconnect Assets, 28 April 2000.

100 BHP Billiton submission, 21 June 2002, pp. 29 and 44.

101 EnergyAdvice submission, 30 May 2002, p. 8.

customers. As a result, neither BHP Billiton nor ENERGEX supported the inclusion of the Southwest Pipeline in the revised access arrangement.[102]

Origin supported roll-in of the Southwest Pipeline, but considered this would be warranted under the system-wide benefits test (rather than the economic feasibility test). Benefits identified by Origin are that Victorian customers are able to access the UGS (and obtain system security for 1 in 20 winter peak demand days) and that upstream competition is facilitated by providing Otway Basin gas access to the Victorian market.[103]

Amcor and PaperlinX stated that they had no objection to the Southwest Pipeline being included in the PTS access arrangement providing costs and revenues are 'clearly assessed and ring-fenced to ensure there is no cross-subsidisation'.[104] They commented:

> With the decision for Minerva Gas to flow to Adelaide via the recently committed SEAGas Pipeline combined with a review of the Saturn report it would appear that there is little likelihood of significant gas flows from the Otway Basin during the course of this new regulatory period.
>
> The development of the Minerva field has taken more than 5 years to bring into production. It would be surprising, therefore, if the developers of the Geographe and Thylacine fields could bring them into production during the course of the next access arrangement period. This would support the view that SWP is unlikely to deliver "new" gas into the Victorian market in the near term.
>
> Accordingly, our view is that SWP will be a greatly under-utilised resource in the regulatory period under review and the tariff structure would need to reflect this situation.[105]

Amcor and PaperlinX expressed opposition to GasNet's proposal to allocate incremental costs to the Southwest Pipeline as they consider it would be contrary to the cost-reflective principles of the Code and would result in cross subsidisation. They consider that the Southwest Pipeline tariff structure should ensure that all costs associated with the Southwest Pipeline are 'fairly and appropriately allocated including opex, capital expenditure, depreciation, benefit sharing and K-factor carryover'.[106] They note the back-end loaded tariff proposed for the Southwest Pipeline and contend that any losses incurred should be fully identified and carried and only recouped from future usage of the Southwest Pipeline. In addition they are of the view that the claimed effective life of the Southwest Pipeline is significantly over-stated. Further, they consider that the tariff should recognise that gas flows will be bi-directional and that injection and withdrawal tariffs should apply at both ends of the Southwest Pipeline.[107]

ExxonMobil submitted a report by ACG that it commissioned on GasNet's proposal to include the cost of the Southwest Pipeline through the economic feasibility test and

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102 BHP Billiton submission, 17 May 2002, pp. 10-13; ENERGEX submission, 9 May 2002, p. 3.

103 Origin submission, 17 May 2002, p. 2.

104 Amcor and PaperlinX submission, 24 June 2002, p. 9.

105 ibid., p. 10.

106 ibid., p. 10.

107 ibid., p. 14. BHP Billiton also considers that injection and withdrawal tariffs should apply at both Iona and Lara: BHP Billiton submission, 21 June 2002, p. 13.

charge an incremental tariff on the Southwest Pipeline.[108] The report examined whether GasNet's average revenue yield approach is consistent with the intent of the economic feasibility test that assets included through that test should be paid for solely by users of those assets. The report demonstrates how the costs of the Southwest Pipeline could be passed on to other users of the PTS through the tariff control mechanism if it is not modified to quarantine revenue shortfalls on the Southwest Pipeline. The report recommends:

- a separate price control formula to apply to tariffs in respect of the Southwest Pipeline assets, and any K factor in the price control should be quarantined to future Southwest Pipeline tariffs;
- establishment of a redundant capital policy that requires the value associated with the Southwest Pipeline assets to be written down to the extent necessary to permit costs to be borne by Southwest Pipeline users; and
- fixed principles to ensure that the Southwest Pipeline is effectively quarantined in future periods.[109]

Other projects

The Commission did not receive any substantive comments in response to the Issues Paper regarding the Murray Valley pipeline, the Interconnect Assets or the other capital expenditures that had arisen during the first access arrangement period.

4.2.5 Draft Decision

Interpretation of relevant Code provisions

The Draft Decision noted that the Code's economic feasibility test would be satisfied if the total PTS incremental revenue expected to be achieved from use of a new asset at least covers the costs associated with that asset. The Commission noted GasNet's contention that this test would be satisfied if only the gross incremental revenue expected to be generated from use of a new asset were to be considered (that is, without netting off any reduced revenue from use of other parts of the PTS which ensues from the use of the new asset). However, in interpreting this test the Commission considers that it must be satisfied that an investment would be viable without funding from the use of other parts of the PTS. In other words, the net increase in PTS revenues as a result of a new asset would need to at least match its cost. Accordingly, the Commission assessed the cost of GasNet's new facilities investments against the associated net increase in revenues that would be reasonably expected to be generated on the PTS.

The Draft Decision noted that the application of the Code's prudent investment test was discussed in its consideration of GasNet's 2000 proposal to roll-in the cost of the Southwest Pipeline.[110] It concluded that this investment appeared to be prudent in a technical and engineering sense as it is sized appropriately to match the UGS facility

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[108] ACG, *Implementation of incremental pricing of the Southwest Pipeline*, June 2002 (ExxonMobil submission, 5 June 2002).

[109] ibid., pp. 23-25.

[110] ACCC, Final Decision: Southwest Pipeline, 29 June 2001, pp. 31-37.

and its unit costs accord with relevant benchmarks. This is an important consideration when applying section 8.16(i) of the Code but does not in itself establish that an investment would ‘achieve the lowest sustainable cost of delivering Services’.

For GasNet’s access arrangement for the PTS, services are defined as those being provided by GasNet’s transmission pipelines. GasNet’s investment in the Southwest Pipeline increased the effective capacity of the PTS, allowing it to provide a greater quantity of the tariffed transmission service. More specifically, it provided additional capacity (and quantity of services) by means of a link between Lara and the Otway Basin.

The Commission noted that one of GasNet’s predecessors calculated that similar additional system deliverability could have been achieved by instead looping the remainder of the Longford to Pakenham pipeline (including a minor upgrade of the Gooding compressor) for about two thirds of the cost of the Southwest Pipeline.[111] While this investment would have provided additional system deliverability it would not have provided a link with the Otway Basin and the UGS facility. Therefore, whether GasNet’s investment in the Southwest Pipeline would achieve the lowest sustainable cost of delivering services will depend on whether the relevant services are associated with additional system deliverability in general or specifically with the services provided by the Southwest Pipeline.

Southwest Pipeline

Prudent investment test

The Draft Decision noted that the Commission previously considered a proposal by GasNet to include the Southwest Pipeline in the PTS capital base by applying the system-wide benefits test.[112] At that time the Commission concluded that the Southwest Pipeline does provide system-wide benefits in the form of system security and competition benefits but there was insufficient evidence to justify a commensurately higher tariff for all users. GasNet’s access arrangement did not allow partial inclusion of an investment under this test. Consequently, it recommended that GasNet reapply as part of the current review when there would be a longer operational history, enabling it to make a better informed assessment. The Commission commented that GasNet could submit revisions to remove unnecessary constraints in its access arrangement. It also expressed reservations about compliance of the roll-in proposal with reference tariff principles and the Code’s prudency requirements.

In assessing GasNet’s investment in the Southwest Pipeline under the prudent investment test the Commission concluded in its Draft Decision that the relevant services include additional supply capacity and the connection with Iona. These services are discussed below. The Commission’s assessment was that GasNet’s proposed valuation of the Southwest Pipeline represents a prudent investment.

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[111] ibid., p. 30.

[112] ibid.

Economic feasibility test

The Draft decision stated that the Code's economic feasibility test would be satisfied if incremental revenue on the PTS expected to be achieved from use of the Southwest Pipeline at least covered its costs. In interpreting this test the Commission must be satisfied that the Southwest Pipeline would be viable without funding from the use of other parts of the PTS. However, GasNet has not taken into account in its application the expected loss of revenue on the Longford to Pakenham pipeline compared to that which would have been achieved in the absence of the Southwest Pipeline. Accordingly, its estimate of the incremental revenue generated by the Southwest Pipeline is overstated. Adjustment for this factor results in a correspondingly higher reference tariff for the Southwest Pipeline.

The Commission's Draft Decision proposed an amendment to GasNet's flow assumptions to recognise the likelihood that gas from the Yolla field will be injected into the PTS. These flows would be expected to displace potential flows on the Southwest Pipeline. Adjustment for this factor would result in a further increase in the reference tariff required for the Southwest Pipeline.

The economic feasibility test assessment relies on the willingness of users to pay the stand-alone Southwest Pipeline tariff and the likely level of demand at that tariff (as the associated costs are known with considerable certainty). The Commission noted the doubts expressed by some parties about the sustainability of the demand forecasts at the tariff level proposed by GasNet. Once allowances are made for lower revenues on the Longford to Pakenham pipeline and demand displaced as a result of injections from the Yolla field, the level of the reference tariff required for the Southwest Pipeline increases substantially. The Commission stated that it does not consider that the Southwest Pipeline would be able to sustain the tariffs and flows that would be required to generate sufficient incremental revenue to cover its costs.

The Commission considered GasNet's argument that it should accept inclusion of the cost of the Southwest Pipeline under the economic feasibility test and not be concerned about the demand forecasts as a service provider would generally be expected to bear the costs of any consequent revenue shortfalls. However, as interested parties noted, under GasNet's first proposal, the cost of any demand shortfalls could potentially be shifted to customers using other parts of the PTS through the revised K factor mechanism. These parties are concerned that, as a result, the rationale for the Code's economic feasibility test would be defeated. They consider that this anomaly could be remedied through an amendment to the K factor adjustment such that any shortfalls in Southwest Pipeline revenues could be quarantined. The Commission noted that the anomaly would only be properly remedied if, at future revisions of the access arrangement, the Southwest Pipeline was quarantined from the cost allocation model as it has been in the current proposal. The Commission was also of the view that it would be inappropriate to include an asset in the asset base on the grounds that it would generate sufficient revenue to pay for itself if it were likely that the rationale for this test could be defeated through mechanisms which could permit its costs to be recovered from users of existing assets.

As the Commission concluded in the Draft Decision that GasNet's investment in the Southwest Pipeline would not satisfy the first test proposed by GasNet, it also considered GasNet's alternative proposals.

System-wide benefits test

The Commission's June 2001 Southwest Pipeline Final Decision provided a detailed assessment of GasNet's earlier proposal to include the full cost of this facility in its capital base under the system-wide benefits test. That assessment included a careful examination of a cost-benefit analysis provided by GasNet regarding these assets. The Commission considered that this assessment remained relevant for the Draft Decision. While it also took subsequent evidence into account, it stated that it was unnecessary to repeat the earlier analysis. Accordingly, the Commission noted that its analysis in the June 2001 Southwest Pipeline Final Decision was to be considered in conjunction with the Draft Decision.

The Commission's Draft Decision stated that it remained of the view expressed in June 2001 that the facility gives rise to system-wide benefits in the form of system security benefits and competition benefits. Subsequent usage of the Southwest Pipeline confirms its importance as a source of these benefits. For example, the Southwest Pipeline played an important role in the maintenance of adequate gas pressures during the level 5 gas emergency on 22 July 2002.[113] As demand grows, the Southwest Pipeline can be expected to provide increasing benefits in this regard. Further, the Charles River Associates report notes the critical role that the Southwest Pipeline would play in response to a multiple event.[114]

The Commission stated in the Draft Decision that it was not persuaded to change its view that there is inadequate evidence that system-wide benefits would justify an increase in reference tariff for all users sufficient to recover the full costs of the investment. However, it did note that it considers these benefits are substantial.

Economic feasibility and system-wide benefits

The Commission's Draft Decision proposed to approve the removal of current restrictions in GasNet's extensions and expansions policy that prevent inclusion of an investment under a combination of the section 8.16(b) tests (see section 11.3.5 of the Draft Decision). Further, it considered it appropriate to assess GasNet's investments under the revised extensions and expansions policy. The Commission also considered that it may apply the provision of section 8.9 of the Code at the start of a new access arrangement period.

Consequently, the Commission considered that it could now accept the inclusion of some or all of the cost of an asset in the capital base through a combination of the section 8.16(b) provisions. As noted, this was not possible in June 2001 because of limitations imposed by GasNet's extensions and expansions policy. In addition, any residual part of a prudent investment beyond amounts that could be included in the

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[113] VENCorp, *Market and Systems Operations Report, 3 and 22 July 2002*, 9 September 2002.

[114] Charles River Associates, *Victorian gas systems security cost benefit risk analysis*, March 2002, p. 5.

capital base under these provisions could be included in a speculative investment fund. Pursuant to section 8.19 of the Code, this residual may subsequently be added to the capital base if at any time the type and volume of services provided by the investment change such that they satisfy the requirements of section 8.16. In applying these provisions the Commission was careful to ensure that there was no double counting of the contributions of the Southwest Pipeline.

The Commission considered in the Draft Decision that it was appropriate to assess the contribution of the Southwest Pipeline in terms of both the net additional revenue and the system-wide benefits it would generate. It acknowledged that both contributions are difficult to quantify with any certainty.

The likely incremental revenue from the Southwest Pipeline is dependent on the tariffs which users will be willing to pay. GasNet has proposed tariffs for the Southwest Pipeline based on a normalised revenue over 20 years and a normalised tariff over five years. This results in a higher initial tariff than if the tariff was normalised over 20 years. A lower initial tariff would reduce the disincentive to using the Southwest Pipeline.

The Commission agreed with interested parties that the tariff proposed for the Southwest Pipeline appeared to be unsustainable. It considered, however, that it is reasonable that charges for usage of the Southwest Pipeline would need to reflect the higher costs of providing services through this facility. At the same time, tariffs would need to be consistent with users' willingness to pay for use of the Southwest Pipeline.

The Commission concluded in its Draft Decision that users would be willing to pay a premium of approximately 10 per cent to use the Southwest Pipeline (compared to the Longford to Pakenham pipeline) without prejudicing GasNet's demand forecasts (after allowance is made for projected gas flows from the Yolla field). It proposed to accept a tariff differential of approximately 10 per cent for the purposes of the economic feasibility test. The Commission noted that a Southwest Pipeline tariff of approximately $2.00/GJ implies that only about half its cost would be able to be recovered under the economic feasibility test.

The Draft Decision commented that the Commission considered the application of the system-wide benefits test in its final decisions with respect to GasNet's Interconnect Assets and Southwest Pipeline revisions proposals. It determined that the competition and system security benefits associated with the Interconnect Assets justified an addition of $40.4 million to GasNet's capital base in 2000 but the benefits associated with the Southwest Pipeline were less than its full cost.

In applying this test, the Commission was mindful that system security and competition benefits are likely to exhibit diminishing returns. Against this, the Southwest Pipeline would be reasonably expected to provide substantially greater security benefits than the Interconnect Assets and that new gas field developments in the Otway Basin indicate a substantial potential for additional supply competition. Importantly, gas flow projections accepted in the Draft Decision suggested that the Southwest Pipeline would facilitate a much larger increase in supply competition.

On balance, the Commission concluded in its Draft Decision that the system-wide benefits available from the Southwest Pipeline would be broadly commensurate with those provided by the Interconnect Assets. Furthermore, the combined contributions under the two tests cover the full costs proposed by GasNet for its investment in the Southwest Pipeline.

Conclusion

Following the above discussion in the Draft Decision, the Commission proposed to accept the inclusion of the Southwest Pipeline in the PTS capital base under a combination of the Code's economic feasibility test and system-wide benefits test. Consistent with its views regarding the sustainability of charges on the Southwest Pipeline, it proposed that tariffs for the Southwest Pipeline should be approximately 10 per cent higher than those on the Longford to Pakenham Pipeline and that they should be calculated on the basis of full levelisation over 20 years. Accordingly, the Commission proposed an appropriate amendment.

The Commission noted in the Draft Decision that the Southwest Pipeline is not a new pipeline for the purposes of the Code and cannot be treated as one.

The Commission did not propose to quarantine GasNet's investment in the Southwest Pipeline as suggested by a number of interested parties. This matter was discussed in section 6.2.2 of the Draft Decision.

Murray Valley Pipeline

In its Draft Decision the Commission observed that GasNet had offered no argument in its submission as to why it considered expenditure for the Murray Valley Pipeline should be included in the PTS capital base without consideration of section 8.16 of the Code. GasNet's approach appeared to rely on the wording of section 8.9(b) which refers to inclusion of new facilities investment in the immediately preceding access arrangement period. GasNet appeared to contend that the Commission should include this investment in the value of the initial capital base and that it be rolled forward pursuant to section 8.9(a). The Commission acknowledged that the Murray Valley Pipeline commenced operation prior to the PTS access arrangement coming into effect in March 1999. However, the provisions of the Code do not allow it the discretion to redetermine the value of the initial capital base. Accordingly, this investment could not be rolled forward under section 8.9(a).

The Commission was cognisant of the objective set out in section 8.1(a) that a service provider should be allowed the opportunity to recover the efficient costs of an investment. It considered that this fundamental objective would not be achieved if the investment was precluded from inclusion in the PTS asset base.

The Commission requested from GasNet information which would support its inclusion. GasNet supplied some information but it was received by the Commission too late for it to be assessed and discussed in the Draft Decision. The Commission indicated that its analysis would appear in the Final Decision.

Interconnect Assets

The Draft Decision noted that, as the Commission has previously approved the roll-in of GasNet's investment in these assets,[115] GasNet's investment will be reflected in the revised capital base as at 31 December 2002.

Other projects

Apart from the capital expenditure on the Murray Valley Pipeline, the Interconnect Assets and the Southwest Pipeline discussed above, other capital expenditure during 1998-2002 was minor in nature, totalling approximately $11 million. The majority was in relation to compressor automation and restaging.

GasNet has argued that the automation of the Gooding and Brooklyn compressors ($7 million) was necessary to maintain the safety and integrity of the system.[116] Submissions did not address this issue. The Commission has no evidence to suggest that this project was not prudent. Consequently, the Draft Decision proposed not to object to the inclusion of these costs in the capital base.

GasNet argues that the Brooklyn compressor restaging and cooler upgrade ($1.8 million) was essential to provide the higher flows and pressures for summer injections of gas into the UGS.[117] It does not nominate which of the section 8.16 tests this project meets. It could be argued that as it facilitates the use of the UGS that the question is whether this project passes the economic feasibility test and that the test would involve assessing the increased revenues from the use of the UGS. Thus, this expenditure would need to be taken into account in the analysis of the Southwest Pipeline. Similar to the assessment of the Southwest Pipeline, it could also be argued that facilitating the use of the UGS provides a system-wide benefit. Given that part of the Southwest Pipeline passes the system-wide benefits test, and the relatively small size of this expenditure, the Commission proposed to add the Brooklyn compressor restaging and cooler upgrade to the RAB under the system-wide benefits test. The Commission stated that it had no evidence to suggest that this expenditure is not prudent.

The remaining $3 million of capital expenditure was mainly for maintenance purposes. GasNet makes no comment on its inclusion in the RAB nor is this expenditure addressed in submissions from interested parties. The Commission has no evidence to suggest that this expenditure was not prudent and considers maintenance of the system to be significantly linked to the safety of the system. Consequently, the Commission proposes to accept the inclusion of this capital expenditure in the RAB under section 8.16(b)(iii) of the Code.

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115 ACCC, Final Decision: Interconnect Assets, 28 April 2000, p. 60.

116 GasNet submission, 27 March 2002, p. 42.

117 ibid., p. 42.

4.2.6 Response to Draft Decision

Southwest Pipeline

A number of parties commented on the Commission's proposal to approve the inclusion of the full cost of the Southwest Pipeline in GasNet's RAB, partly under the economic feasibility test and partly under the system-wide benefits test. Both of the Gippsland Basin producers, two end-users representative groups and a major end-user expressed disappointment that the Commission had proposed to accept roll-in.[118] Concerns raised included:

- that costs of the Southwest Pipeline could be spread to other customers of the PTS through the K factor adjustment;
- that investment in the Southwest Pipeline might not be the best means to achieve the claimed benefits; and
- whether the Code permits an investment to be partly included through each of the two tests, and if it does, whether sufficient benefits are generated in total.

In contrast, Origin and Santos agreed with the proposal.[119] Origin also commented on the possibility of GasNet being over compensated for its investment in the Southwest Pipeline because of the terms of the Transmission Entitlement Deed under which the three foundation retailers currently contract with GasNet to flow gas on the Southwest Pipeline. Santos considered it may be more appropriate for the full cost to be included under the system-wide benefits test and that injection charges at Iona and Longford should be the same. It commented that:

- the Southwest Pipeline and the Interconnect would provide similar quantities of gas in the event of a major failure of supply from Gippsland;
- the Southwest Pipeline can deliver five times the peak rate of the Interconnect at less than double its capital cost; and
- the Southwest Pipeline 'clearly delivers more benefit' than the Interconnect in 'the much more likely scenario of normal peak day demand or a short-term failure of supply from Gippsland'.[120]

GasNet also agreed with the proposal in the Draft Decision. It commented that it is unlikely that the full costs of its investment could be recovered under the economic feasibility test once the likelihood of gas being injected into its system from the Yolla field is taken into account. However, it maintained its position that sufficient system security and competition benefits would be generated to justify its inclusion under the system-wide benefits test.[121] GasNet stated that it would prefer to levelise the whole

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118 See ExxonMobil submission, 10 September 2002, pp. 1-2; BHP Billiton submissions, 13 September 2002, pp. 8-11 and 11 October 2002, pp. 12-20; EUCV submissions, 13 September 2002, pp. 9-11 and 9 October 2002, pp. 7-12; Amcor and PaperlinX submission, 13 September 2002, pp. 7-9; EUAA submission, 20 September 2002, pp. 3-4.

119 Origin submission, 18 September 2002, pp. 1, 3; Santos submission, 20 September 2002, pp. 2, 4-5.

120 Santos submission, 20 September 2002, p. 4.

121 GasNet submission, 20 September 2002, pp. 6-7.

revenue requirement for the Southwest Pipeline rather than to adopt the tariff levelisation approach proposed in the Draft Decision.

Murray Valley Pipeline

In the revisions to the access arrangement, GasNet proposed a tariff for Murray Valley Pipeline users based on the general cost allocation model described in section 8.1 of the Draft Decision. At this tariff, it claimed, the incremental revenues are greater than the incremental costs of the pipeline and therefore the pipeline passes the economic feasibility test and can be rolled into the RAB. In its submission to the Draft Decision, GasNet proposed to set the Tariff D withdrawal tariff lower than the figure produced by the cost allocation model – in fact at a level which would just pass the economic feasibility test. It did not indicate what this level is.[122] More recently GasNet has proposed to calculate a tariff for the Murray Valley Pipeline based on the incremental costs associated with the pipeline (it claims that the full cost of the pipeline will pass the economic feasibility test of the Code 8.16(b)(i)). As well as this incremental tariff, Murray Valley users will pay a tariff for use of the PTS to the entrance of the Murray Valley at Chiltern Valley. This tariff would be calculated using the standard cost allocation methodology which would include a fair share of joint costs.[123]

Amcor and PaperlinX noted that GasNet had not provided any quantified data on the Murray Valley Pipeline and therefore concluded that it does not meet the Code's economic feasibility test.[124] BHP Billiton also noted its inability to assess whether the Murray Valley Pipeline passes the economic feasibility test due to the lack of quantified data.[125]

Other projects

Amcor and PaperlinX state the Commission has not required GasNet to justify increases in past capital expenditure above the amounts approved in the 1998 Final Decision and that the Commission must verify that the new amounts still comply with the cost benefit target anticipated at the time of approval.[126] The EUCV also suggested that only capital expenditure budgeted for first access arrangement period should be included in the RAB or an amount that passes the prudency and efficiency tests of the Code.[127] BHP Billiton claimed that the Commission accepts over-runs on the approved capital expenditure without any cost/benefit analysis.[128]

GasNet agreed with the Commission that it is appropriate to roll-in the costs of the Brooklyn compressor and restaging cooler upgrade on the basis that facilitating the use of the UGS provides a system-wide benefit.[129]

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122 ibid., p. 8.

123 GasNet, Murray Valley Tariff – Revised Proposal, 24 October 2002, p. 1.

124 Amcor and PaperlinX submission, 10 October 2002, p. 2.

125 BHP Billiton submission, 11 October 2002, p. 21.

126 Amcor and PaperlinX submission, 13 September 2002, p. 9.

127 EUCV submission, 13 September 2002, p. 8.

128 BHP Billiton submission, 13 September 2002, p. 12.

129 GasNet submission, 20 September 2002, p. 8.

The Commission did not receive any comments from interested parties or GasNet in response to the Draft Decision regarding the Interconnect Assets.

4.2.7 Final Decision

Interpretation of relevant Code provisions

Some interested parties have suggested that the Commission should require GasNet to justify any increase in its capital expenditure over that which was approved as part of the 1998 Final Decision. However, this suggestion indicates a lack of understanding of the processes involved. In 1998 the Commission approved the access arrangements, which included tariffs which were based on benchmark revenues which included certain forecast capital expenditure. The Commission allowed the inclusion of the capital expenditure (under section 8.20 of the Code) because it considered that the capital expenditure could reasonably be expected to pass the requirements of section 8.16 of the Code. However, the inclusion of this capital expenditure in the revenue model did not mean that it was also included in the RAB, this can only be done after the expenditure has occurred. This action did not bind the Commission to find that, should the capital expenditure occur, that it would pass the requirements of section 8.16. Neither did it constitute an 'approval' of that capital expenditure, for which any exceeding of the quantum would need to be justified. What the Code requires is that the section 8.16 test is applied to all actual capital expenditure which is to be included in the RAB. This is what the Commission has done, as explained in the Draft Decision. The test is applied to the work actually done for the costs actually incurred. It is not relevant what work was forecast to be undertaken and how much it was forecast to cost.

Southwest Pipeline

The Draft Decision noted that the Commission's consideration of GasNet's 2000 proposal to roll-in the cost of the Southwest Pipeline had examined whether GasNet's investment in the Southwest Pipeline was the best means to achieve the claimed benefits. The Draft Decision referred to an earlier calculation that similar additional system deliverability could have been achieved by looping the remainder of the Longford to Pakenham pipeline (including a minor upgrade of the Gooding compressor) for about two thirds of the cost of the Southwest Pipeline. However, this investment would not have provided a link with the Otway Basin and the UGS facility.[130] Accordingly, whether GasNet's investment in the Southwest Pipeline would achieve the lowest sustainable cost of delivering services will depend on whether the relevant services are associated with additional system deliverability in general or specifically with the services provided by the Southwest Pipeline.

The Commission considers that the specific services associated with the Southwest Pipeline do contribute system-wide benefits to the PTS. The Commission remains of the opinion expressed in the Draft Decision that the valuation of the Southwest Pipeline ($85 million at end 2002) represents a prudent investment.

A number of parties contend that the Code does not allow an investment to be included through more than one of the tests in section 8.16(b) of the Code. For example, Amcor

130 Conversely, the Southwest Pipeline does not provide additional capacity from Longford.

and PaperlinX stated that the word ‘or’ is used before each option and that the word ‘one’ in section 8.16(b) denotes mutual exclusion between the options and does not allow aggregation.

The Commission understands that inclusion of the word ‘one’ and the use of the words ‘or’ between each of the options in 8.16(b) is a common drafting technique used (in this case) to indicate that it is not necessary to satisfy all of the factors in 8.16(b). Provided at least one factor is met, the condition in 8.16(b) is satisfied. It does not preclude an interpretation that recovery may be possible for that part of the new facilities investment that meets one or more of the criteria in 8.16(b). The contrary interpretation could preclude a service provider from recovering its legitimate investment. This would be contrary to the principles in section 8.1(a) and 2.24(a) of the Code.

The Commission remains of the opinion expressed in the Draft Decision that it can accept the inclusion in the capital base of some or all of the cost of an asset through a combination of the section 8.16(b) provisions. This is possible for the current assessment of the Southwest Pipeline as a consequence of the Commission’s considerations being in the context of its acceptance of the proposed revised extensions and expansions policy (see chapter 11 of this Final Decision). The Commission also considers that it may apply the provisions of section 8.9 of the Code at the start of a new access arrangement period.

The Commission stated in its Draft Decision that it expected that GasNet’s investment in the Southwest Pipeline could be recovered through a combination of the economic feasibility and system-wide benefits tests. However, it noted that both tests can be difficult to apply with certainty. It considered an earlier quantification of system-wide benefits tests provided by GasNet which it found to be excessive. The Commission did not provide its own quantification of the system-wide benefits likely to accrue either in the 2001 Southwest Pipeline Final Decision or the Draft Decision. It inferred in the Draft Decision that approximately half the investment in the Southwest Pipeline could be recovered under each of the economic feasibility and system-wide benefits tests. This provided GasNet with the opportunity to propose precise amounts once the overall revenue requirements were determined.

The Commission has assessed a quantification submitted by BHP Billiton of the system-wide benefits it considers accrue to the Southwest Pipeline.[131] BHP Billiton suggested that:

- system security benefits would amount to no more than $620 000 a year; and
- no competition benefits are generated.

The Commission’s assessment is that BHP Billiton’s quantification substantially understates the benefits accruing from the Southwest Pipeline. For example, probabilities adopted by BHP Billiton in its calculation of system security benefits appear to result in understatement by at least an order of magnitude. In addition, while competition benefits may be difficult to quantify, the Commission concluded in its Southwest Pipeline Final Decision that some competition benefits do arise though the

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131 BHP Billiton submission, 11 October 2002, pp. 12-19.

extent of those benefits at the time was considered to be uncertain.[132] Having considered subsequent supply developments in Victoria (particularly in the Otway Basin) and further evidence of the operation of the UGS, the Commission considers that these benefits are likely to be substantial. Nonetheless, the Commission does not accept the view that system-wide benefits are sufficient to justify the roll-in of the full investment in the Southwest Pipeline.[133] The Commission considers that the actual benefit of the Southwest Pipeline lies between the two estimates.

As noted in the Draft Decision, system-wide benefits accruing from the Southwest Pipeline are expected to be at least commensurate with those generated by the Interconnect Assets for which the Commission approved roll-in of GasNet's $40.4 million investment in 2000. In real terms, this is about half GasNet's investment in the Southwest Pipeline. Consequently, the Commission has determined that an amount of $42.5 million can be recovered by GasNet through the system-wide benefits test.

As noted in the Draft Decision, the Commission considers that projected volumes on the Southwest Pipeline are sustainable if the tariff is no more than approximately 10 per cent higher than that applying on the Longford to Pakenham pipeline. The Commission has concluded that this is a reasonable assumption. Tariffs of this magnitude are consistent with recovery under the economic feasibility test of $42.5 million. This assessment takes into account GasNet's preference for normalisation of revenues (rather than tariffs) for the Southwest Pipeline. The Commission considers that this approach is reasonable.

Consequently, as indicated in its Draft Decision, the Commission considers that GasNet's full investment of $85.0 million in the Southwest Pipeline could be included in its RAB with equal portions being included under the economic feasibility and system-wide benefits tests. The Southwest Pipeline tariff (recovering the incremental costs associated with that half of the asset included under the economic feasibility test) would be approximately 10 per cent higher than the tariff for the Longford to Pakenham pipeline.

The Commission considered a range of possible tariff structures for recovering new facilities investment included in the RAB through the system-wide benefits test as part of its Interconnect Assets Final Decision.[134] The approach proposed at the time was that there would be an equal dollar increase in the anytime charge such that all users would pay the same dollar amount extra for each unit of gas transported. The approach implies that benefits generated by the investment are directly linked to the quantity of gas transported. The Commission considers that this approach would also be appropriate for the Southwest Pipeline. It is consistent with the reference tariff principles (section 8 of the Code) and with the current tariff structure (in terms of recovery of the investment in the Interconnect Assets). The Commission considers that it would be consistent with GasNet's legitimate business interests (section 2.24(a)), the

[132] ACCC, Final Decision: Southwest Pipeline, 29 June 2001, pp. pp. 52-54.

[133] See for example, Santos submission, 20 September 2002, p. 5.

[134] ACCC, Final Decision: Interconnect Assets, 28 April 2000, pp. 49-51.

economically efficient operation of the PTS (section 2.24(d)) and the interests of users and prospective users (section 2.24(f)).

Consequently, the Commission has concluded that GasNet's investment of $85.0 million is prudent and may be included in the RAB using both the economic feasibility test and the system-wide benefits test. No part of the investment would need to be placed in a speculative investment fund.

Amendment 11

GasNet must amend Schedule 1 if its revised access arrangement to include tariffs for the Southwest Pipeline which are approximately 10 per cent higher than those on the Longford to Pakenham Pipeline, consistent with $42.5 million being recovered under each of the economic feasibility and system-wide benefits tests. An incremental tariff is to apply on the Southwest Pipeline. Recovery of costs included under the system-wide benefits test is to be by an equal dollar increase in the withdrawal tariffs.

The Commission's assessment of concerns that the costs of the Southwest Pipeline could be spread to other customers of the PTS through the K factor adjustment is provided in section 6.2.2 of this Final Decision. The Commission has specified an amendment to isolate that part of the investment which is being included through the economic feasibility test. The Commission expects that this part of the investment will also be isolated from the rest of the system in the calculation of tariffs at the next scheduled revision.

Murray Valley Pipeline

GasNet suggested that $20 000/inch/km in 1998 dollars is an appropriate benchmark for the capital costs of the pipeline. The Commission considers this to be a reasonable benchmark. It produces a benchmark value of $16 million for the project to which the actual expenditure of $15.63 million compares favourably. The Commission has also considered other aspects of the pipeline, such as its sizing, and has no evidence to suggest that the amount exceeds that which would be invested by a prudent service provider acting efficiently (section 8.16(a) of the Code).[135]

The Commission's approach to the economic feasibility test is to assess the project over its life. It considers that the test is meant to be applied to the facility as a whole. This requires a forecast of volumes over the life of the project, sustainable at the proposed tariff, as well as a forecast of costs. If the NPV of the incremental revenue (revenue less non-capital costs) is greater than the cost of the investment then the project passes the test. An appropriate assumption that could be used in this analysis is that tariffs would be constant in real terms, although this could be relaxed if, for example, lower initial tariffs were desired to stimulate volume growth.

GasNet has proposed an alternative approach in this instance to avoid the difficulty that tariffs after the current period are not known.[136] It proposes a test where the NPV of net

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[135] GasNet, Murray Valley Tariff – Revised Proposal, 24 October 2002, p. 2.

[136] However, GasNet did apply a whole of project life approach in assessing the Southwest Pipeline in the light of the economic feasibility test.

revenues over the next access arrangement period should not be less than the NPV of the capital costs allocated to the period. Its argument is that any costs unrecovered in the next access arrangement period (that is, capital not yet depreciated) will need to be recovered by the project alone in the future because it is quarantined from the rest of the regulated assets. It also considers that the economic feasibility test is ‘forward looking’ and should be performed from the date of the proposed roll-in. For this test, GasNet has assumed the same volumes as it proposed in the tariff model of the revised access arrangement and it has assumed depreciation to be constant in real terms.

Under the reasonable assumption that volumes after the next access arrangement period will not decrease, it can be expected that tariffs will decrease in real terms over successive access arrangement periods under GasNet’s approach (as the capital base is depreciated). Thus, GasNet’s argument appears to be that unit costs in the next access arrangement period are greater (in real terms) than they will be in future access arrangement periods. If the proposed tariffs for the next period will recover the costs in that period then continuing to charge those tariffs (in real terms) over the future access arrangement periods would result in an over-recovery of costs. Therefore, accepting the claim that the forecast volumes are sustainable at the proposed tariffs, the pipeline will produce a future incremental revenue with an NPV greater than the cost of the investment.

The Commission does not accept GasNet’s approach to conducting the economic feasibility test. As noted above, it considers that the test is appropriately applied to the complete asset: the appropriate starting point for the analysis is the date the asset began to earn income and the test should be on the project over its whole life. The Commission has modelled the Murray Valley pipeline over a life of 36 years[137] using information contained in GasNet’s model and using conservative assumptions for data not supplied by GasNet.[138] This model indicates that the Murray Valley pipeline can reasonably be anticipated to generate incremental revenue greater than its initial cost. Thus the Commission considers it appropriate to include the Murray Valley pipeline in the RAB under section 8.16(b)(i) of the Code. It should be included in the capital base at its cost of $15.63 million at 1 September 1998. The RAB of $494.2 million at the end of 2002, as indicated in Table 2.4 in section 4.1.7 includes the Murray Valley Pipeline.

Interconnect Assets

As the Commission has previously approved the roll-in of GasNet’s investment in these assets, it will be reflected in the revised capital base as at 31 December 2002.

Other projects

As noted in the Draft Decision, the Commission considered that GasNet’s capital expenditure during 1998-2002 on the following projects satisfied the section 8.16 tests:

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137 From its commencement in 1998 until 2033, being the assumed asset life for the majority of the PTS.

138 For example, it is assumed that tariffs for the remainder of the project’s life will be the same as those proposed for the second access arrangement period and that volumes beyond 2007 are the same as those forecast for 2007.

- automation of the Gooding and Brooklyn compressors ($7 million);
- compressor restaging and cooler upgrade for the Brooklyn compressor ($1.8 million); and
- minor projects, mainly for maintenance purposes ($3 million).

No specific comments were received on these projects from interested parties in response to the Draft Decision. The Commission has decided to confirm the assessment in its Draft Decision that these investments satisfy section 8.16. They will be reflected in the revised capital base as at 31 December 2002.

Pursuant to section 5.7.1 (b) of the GasNet access arrangement, GasNet has advised the Commission that it had commissioned a new extension to the PTS known as the Somerton lateral in December 2001.[139] GasNet advised that the pipeline, which cost $3.4 million, has a diameter of 250 mm, is 3.4 km long and extends in a westerly direction from the Keon Park to Wollert pipeline at O'Hearns Road to supply AGL Power's power station on O'Hearns Road, Somerton. GasNet has not proposed to include any of the capital expenditure in the capital base because of 'the complexities of rolling-in the capital for a small lateral'. GasNet acknowledges that 'the asset is covered, but has no value in the Capital Base'.[140]

4.3 Redundant assets

4.3.1 Code requirements

Section 8.27 of the Code allows a reference tariff policy to include (and the regulator may require that it include) a mechanism that will remove redundant capital from the capital base at the start of a new access arrangement period. The adjustment is to:

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

Before approving a redundant capital policy the regulator must consider the uncertainty the mechanism would cause and the impact this would have on the service provider, users and prospective users.

Section 8.28 of the Code provides that where redundant assets subsequently contribute to the delivery of services the assets may then be treated as new facilities investment and included in the capital base.

While the Code permits a reference tariff policy to include a mechanism to subtract redundant capital from the capital base, it also allows (under section 8.29) for other

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139 GasNet notification to the Commission, 21 October 2002.

140 GasNet response to the Commission, 3 October 2002.

mechanisms that have the same effect on reference tariffs while not reducing the capital base.

4.3.2 Current access arrangement provisions

Clause 5.3.5 of the PTS and the WTS access arrangements allow the Commission to review and, if necessary, adjust the relevant capital base for wholly or partially redundant assets. This is to occur at the start of the subsequent access arrangement period.

4.3.3 GasNet proposal

GasNet has proposed the removal of the cost of the North Paaratte Odorant Station, and certain land and vehicles from its revised capital base on the basis that they are fully redundant.[141]

The North Paaratte Odorant Station ceased operation 2001 and no longer makes any contribution to the pipeline. The written down regulatory value of $0.2 million has been deducted from the capital base.

Since 1998 GasNet has disposed of a number of assets such as land and vehicles. For this reason, a total of $1.8 million should be removed from the capital base.[142]

GasNet has not identified any partially redundant assets.

4.3.4 Submissions to Issues Paper

No submissions have been received concerning assets that may now be fully or partly redundant.

4.3.5 Draft Decision

The Commission assessed the items listed by GasNet as redundant or disposed of. While the Commission raised with GasNet some concerns over the calculation of the values associated with these items, these mainly related to timing and modelling details and did not bring into question the fundamental valuation of these items. These revised figures need to be reduced by the exclusion of two assets listed by GasNet as redundant which are part of the assets GasNet has sought to be included in the revised ICB. As the Commission proposed not to allow these to be included in the ICB, they should also be excluded from the sum of redundant assets. Their value is small and the total of redundant assets (rounded to the nearest tenth of a million dollars) remained the same as proposed by GasNet.

The Commission was unaware of any other assets which should be considered redundant, or which were disposed of during the period.

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[141] GasNet submission, 27 March 2002, p. 19.

[142] ibid., p. 36.

4.3.5 Response to Draft Decision

No submissions were received on this issue in response to the Draft Decision.

4.3.5 Final Decision

As no submissions were received on the Draft Decision and no new issues have come to light, as proposed in the Draft Decision, the Commission accepts the amount nominated by GasNet for redundant assets when modified by the removal of those assets which have not been accepted into the RAB. No amendment to the access arrangement or access arrangement information is required by the Commission because the removal of these assets does not change the figures contained in those documents. However, the Commission expects the models which calculate the proposed tariffs will be appropriately modified. The relevant figures, as amended by GasNet on 19 July 2002, are contained in Table 4.4 in section 4.1.7 above.

5. Rate of return

5.1 Code requirements

When setting revenue benchmarks, sections 8.30 and 8.31 of the Code require the implied rate of return on the regulatory value of the business' assets to be determined according to the following principles:

> The Rate of Return used in determining 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).
>
> By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model. 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 where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

The first provision requires the implied return factored into the assessment of the reference tariffs for a service provider's regulated activities to reflect the opportunity cost of capital associated with those activities. This concept is discussed below.

The second provision provides additional guidance on how to estimate the cost of capital associated with the business' regulated activities. It specifically allows for returns to be determined on the basis of a well-accepted financial model, such as the CAPM.[143] This model is discussed further below. It also encourages the use of benchmarks for such matters as financing arrangements – which is discussed further in section 5.4 below.

Section 8.1 of the Code also provides relevant guidance for determining the rate of return. An important theme of all but one of these objectives is the pursuit of economic efficiency. Two factors necessary for economic efficiency are: for investors to expect to receive a stream of income over the life of an asset that is at least equal to the cost of an asset; and that average prices to customers be as low as possible but sustainable. These factors can be reconciled by setting price controls based upon an unbiased estimate of the efficient cost of providing the service. While this principle applies across all of the assumptions factored into the price controls, it implies that the return should reflect an unbiased estimate of the cost of capital.

In assessing revenue benchmarks the regulator must also take into account the factors described in section 2.24 of the Code and the provisions of the access arrangement (section 2.46). In some cases these considerations are largely consistent with the

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[143] An explanation of the cost of equity capital and the role of the CAPM is outlined in ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002.

section 8.1 objectives. For example, it would be consistent with the legitimate business interests of the service provider and its investment in a covered pipeline for it to receive a stream of income over the life of an asset that is at least equal to the cost of an asset (section 2.24(a)). Also, it would be in the interests of users and prospective users for average prices to customers to be as low as possible but sustainable (section 2.24(f)). However, the regulator must also take into account broader considerations such as the public interest (section 2.24(e)).

5.2 Current access arrangement provisions

In its 1998 Final Decision on the access arrangements for regulation of GasNet's transmission pipelines the Commission approved a WACC calculated from the cost of equity (r_e) and the assessed cost of borrowed funds (r_d):

$$WACC = r_e \times \frac{E}{D+E} + r_d \times \frac{D}{D+E}$$

where E/(D+E) and D/(D+E) are respectively the shares of equity and debt in the financing structure of the asset.

The return on equity (r_e) was calculated using the CAPM. The return on debt (r_d) was calculated as the risk free rate plus a debt margin thought relevant to raising borrowed funds at the time of the decision. It is notable that the return on equity indicated by CAPM is a post-tax rate of return and the WACC formula noted here is sometimes referred to as the 'vanilla' WACC. It is the return the company would require to meet its cost of capital if it was not required to pay company tax. Therefore, an additional element of return is required to cover tax liabilities that the company may face in order to have an expectation of achieving the benchmark return implied by the WACC formula.

In 1998, the additional compensation for tax was provided for by the application of a pre-tax WACC. That is, it was a modified WACC formula which effectively gave a WACC premium (sometimes referred to as the tax wedge) to cover expected tax costs. The important feature of the tax component of revenues is that it was not intended to cover current taxes (which may be very low) but rather to cover tax costs anticipated in a net present value (NPV) sense over the life of the assets.

The applicant at the time proposed a formula for calculating the tax wedge recognising the operation of the tax imputation system in Australia. The formula, developed by Professor Bob Officer related to an annuity and did not capture other features of the tax system in Australia (such as accelerated depreciation) and inflation effects which significantly influence the timing and impact of tax payments on the company and its investors. Hence, the Commission applies a cash flow approach to make a more realistic assessment of tax liabilities for the purpose of determining what value of the pre-tax WACC may be appropriate to establish the return on capital component of the revenue requirement. In the 1998 Final Decision the vanilla WACC was estimated to be 6.94 per cent and the real tax wedge set at 0.81 per cent to give a pre-tax real WACC of 7.75 per cent, which was commensurate with a return on equity of 13.2 per cent.

While the Commission accepted the application of a pre-tax WACC on that occasion, it noted in its decision that the approach was fundamentally flawed. First, it required long term forecasts of Australian tax legislation which are difficult to forecast and may prove to be incorrect. Second, tax liabilities are expected to increase significantly in later years while compensation for tax has been provided substantially in advance. This effect, called the S-bend issue in the earlier decision, was seen as potentially creating a tension between the regulatory framework and the cash flow needs of the company to meet its tax liabilities when they occur.

To overcome these problems the Commission made it clear in the 1998 Final Decision that it intended to assess all future access arrangements on a post-tax basis. That is, there would be no anticipatory compensation for tax but rather tax would be assessed on an 'as you go basis' and the regulatory return would be based on the vanilla WACC. In such a framework the financial circumstances of the company, as reflected in regulatory accounts, would be used to estimate a benchmark tax liability relevant to the regulatory period under consideration. This tax liability estimate would be compensated for as explicit cash flows in the regulatory revenue calculation. The Commission has used this approach in all subsequent regulatory assessments for gas pipelines. Where taxes were thought to create a jump in revenue requirements and hence tariffs, the Commission has proposed modification of the depreciation profile to create a smooth revenue path (known as the 'normalisation' approach'). This results in a revenue path similar to that which would emerge in a pre-tax framework. In this approach, the pre-payments of tax compensation may be interpreted as a return of capital which is reversed when tax becomes payable. Further details of this approach may be found in the Commission's *Post-tax Revenue Model Handbook.*[144]

One factor impacting on an estimate of the tax liability is the provision for accelerated depreciation in the Australian taxation system. This creates a tax benefit, that is, it defers tax liabilities, for many years. The 1998 Final Decision noted that, as a result of this provision, the service provider would be expected to pay little or no tax for the first years of operation.[145]

5.3 GasNet proposal

GasNet has proposed a WACC formulated in exactly the same way as in the first access arrangement period. However, it has proposed updated values for a number of the CAPM and WACC parameters. The Code requires:

> ... a return which is commensurate with the prevailing conditions in the market for funds and the risks involved in delivering the Reference Service[146]

Therefore, updating such parameters is necessary if the cost of capital is to remain appropriate under the financial conditions expected during the forthcoming access arrangement period.

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144 ACCC, *Post tax revenue model handbook*, October 2001.

145 ACCC, 1998 Final Decision, pp. 169-174.

146 Introduction to section 8 of the Code.

In addition to the return on capital embodied in the application of the WACC, GasNet has proposed a number of cash flow adjustments to reflect specific asymmetric risks that are not addressed by the CAPM.

The CAPM and WACC parameter values being proposed by GasNet are detailed in the following sections and compared with the values approved in the 1998 Final Decision. The rationale given by GasNet for its preferred parameter values and the Commission's assessment of risk claims are also discussed.

Notably, GasNet has proposed to continue with a pre-tax approach despite comments in the 1998 Final Decision drawing attention to the fundamental difficulties of that framework. To convert the vanilla WACC into pre-tax form, GasNet has estimated a value for the tax wedge by applying a simplified financial model of the company's cash flows rather than relying on the more detailed model used to establish actual reference tariffs. The simplified model used is one of the Commission's own illustrative models published in conjunction with the *Post-tax Revenue Model Handbook.* The model in question uses a normalisation procedure (adjusting the depreciation profile) to generate revenues in a post-tax framework which are smooth and unaffected by tax payments when they become due. The 'tax wedge' is deduced by noting the increment of revenues above what they would have been if no company tax was imposed over the life of the business. In making the calculations GasNet made two key explicit assumptions:

- the value of the regulatory assets was written down for tax purposes relative to their regulatory value; and
- tax depreciation on the written down value was straight line over the remaining economic life of the assets (that is available tax concessions were assumed not to apply).

GasNet established the pre-tax WACC using this approach. It then utilised the figure in its detailed asset and cost allocation model to derive reference tariffs and forecast revenue requirements.

As noted above, the use of a pre-tax WACC in the first period means that the approved tariffs contained an allowance for tax liabilities which GasNet is yet to incur. Consistent with the Commission's current post tax approach, it could be argued that this prepayment of tax should be recognised (in the switching to a post-tax framework) as extra depreciation, which would lower the capital base for the next access arrangement period. GasNet submitted that the Commission should not revisit its approval of the current tariffs and adjust the capital base for amounts related to the pre-payment of taxation liabilities. It also considers that the benefits of accelerated depreciation for tax purposes should be retained by GasNet because it would:

- be consistent with the government policy objectives;
- reflect the behaviour of a competitive market; and
- be consistent with the Commission's 1998 Victorian decision.[147]

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[147] GasNet submission, 27 March 2002, p. 60.

GasNet included a report it commissioned by Network Economics Consulting Group (NECG) in support of this position.[148] NECG provided 'selected quotes' relating to the policy objective of accelerated depreciation to provide an incentive to investment in certain assets.[149] NECG noted that as a consequence of the Government's decision to implement aspects of the Ralph Committee recommendations, the provision for accelerated depreciation has been removed for assets acquired or commenced to be constructed from 21 September 1999. NECG considered that the 'grand fathering' of accelerated depreciation provisions for assets constructed or acquired before that date demonstrates a recognition by the Commonwealth Government that accelerated depreciation benefits represents a property right that is vested in infrastructure owners.[150]

NECG considered that the Commission's suggested approach of adjusting the capital base for the value of accumulated deferred company tax liabilities would transfer 'the financial benefit of accelerated depreciation from the investor to its customers'.[151]

NECG concluded:

> If the ACCC persists with this initiative, so far not applied to GPU GasNet's Principal Transmission System, but advocated in the context of the Draft Decision on the MSP Access Arrangements, the investment incentives intended through accelerated depreciation will be entirely negated retrospectively.
>
> The provision of the subsidy occurred in an environment where pipelines were in a position to extract virtually all of the benefit of the subsidy. It is these benefits that encouraged the investment in the pipeline in the first place. The approach proposed by the ACCC will offset the incentives that accelerated depreciation was intended to impart. The result is even inconsistent with the outcomes one would expect from a competitive or contestable market.[152]

5.4 Commission methodology and approach

Pre-tax and post-tax

As noted earlier, the Commission has strongly signalled its preference for a post-tax approach in calculating the cost of capital or WACC. Within this framework return on capital invested is covered by applying the vanilla WACC, which would be the rate of return on assets required if no company tax was payable. There is no requirement to calculate a tax wedge. Instead, tax liabilities are compensated for explicitly by an allowance in cash flows to cover anticipated taxes when they are due.

The alternative approach of applying a simple transformation formula to derive a long term estimate of likely tax liabilities is dubious. First, the assumptions regarding the tax system in the use of the transformation approach are far from obvious, are certainly not transparent and do not promote an informed debate. Different regulators have

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148 NECG, *Asset, equity and debt beta*, 4 January 2002 (GasNet submission, 27 March 2002 annexure 5).

149 ibid., pp. 6-9.

150 ibid., p. 9.

151 ibid., p. 10.

152 ibid., p. 17.

applied several incompatible variations of the transformation approach but none give outcomes consistent with what might be viewed as reasonable cash-flow simulation of tax liabilities. For these reasons the Commission has avoided any of the transformation approaches as a basis for assessing the amount of compensation for tax to be added to post-tax revenue estimates in order to give a reasonable expectation of the CAPM based benchmark return being achieved.

The GasNet proposal is a pre-tax framework and retains all the problems of that approach. Its partial use of a post-tax revenue model developed by the Commission does not alter this fact. Indeed, the assumptions adopted by GasNet in using the model serve to illustrate some of the problems of the pre-tax approach:

- a realistic assessment of tax is prevented by assuming a value of zero for tax concessions, which in reality are clearly available to the firm; and
- there is a need to make long term forecasts of future tax legislation, which increases uncertainty for the firm in how it will meet its future tax liabilities while retaining the desired post-tax return.

Perhaps the issue of greatest concern with the GasNet proposal is that, in determining the tax wedge designed to cover future tax liabilities, it explicitly requested that payments already received, which were designed to compensate for future taxes should be ignored. This is directly related to the S-bend issue noted in the 1998 Final Decision. This means that while approximately $16 million for future tax liabilities was included in the benchmark revenue in the first access arrangement period, GasNet is asking that the benchmark revenues from 2003 onwards reflect compensation for the full amount that GasNet needs to pay its tax liabilities. This is a violation of the regulatory compact that requires that the company not seek to be compensated for expected tax liabilities more than once.

GasNet in its modelling does not provide an accurate representation of its tax position for the purpose of establishing reasonable estimates of benchmark tax liabilities. Specifically, the proposal ignores:

- accelerated depreciation tax concessions available on its existing regulated assets; and
- its initial tax position at the start of the new regulatory period. The tax position, including any carried forward tax loss is important in making a realistic assessment of future tax liabilities for which compensation is required.

GasNet had misinterpreted the way the ‘normalisation’ procedure would work in the Commission’s post-tax regulatory framework. In particular, there appeared to be a perception that the procedure would alter the WACC (pre-tax or otherwise) that is to be applied in the framework. This is not the case. The normalisation procedure is purely a contouring of the regulatory depreciation profile in a way which is designed to avoid a jump in regulatory revenues and tariffs when taxes become payable and are added to the target revenue stream.

To overcome the problems with the pre-tax approach and to promote transparency, and consistency, the Commission requires a move to a post-tax approach. In this approach the vanilla WACC provides an appropriate guide for the return required on assets provided there is an explicit compensation for tax in cash flows.

The Commission understands that the GasNet model provided with its access arrangement revisions was intended to incorporate normalisation. However, the model maintained straight-line depreciation throughout and did nothing to create a contouring of depreciation to accommodate tax related cash flows. Consistent with this approach, the Commission did not incorporate normalisation as part of its revenue assessment for the Draft Decision. This was not a rejection of normalisation principles but merely a measure to maintain consistency with the model provided by GasNet. GasNet considered that normalisation could be achieved by adjusting the tax payments. However, the Commission noted this was not appropriate as it would introduce the same problems that are associated with the pre-tax approach (which were discussed in the 1998 Final Decision).

The Commission noted that the PTRM (published with the *Post-tax Revenue Model Handbook)* could be used in conjunction with GasNet's Asset/Revenue/Tariff model provided the aggregate depreciation recorded in the GasNet model could be made to correspond precisely with the normalised depreciation schedule indicated by the PTRM. GasNet agreed to modify its model in this way with the relevant WACC being the vanilla WACC as indicated in the Draft Decision.

Normalisation results in slightly higher revenues being projected in the 2003-2008 regulatory period than without normalisation. However, it must be appreciated that this arises because of additional depreciation being included in revenues to effect the normalisation. The higher revenues do not reflect a change to the WACC. A consequence of the higher depreciation, prior to benchmark estimates of taxes being payable, is that depreciation in later years is reduced. Hence, the future revenues which include compensation for benchmark tax liabilities are lower than they would be in the absence of normalisation. That of course is the purpose of normalisation.

The Commission shares the view of GasNet that the CAPM and WACC parameters needed to estimate the (vanilla) WACC will require updating to reflect current financial conditions as required by the Code. However, many of the changes proposed by GasNet reflect a changed perception of risks faced by the service provider. The Commission does not agree with many of these changes. Individual parameters are discussed in detail in the following sections along with the Commission's response to the proposals.

Establishing benchmark tax liabilities

A key objective in determining the allowance for taxation is that it reflects an unbiased estimate of tax liabilities for an efficient company. Most 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 revenue benchmark;
- operating expenditure – assumed to be the operating expenditure benchmark;
- capital expenditure – taken to be historical and forecast capital expenditure; and

- interest expenses – taken as the nominal interest payments implied by the benchmark financing arrangements (gearing, in particular).

The remaining information required relates to the tax position of the regulated business at the start of the next access arrangement period and information to determine depreciation allowances for taxation purposes. These are the two items noted above that GasNet did not supply with its model.

The tax position is essentially defined by the carried forward tax loss which can be offset against future income to diminish future tax liabilities. Tax depreciation, which is a recognised cost by the Australian Taxation Office and is available to reduce assessable income, depends on:

- the opening value of the assets for tax purposes;
- the depreciation rates and method (straight line or diminishing value) assumed for each asset class; and
- the proportion of capital expenditures that fall into each class.

Opening tax value of assets and carried forward tax loss

To establish the firm's current tax position, knowledge of the provisions available to reduce (or defer) tax liabilities is required. An important element of this is the written down value of the assets at the start of the access arrangement period for tax depreciation as this determines the amount of remaining tax depreciation that can be assigned to reduce assessed income and hence the associated tax liability. When the tax depreciation results in assessable income being negative so that no tax is payable, the excess usage of depreciation applied is not lost but is carried forward as a tax loss which may be assigned to reduce positive income and tax liabilities in future periods. Therefore, the remaining available value of assets for tax depreciation and the carried forward tax loss together define the starting tax position of the firm in any period and have a significant bearing on tax payments that will be due in the period.

In order to establish GasNet's tax position going into the new access arrangement period the Commission has re-modelled the regulated cash flows over the initial access arrangement period on the assumption that no pre-tax compensation was received. Since that period represented the commencement of regulated operations it was assumed that there was no prior accumulated tax loss (or profit) and the initial value of the assets for tax purposes was equal to the ICB established in 1998 at the commencement of the first access arrangement period. While this assumption represents a windfall gain to GasNet, the Commission is inclined to over look this pre payment of tax to facilitate the move to the post tax approach. Revenue requirements for the second access arrangement period were calculated applying the standard post-tax framework. The recalculation of revenues for the previous period was necessary to capture the impact of significant enhancements of the access arrangements during the period (for example, the inclusion of the Interconnect Assets) and to establish the benchmark tax position at the commencement of the next regulatory period. The result obtained was that the benchmark company accumulated a forecast carried forward tax loss of $175.4 million and a forecast written down value of the assets for tax purposes of $195.3 million at the end of 2002. These forecasts have a significant bearing on how far into the future taxes will actually become payable.

Depreciation rates

GasNet has proposed that the tax assessment ignore the availability of accelerated depreciation but not the imputation system, arguing that the regulatory framework should not remove an industry benefit intended by the government. This view fails to appreciate that the regulatory framework provides a benchmark return required by investors and investors benefit from accelerated depreciation in exactly the same way as they would if the company was not regulated. For an expansion on this point see Figure 5.1 below.

Figure 5.1: The impact of accelerated depreciation in the presence of tax imputation

The benefits of accelerated depreciation to an Australian investor are the same whether or not the firm is regulated. This is easily seen by noting what happens to investor post-tax returns in a non-regulated firm. Suppose 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, tax imputation provides the Australian investor with a credit or rebate restoring his effective gross return (after company tax but before personal tax) 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. So the investor receives no direct benefit from the accelerated depreciation. The regulatory assessment of tax recognises both imputation and accelerated depreciation and therefore has a similar impact as for an unregulated firm.

This does not mean that the industry does not benefit from the tax concessions discussed. The availability of imputation significantly improves returns to investors and enables prices to be reduced allowing both users and investors to be better off. Some classes of investors benefit more than others. For example, foreign investors who receive minimal benefit from imputation credits benefit from accelerated depreciation where as Australian investors who receive the value of imputation credits, as noted above, receive no additional return from deferral of tax from accelerated depreciation.

The addition of accelerated depreciation improves cash flows in the short term and allows the company to remain sustainable with lower revenues while its customer base is being established. There are additional benefits available to conglomerate firms as well, which are beyond the scope of the present discussion.

Within the regulatory framework the Commission, to date, assumes that investors, on average, are unable to fully utilise the available imputation tax credits. This has the effect of sharing the benefits of accelerated depreciation and imputation between users and investors. This is consistent with the Code which suggests tariffs should be set to mimic the behaviour of a competitive market.

As noted above, GasNet proposed that the benefits of accelerated depreciation should be retained by GasNet because it considered this would be consistent with government policy to stimulate investment in the gas sector, reflect the behaviour of a competitive market and be consistent with the Commission's 1998 Victorian decision. GasNet believes this would be achieved by calculating regulatory revenue requirements as if accelerated depreciation was not available on GasNet's infrastructure assets. This would have the effect of raising regulatory revenues and raise expected returns well above those indicated by CAPM as being an appropriate commercial return.

This would be a somewhat perverse approach since it would require the regulator to ignore the existence of some aspects of tax legislation and not others. It would actually be contrary to GasNet's other stated objective 'to reflect the behaviour of a competitive market'[153] where competitive processes would tend to restore returns to benchmark levels resulting in benefits being passed onto customers in lower prices – not higher prices.

The approach is not comparable with the 1998 decision since, at that time, the assets were not in private ownership and were therefore subject to a different taxation treatment.

If accelerated depreciation is intended by the government as an instrument to stimulate gas sector investment, the regulatory framework achieves this in two ways. First regulatory revenues are reduced while allowing investors to maintain market commensurate returns so that users benefit from lower prices and service providers from higher demand. This occurs because the regulatory framework assumes that investors receive imputation benefits from taxes paid by the firm. Second, the different classes of investors benefit in exactly the same way as they would if the assets were not regulated. This is also a result of dividend imputation (see Figure 5.1 above for a brief explanation).

These points serve to undermine GasNet's assertions that the regulatory framework should ignore the existence of accelerated depreciation. The regulatory framework not only gives an outcome reflective of a competitive market but returns to different classes of investors are affected in the same was as they would be if the assets were not regulated. In this way, the Commission considers that the framework meets both the objectives of government industry policy and the objectives of regulation.

Therefore, the Commission believes its approach to assessing benchmark tax liabilities is appropriate and does not distort any industry benefits intended from concessions available under current Government tax policy. Moreover, it is the approach which best meets the guidance of the Code which suggests that tariffs should be set to reflect the tariffs that are likely to emerge in a competitive market. Under competition any tax concessions of this nature would normally be reflected in lower prices to customers and provide a stimulus to industry development from increased demand.

NECG, on behalf of GasNet, argues that adjusting the rolled forward value of the capital base to reflect the rundown of tax depreciation benefits (referred to as the accumulated deferred tax liability) was not appropriate. Nevertheless, the tax value of assets does have economic value and the utilisation of available accelerated depreciation does represent a financial benefit to the firm linked to assets. However, the Commission does not seek to reflect the historic consumption of this aspect of asset value by a reduction in the carried forward value of the asset base. Therefore these arguments made by GasNet and NECG are irrelevant.

In terms of asset classes and depreciation rates applicable to each, a detailed assessment was not made in the Draft Decision. However, GasNet has chosen to link tax depreciation to specific assets. To achieve this it has included in its regulatory asset base model calculations pertaining to the roll forward of asset values for tax purposes in a similar way to regulatory asset values. To maintain consistency the aggregate tax

[153] GasNet submission, 27 March 2002, p. 60.

asset depreciation is subsequently linked to the modified PTRM model used to facilitate the normalisation procedure.

The Commission's modelling in the Draft Decision took into account that the opening asset values of assets in the ICB plus additions to the asset base until 20 September 1999 (prior to business tax reform) are subject to straight line tax depreciation at the rate of 13 per cent per annum whereas from 21 September 1999 straight line depreciation at the rate of 5 per cent per annum is applicable on new capital expenditures.

The taxpayer may also choose to apply diminishing value tax depreciation at a rate 50 per cent higher than the straight line rate. For a stand-alone corporate operation this seems to provide little additional deferment of tax payments. For simplicity, the Commission in the Draft Decision assumed straight line depreciation to estimate the tax liability benchmark. However, GasNet in its modelling has chosen to apply diminishing value tax depreciation consistent with the approach it uses in its statutory accounts. As noted this makes little difference to the tax implications and the Commission is comfortable with this approach.

5.5 Determination of the return on equity

5.5.1 Interest rates and inflation

Interest rates

Current access arrangement provisions

The risk-free rate (r_f) is an important parameter which is used to determine both the cost of debt and the cost of equity. The risk-free rate measures the return an investor would derive from an asset with certainty of return being achieved. Most regulators, including the Commission, have approximated the risk free rate by the yield to maturity on government bonds, as the government is in a position to honour all interest and debt commitments.

The Commission adopted a five year term when estimating the risk-free rate at the start of the first access arrangement period for the GasNet access arrangements. A 40 day moving average of this five year rate was taken to minimise the impact of short term spurious movements in relevant interest rates.

GasNet proposal

GasNet proposed maintaining the approach of equating the risk-free rate with the return on Commonwealth Government Bonds. GasNet submitted that 10 year bond rates should be used as the basis of the risk-free rate. It argued that 10 year real rates are preferable to five year rates (which equate with the length of the access arrangement period) as 10 year rates match the long-term nature of the investment and are less volatile than five year rates.

In relation to the measurement of the risk-free rate, GasNet proposed that a 40 day averaging period should be maintained, and that the appropriate averaging period and dates to be used should be agreed in advance of the Final Decision. GasNet requested that this period be determined on a confidential basis between GasNet and the Commission, and only be disclosed to the market after the event so as to prevent any arbitrage opportunities arising.

Submissions to Issues Paper

In its submission to the issues paper, BHP Billiton stated that the Commission should apply the five year bond rate instead of the 10 year bond rate. It argued that this is because the five year bond rate has more justification than using the 10 year bond rate, as it matches the regulatory period. BHP Billiton added that GasNet prefers the longer term rate as it leads to a higher WACC.[154] Amcor and PaperlinX concurred on the appropriate maturity period, stating that:

> The ACCC approach to the risk free rate (5 year bonds) is correct as it matches the forward looking period of the access arrangement and reflects the expected risk profile of the period under review.[155]

The Commission sought advice from Dr Martin Lally on several risk free rate related issues.[156] Lally assessed the arguments proposed for not using the five year bond rate and determined that these arguments are largely unfounded. He concluded that the five year bond rate is the appropriate bond term to consider when the regulatory period is five years.

Draft Decision

Under section 8.30 of the Code, the Commission is required to set a rate of return 'commensurate with prevailing conditions in the market for funds'. This implies that information used in deriving the rate of return should be as up to date as possible and reflect the circumstances (economic conditions) of the regulatory framework.

In accordance with these requirements, the Commission considered that it is appropriate to maintain the use of interest rates that correspond with the length of the access arrangement period. Thus, for GasNet, which is seeking a five year access arrangement period, the yield on bonds with a term to maturity of five years should be used. It was argued that the adoption of this methodology should ensure that the expected regulatory return over the sequence of reviews will match the initial risk-free rate expected by the market over the life of the asset. This approach should provide GasNet with the right signals for investment at all times. Further, the Commission maintained the use of a 40 day moving average of rates to smooth out any short-term volatility that may occur in bond markets.[157]

As noted above, GasNet proposed that the Commission inform it of the averaging period to be used to measure the risk-free rate in advance of the Final Decision. GasNet requested this information so that it could organise its market hedging activities. The Commission was aware of no reason why it should not provide the

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154 BHP Billiton submission, 21 June 2002 pp. 33-34.

155 Amcor and PaperlinX submission 24 June 2002, p. 23.

156 M Lally, *Determining the risk free rate for regulated companies*, a paper for the ACCC, July 2002.

157 The Commission is currently in the process of reviewing its methodology for determining the risk-free rate.

information as requested. The Commission proposed to advise GasNet of the relevant period no later than four weeks before the expected release of its Final Decision.

In accordance with the above approach, for the Draft Decision a nominal risk-free rate of 5.72 per cent and an interpolated real risk-free rate of 3.14 per cent were used.[158] It was noted that these rates were only indicative as they would be recalculated prior to the Final Decision.

Response to Draft Decision

The EUCV, in its response to the Draft Decision, agreed with the Commission that 'using the five year bond rate appropriately reflects the risk free interest rate and inflation risk profile expected over the access arrangement period'.[159]

GasNet stated that the Commission is alone in using the 5 year rather than the 10 year rate. GasNet argued that the decision to use 5 year rates stands in contrast to the recent ESC draft decision for the three Victorian gas distributors. GasNet stated that regulators have an obligation to ensure that they are consistent on technical issues.

GasNet stated that in conjunction with SPI PowerNet and ElectraNet it held a seminar on the risk-free rate and other WACC issues on 24 June 2002. GasNet noted that both Professor Officer and Mr Ergas agreed that the appropriate value for the risk-free rate was the 10 year rate. Furthermore, GasNet commissioned David Robinson of Ernst & Young to review the paper by Dr Martin Lally on the risk-free rate. GasNet asserted that this paper found that arguments supporting a five year rate are not persuasive and that the risk-free rate should reflect the long-term nature of the investment. The main arguments put forward in this paper include:

- investors assess both risks and returns when making investment decisions, and evaluate the present value of the expected cash flow stream from assets to make a suitable comparison. When making this comparison, it is imperative that the maturity of the discount rate be matched directly to the timing of expected cash flows or else the analysis will under or over value the present value of expected cash flows. Ernst & Young asserted that the review period is not relevant to the assessment of expected return achieved from holding an asset over its life, but that the rate applied for discounting purposes must reflect the long-term nature of the asset;
- Ernst & Young argued that its assessment is supported by a number of leading academics. For example Damodoran argues that 'using a long term government rate (even on a coupon bond) as the risk free rate on all of the cash flows in a long term analysis will yield a close approximation of the true value. For short-term analysis, it is entirely appropriate to use a short term government security rate as the risk free rate';[160]

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[158] Calculated 30 July 2002.

[159] EUCV submission, 13 September 2002, p. 6.

[160] Ernst & Young, *Review of issues in the estimation of the risk free rate for regulatory purposes,* report prepared for GasNet Australia, September 2002, pp. 6-7 (GasNet submission, 20 September 2002, Appendix A).

- the risk free rate should reflect the rate of return that allows investors to preserve the initial capital expended in their investment. Ernst & Young argued that for this to occur it must reflect the economic life of the asset and that the argument for using a regulatory period linked rate would only be true if it could be sure that it would be compensated if the asset was stranded at the end of the regulatory period;[161] and
- the setting of the market risk premium should reflect the maturity of the long-lived economic life of assets. Ernst & Young asserted that Lally argues that the risk-free rate must correspond to the investor horizon otherwise biases will occur in the estimation of the market risk premium.[162]

Ernst & Young also commented on the paper by Lally in relation to the risk free rate. With regard to the arguments put forward for the use of rates linked to the regulatory period, some observations include:

- the mathematical analysis presented by Lally is correct within the bounds of the assumptions made and reported. However, Lally's analysis refers to the rate of return whereas the paper only discusses the nominal risk free rate which constitutes just one aspect of the rate of return analysis;[163]
- the approach adopted by Lally directly links the prevailing interest rate for the current regulatory period to the long term investment horizon, which distorts benchmarks and suggests that the cost of debt facing a firm can be reset to current market levels at the beginning of each regulatory period;[164]
- the approach put forward by Lally assumes that the life of the asset can be neatly packaged into five year intervals;[165]
- the regulated entity is assumed to face zero volume risk which is consistent with a revenue cap rather than a price cap; and[166]
- a material change in market risk premium estimates may occur should the risk free rate used for this calculation be reduced to five years.[167]

On the issue of forecast inflation, it was noted that most Australian regulators now adopt the implied inflation method, and that Lally noted a number of concerns with this methodology. Ernst & Young added that regulated firms are exposed to the risk that expected inflation will differ from actual inflation during the life of the asset given that firms typically borrow in nominal terms. Ernst & Young stated that the process of linking the risk free rate to the regulatory period will not eliminate this risk.[168]

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161 ibid., pp. 6-7.

162 ibid., p. 8.

163 ibid., p. 10.

164 ibid., p. 10.

165 ibid., pp. 11.

166 ibid.

167 ibid.

168 ibid., p. 12.

The issue of the averaging methodology was also discussed. Ernst & Young commented that:

> There is no theoretical rationale available that suggests an optimal structure for smoothing. Therefore, the choice of any approach to smoothing applied should not disadvantage the firm or investors relative to current market yields.[169]

Ernst & Young also commented on the issue of forward rates and suggested that the use of such rates is not endorsed as it would require continual yield curve monitoring. The authors, however, endorsed the approach of advising regulated entities of the averaging period and the determination date in advance.[170]

Bond rates used for domestic and regulatory decisions were also summarised by the consultants. Ernst & Young noted that most of the Commission's decisions have used five year rates, in contrast with all state based regulators and a number of UK regulators who use 10 or 20 year rates.[171]

GasNet addressed the issue of the averaging period in its response to the Draft Decision. GasNet noted the Commissions adoption of a 40 day average, but suggested that it should also be able to agree on the duration of the averaging period as well as the end date of that period.[172]

Final Decision

The aim of the Commission when establishing the risk free rate is to find the best estimate of its true value given the circumstances of the particular application. As noted in the Draft Decision, the Commission considers that the value must be determined so that it is consistent with the regulatory period, bearing in mind that the regulatory framework involves a sequence of regulatory reviews extending over the service life of the regulated assets.

In themselves, arguments such as those put forward by GasNet, that the Commission should adopt the 10 year bond rate as the benchmark to be consistent with other regulatory authorities, carry little weight. The Commission is of the view that the interests of no party to the access arrangement can claim to be compromised unreasonably if the best estimate of the risk free rate for the circumstances is applied. This is why the Commission sought expert advice from Lally to confirm that the normal approach adopted by the Commission in establishing the risk free rate was indeed theoretically correct and appropriate in practice given the nature of the financial framework being used. Lally's analysis was comprehensive and confirmed that the risk free rate is best determined from yields to maturity on Government bonds with a term equal to the term of the regulatory period (which is usually five years but may be for a different period).

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169 ibid., p. 13.

170 ibid.

171 ibid., pp. 14-15.

172 GasNet submission, 20 September 2002, p. 13.

It is notable that GasNet's own consultant Ernst & Young attested to the correctness of Lally's mathematical analysis.[173] While conceding this fact, Ernst & Young proceeded to mention issues associated with non-risk free investments which essentially cloud the issue and concluded that Lally's result may not be robust. On this basis GasNet, in its submission, asserted that Ernst & Young did not find Lally's analysis persuasive.[174]

Lally's paper is available on the Commission's website for academic scrutiny and stands on the basis of its own logical integrity. While the Commission has taken into consideration the arguments provided by GasNet and its consultant, it does not consider it appropriate or necessary to provide a line by line commentary to demonstrate that they do not undermine the basic conclusion of the Lally report. The Commission instead focuses below on the points reiterated in GasNet's submission.

GasNet stated that the Commission is alone among economic regulators in using a risk free rate from a bond term the same as the period of the access arrangement under consideration. The Commission is not in a position to comment on why other regulators have chosen to persist with the 10 year bond as the benchmark. The Commission's reason for selecting the interest rate associated with bonds with a term corresponding to the length of the access arrangement period as the best estimate for the relevant risk free rate was outlined in the Draft Decision. The finding of Lally's analysis does not require a change from the position the Commission has always adopted. Perhaps, rather than rejecting the Lally result, other regulators have simply chosen to maintain consistency with their own prior decisions. One thing is clear, and that is that the use of a bond term or the risk free rate equal to the regulatory period subject to review is a clearly established benchmark used by the Commission and should not be an unexpected aspect of this decision.

GasNet also noted that speakers (Ergas and Officer) at a conference held by GasNet, SPI PowerNet and ElectraNet concurred that 'the appropriate value for the risk free rate for regulated companies was the 10-year rate'. There is an indication of Professor Officer's thinking in a submission from him in which he commented on the Lally paper on behalf of SPI PowerNet (following the Commission's draft decision on ElectraNet SA Revenue Cap). In this he noted a number of points:

- the ten year bond term better matches the investments duration. Lally's paper deals with this conclusively noting that it does not apply where there are regular tariff reviews as there are under the framework applicable to GasNet;
- Officer favoured the 10 year rate because it maintained consistency with the basis of most studies estimating the MRP also used in the CAPM along with the risk free rate. But he also agreed with Lally that, in principle, the MRP could have been estimated by comparing market and bond returns over periods other than 10 years and therefore does not indicate a 10 year risk free rate needs to be used for consistency. However, Officer does not acknowledge the point being made by Lally that whatever term is used for the MRP estimate the result will be much the same, and, if there are differences, they are likely to be small relative to the inherent uncertainty in the MRP estimation itself. Therefore it matters little if the MRP

173 ibid., p. 10.

174 ibid., pp. 12-13.

determined using 10 year bonds is used in the CAPM alongside 5 year bond yields for the risk free rate; and

- a final comment in Officer's paper seems to support the averaging over a period such as the forty days as used by the Commission to determine the 5 (or 10) year rate that will be used as the benchmark.

The main point picked up by GasNet from the Ernst & Young review is similar to that of Officer. GasNet argued that the bond term needs to relate to the long-term nature of the investment, and stated that 'this is generally taken to be the 10-year government bond rate. The argument that the appropriate maturity period is the term of the regulatory period cannot be supported'.[175] In support of this, GasNet quoted the following from Ernst & Young:

> The argument for using a regulatory period linked rate of return would only be true if the owner of the asset could be sure that they would be fully compensated if the asset was stranded *or abandoned at the end of the regulatory period*.[176]

These comments illustrate part of the flaw in Ernst & Young's and GasNet's thinking. First, the Ernst & Young quote relates to Lally's analysis on the choice of the risk free rate term. Of course, in the context of the risk free rate, the requirement that the owner of the bond will receive back the full value of his investment is assured by the definition given to the risk free rate. The Ernst & Young critique confuses much of the uncertainty associated with actual investments. It notes that the risk free rate models being analysed by Lally do not include the imperfections found in regulated asset investments and therefore cannot be used with confidence. Of course, this fails to appreciate that the whole object of the exercise is to determine the risk free rate pertinent to the access arrangement period, not some other rate. This risk free rate is only subsequently applied in the CAPM/WACC formulation which is used in conjunction with a range of other factors and parameters to derive a market based rate of return. If there is an issue of asset stranding or abandonment, this is normally identified by the applicant and dealt with separately within the access arrangement (for example, through more rapid return of capital).

The other flaw is that in order to derive an appropriate return for a long term asset, it is necessary to apply a long term risk free rate. The only situation where this would be true is where the regulated return and tariff path were to be determined at the start and not changed over the whole life of the asset (possibly 80 years). In this case, the appropriate bond term would not be 10 years either, but rather a bond of 80 year duration (this is conceptual since no such bonds exist) matching the economic life of the asset.

The situation is significantly different when tariffs and returns are reviewed periodically. Such reviews remove much of the uncertainty over future financial markets and this would normally be reflected in the periodically determined returns being smaller relative to the once-off approach. This is not inconsistent with the view of Damodoran and other leading academics referred to by Ernst & Young that the long

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175 ibid., p. 12.

176 Ernst & Young, *Review of issues in the estimation of the risk free rate for regulatory purposes*, report prepared for GasNet Australia, September 2002, p. 7.

bond term bonds should be used to determine the risk free rate for long term analysis, with short term securities being appropriate for short term analysis.

This is neatly demonstrated by an investor seeking a risk free return over 10 years. If he invests in 10 year bonds he receives the risk free rate at the start of the period on the amount invested and his money back at the end of ten years. If instead he is subject to a reset after five years the risk free strategy must be different. Instead, he must invest in five year bonds getting the five year rate at the beginning of the period and after five years he has received this rate of interest and receives his money back as well. He then re-invests all his cash again for five years at the then prevailing interest rate and at the end of year 10 receives both his interest and the total of funds re-invested – no risk.

Suppose instead the investor was subject to five year resets and he invested at the outset in 10 year bonds. He will collect the 10 year rate of interest periodically, but after five years he would be forced to re-sell the bonds on the market. If interest rates have changed he may get back more or less than his capital amount for reinvestment along with the interest he has earned. If he again invests in 10 year bonds at the end of 10 years (halfway through the term of the second set of bonds) he faces additional uncertainty over the capital amount he will receive at the end of 10 years. He may end up with a greater return using this strategy but it could also be less – whatever the outcome - it is not risk free.

In this example the risk free strategy is simple and clear. The investor must invest in risk free bonds with a term equal to the review period. While the above is a simple illustration, it nevertheless shows the appropriateness of using bond rates with a term equal to the regulatory (review) period for the purpose of establishing the risk free rate.

It should also be noted that the regulatory framework is based on an expectation of a real return because tariffs (and asset values) are adjusted annually in line with CPI. This removes inflation risk that might otherwise face the service provider. Ernst & Young claimed that firms are likely to lock in nominal interest rates and this means they are subject to inflation risk. This is partly true but it is a choice that regulated firms need not make. For example, floating rates are more likely to move in line with inflation, and therefore be compensated for, by the inflation adjustment. Alternatively, the firm could seek part of its debt funding based on indexed bonds.

In short, the Commission considers that the arguments presented on the risk free rate in response to the Draft Decision are insufficient to warrant a change in its calculation of the risk free rate. That is, the risk-free rate will be based on the 40 day average of five year Commonwealth government bonds. While GasNet suggested in its submission to the Draft Decision that it should be able to negotiate the duration of the averaging period used, it did not pursue this matter. The Commission confidentially advised GasNet of the 40-business day averaging period used to measure the risk free rate several weeks prior to the release of the Final Decision. The averaging period advised ended on 11 October. In accordance with this methodology, the nominal risk-free rate for the Final Decision is 5.31 per cent and the real risk-free rate is 3.08 per cent.

As noted here, the use of bonds with maturity matching the regulatory period should generate competitive market outcomes and thus provide incentives for efficient investment in the future. Accordingly, the Commission considers that the above approach outlined above promotes the service providers legitimate business interests and investment (section 2.24(a) of the Code), the economically efficient operation of the covered pipeline (section 2.24(d)) and the public interest, including the public interest in having competitive markets (section 2.24(e)). Through encouraging efficient pricing of investment, this approach may also serve the long-term interests of users and prospective users (section 2.24(f)). Compliance of this decision with tariff principles is outlined in section 8.3 of this Final Decision.

Inflation

GasNet noted that regulators have been determining the rate of inflation with reference to bonds that are used to calculate the risk free interest rate. With a view to adopting the same approach, GasNet proposed to use 10 year bonds to determine the expected rate of inflation. However, for the purposes of the proposed revised access arrangement GasNet has used an inflation rate of 2.5 per cent.[177]

The Commission's Draft Decision noted that its approach to determining inflation for regulatory purposes is to use bond rates with a term equivalent to the regulatory period. As a result, the expected inflation rate applicable for the Draft Decision was calculated to be 2.51 per cent. The Draft Decision indicated that the value would be recalculated for this Final Decision.

GasNet agreed that the appropriate method to calculate expected inflation is to use the Fisher equation from nominal and real bond rates. However, it regards the 10 year bond rates as the appropriate rates to use rather than the five year bond rates considered by the Commission to be appropriate.[178]

The issue of the appropriate bond rates to use in calculating the risk free rate for regulatory purposes has been discussed above.

On the basis of the nominal and real risk free rates specified above as relevant for this Final Decision, the expected inflation rate is 2.16 per cent. This value has been incorporated into this Final Decision as required and is to be adopted by GasNet.

Amendment 12

GasNet must adopt a value of 2.16 per cent for expected inflation for the period 2003 to 2007 in its revised access arrangement.

5.5.2 Debt margin and the cost of debt

Current access arrangement provisions

A debt margin of 120 basis points was adopted by the Commission in its 1998 Final Decision.[179] The 120 point margin was added to the yield on a five year nominal risk free rate of 6.0 per cent to obtain a nominal cost of debt figure of 7.2 per cent for use in the WACC estimation.

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177 GasNet submission, 27 March 2002, p. 54.

178 GasNet submission, 20 September 2002, p. 13.

179 The current access arrangement provisions implicitly assume the inclusion of bank costs in the debt margin for the purposes of the calculation of the debt beta.

GasNet proposal

In its proposed access arrangement revisions, GasNet suggests that 120 basis points represents an appropriate debt margin for a company with GasNet's characteristics, and that the cost of debt should be determined on the basis of this margin.

Draft Decision

In the Draft Decision, the Commission reiterated its position that the regulatory debt margin should be determined through reference to a benchmark margin consistent with other benchmarks adopted, as the actual cost of debt may not reflect efficient finance sourcing. It was noted that the calculation of the benchmark debt margin is essentially an empirical matter which can be divided into two empirical questions: the appropriate benchmark credit rating of the service provider; and the market observed debt margin associated with that benchmark rating.

With regard to the credit rating of a service provider, it was proposed that Australian gas transmission and distribution companies should be used as the basis of a benchmark and that for matters of consistency the companies should be stand-alone entities and void of government ownership. Further, it was considered important that the gearing ratio of the entities used to calculate the debt margin should not be significantly different from the gearing assumptions used to determine the WACC.

Table 5.1 below sets out the long-term credit rating for four Australian transmission and distribution gas companies that meet the criteria and have been assigned a credit rating from ratings agency Standard and Poors.[180]

Table 5.1: Credit rating associated with stand-alone energy companies

Company	Long-term rating
GasNet Australia	BBB
Envestra Ltd	BBB
AlintaGas	BBB
AGL	A

Source: Standard and Poors website (www.standardandpoors.com.au), June 2002.

On the basis of the data, the average credit rating of these entities was determined to approximate BBB+.[181] The data were corroborated by analysis undertaken by financial

[180] A stand-alone entity may be 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 18 per cent of Envestra Ltd is owned by Cheng Kong Infrastructure Holdings (Malaysia) Ltd and another 18 per cent is owned by Origin Energy Ltd (source: http://www.envestra.com.au). Further, 45 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).

[181] Recent evidence suggests that with the exception of Envestra, the gearing ratio of the companies used to calculate the benchmark are within a 10 per cent range of the 60:40 benchmark rate (Envestra has a gearing ratio of about 80 per cent (www.envestra.com.au)).

market experts. Accordingly, the Commission considered that a BBB+ credit rating represents an appropriate proxy credit rating for the benchmark company.[182]

The Draft Decision used this benchmark credit rating to determine the appropriate benchmark interest margin. It was noted that debt is raised by asset owners either through bank markets or through the private and public capital markets, but that requirements have primarily been met by the bank market for projects involving construction in Australia.[183] It was also noted that the interest margin associated with bank issued debt is generally lower than capital market interest margins. However, information on the debt margin associated with bank issued debt is generally not widely available. The Commission therefore considered that it is reasonable to use capital market data as the basis of the benchmark debt margin calculation, even though it may provide a benchmark which is biased in favour of the service provider.

In the Draft Decision the Commission referenced two sources in order to estimate the interest margin prevalent on Australian capital markets: data supplied by ABN Amro on specific bond issues and CBASpectrum data referenced on the Standard and Poors Australian website (www.standardandpoors.com.au). According to ABN Amro, bonds maturing in approximately five years (March 2007 and October 2007) exhibited a spread of between 125 and 129 basis points above government bonds,[184] while according to CBASpectrum the spread over the government bond yields for BBB+ corporate bonds with a maturity of five years was 132 basis points.[185] Thus, the Commission decided that it was reasonable to infer that the debt margin for BBB+ bonds with maturity of five years was likely to be in the range of 125-132 basis points. In light of the evidence at hand, it was proposed that a debt margin of 130 basis points would be reasonable, but that the Commission would continue to monitor capital markets for further evidence that the debt margin for a benchmark BBB+ entity is increasing or decreasing. The Commission proposed adjusting this figure for the Final Decision to reflect the latest available data at that time.

For the Draft Decision, it was considered appropriate to add an 8 basis points margin for prudent debt raising costs to the debt margin facing GasNet (refer section 6.2.1 of the Final Decision). Thus, the effective debt margin used in the calculation of the WACC for GasNet was 138 basis points.

Response to Draft Decision

In its submission to the Draft Decision, GasNet addressed the debt margin issue in combination with the topic of debt raising transaction costs. With regard to the benchmark debt margin, GasNet accepted the use of a BBB+ benchmark rating on the basis of current market evidence.[186] GasNet, however, argued that it is misleading to

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182 Some of these companies have non-regulated activities, which all else being equal, should lower the overall credit rating. Therefore, the rating for a 100 per cent regulated benchmark company would generally be higher than the benchmark determined above.

183 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, Report for the ACCC, May 2002. p. 7.

184 ABN Amro Fixed Rate Ratesheet Credit, 5 July 2002.

185 CBASpectrum data cited at www.standardandpoors.com.au

186 GasNet submission, 20 September 2002, p. 16.

assume that bank debt is less expensive than debt raised on capital markets. Furthermore, it asserted that it cannot be assumed that bank debt is readily available at benchmark margins, either on reasonable terms and conditions or at all. GasNet argued that stand-alone companies without a cornerstone investor are often the least attractive companies to lend to.[187]

With regard to the tenor of loan agreements, it asserted that borrowers must mitigate refinancing risk by spreading the maturity of loans entered into. GasNet argued that refinancing risk emerges from thin capital markets in Australia in combination with demand for finance from other regulated entities operating on the same review cycle.[188]

While GasNet disputed the bank debt and five year tenor assumptions proposed by the Commission, it did not explicitly criticise the general approach and the debt margin proposed by the Commission in the Draft Decision.

The EUCV claimed in its submission that a debt margin of 1.20 percentage points adequately compensates the service provider for 'debt acquisition costs'.[189]

Final Decision

The Commission intends to maintain its proposed approach to determining the debt margin as set out in the Draft Decision. As noted above, the basic premise of this approach is that the cost of debt should be calculated through reference to a debt margin for an appropriate benchmark entity.

With regard to the issue of the appropriate benchmark credit rating, as stated above, GasNet accepts the Commission's position in the Draft Decision that BBB+ is a reasonable assumption. The Commission notes that the credit ratings of the stand-alone companies outlined above remain unchanged as at the time of writing. Accordingly, it is proposed that BBB+ is kept as the benchmark credit rating for the purposes of the GasNet Final Decision.

With regard to the actual debt margin chosen, a number of concerns were raised by GasNet in relation to approach adopted by the Commission.

Firstly, as outlined in the Draft Decision debt requirements have primarily been met by the bank market for construction projects in Australia. Further, it stated with regard to debt raising costs (see section 6.2.1) bank financing represents the norm or benchmark for infrastructure financing. In its response to the Draft Decision GasNet argued, however, that 'it is misleading to assume that bank debt is readily available to a benchmark company'.

On further consideration the Commission is of the view that it may not be appropriate to assume a benchmark of bank debt. While debt requirements have primarily been

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187 ibid., pp. 16-17.

188 ibid., p. 17.

189 EUCV, 13 September 2002, p. 6.

met by bank markets for projects involving construction in Australia,[190] evidence suggests that energy infrastructure assets also obtain funds from private and public capital markets. It must be noted, however, that the Commission considers that the benchmark adopted should not incorporate funds raised on capital markets through ‘credit wrapping’. The Commission has not been provided with any evidence that a BBB+ benchmark Australian service provider cannot obtain debt from traditional bank and/or capital market sources.[191]

Secondly, the assertion in the Draft Decision that the interest margin on bank issued debt is generally lower than capital market interest margins was also disputed by GasNet. The Commission has undertaken further research relating to debt and capital markets and now concurs with GasNet that it is difficult to determine whether bank debt is less or more expensive than debt raised on capital markets. The Commission understands that there exists a range of different bank/capital market debt facilities and that the choice of arrangement is a function of a number of disparate variables. Nonetheless, it is considered reasonable to maintain the use of data from capital markets as the basis of the debt margin calculation, not least because such data are publicly available and are transparent to all interested parties.

Thirdly, GasNet asserts that borrowers must mitigate refinancing risk by spreading the tenor (or duration) of facilities issued, thereby inferring concern with the five year debt assumption used for parameter determination. The Commission reiterates its objective to abstract from the specific financing activities undertaken by the service provider. The five year debt assumption is considered appropriate because it matches the length of the regulatory period and should therefore reflect market expectations of rates over that period. In addition, evidence provided by Macquarie Bank suggests that debt issued by projects tend to have a five year tenor on average.[192]

In the Draft Decision the Commission used data supplied by ABN Amro on specific bond issues and CBASpectrum data on corporate bond spreads developed by the Commonwealth Bank as the basis of the debt margin calculation. It is considered appropriate to maintain this approach for the purposes of the Final Decision.

The table below summarises the spreads above the Commonwealth risk-free rate for publicly traded BBB+ corporate bonds on 5 July (used for the Draft Decision) and 27 September 2002. As the table illustrates, the debt margin has increased between that period for the majority of BBB+ issued bonds.[193] In particular, spreads for the BBB+ bonds maturing in approximately five years have increased from 124.5 and 128.5 basis points in July to 127.5 and 143.5 basis points in September respectively.

190 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, Report for the ACCC, May 2002. p. 7.

191 In a letter of 3 October 2002 from Westpac Institutional Bank to ElectraNet SA, it is noted that the domestic bond market will currently take up to $250 million for a BBB+ rated entity for a term of five years.

192 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, Report for the ACCC, May 2002, p. 22.

193 Reference to 27 September 2002 corporate bond data has been made as this date falls within the 40 day moving average period used to determine the risk-free rate parameter.

Table 5.2: Australian corporate bonds issued

BBB+ company	Maturity	Spread above government bonds 5 July 2002[a]	Spread above government bonds 27 September 2002[a]
Coles	September 2003	74.5	86.0
Ford	August 2003	129.5	276.0
Qantas	October 2003	84.5	92.0
Ford	March 2004	137.0	336.5
DOT	April 2004	78.0	84.5
DDT	September 2004	88.0	93.5
Coles	July 2005	90.5	131.0
Fairfax	July 2005	88.5	111.0
Southcorp	August 2006	109.0	104.5
SunMet	September 2006	118.0	116.5
Origin Energy	March 2007	124.5	127.5
Qantas	October 2007	128.5	143.5
Southcorp	March 2010	139.5	147.0

Source: ABN Amro, 5 July 2002 and 27 September 2002.
Note: (a) Benchmark spread above Commonwealth Government Securities with matching maturity.

The increase in corporate bond yields and spreads is corroborated by the data published by CBASpectrum. In the Draft Decision, reference was made to CBASpectrum data on one specific day. It is now considered more appropriate to measure the CBASpectrum debt margin data by taking an average of the spread over the same period used to determine the risk-free rate (40 business days). Such a measurement approach should limit any market aberrations that may come through in the data given thin corporate bond markets. This approach echoes the methodology adopted by the ESC in its recent Final Decision on gas distributors.[194]

Using this methodology, the average debt margin for the 40 business day period ending 11 October 2002 according to CBASpectrum data for BBB+ bonds with five year maturities was 146 basis points.[195]

In short, according to raw corporate bond data and information provided by CBASpectrum, the spread above the risk-free rate for five year BBB+ corporate bonds lies in the range 127.5 to 146 basis points. Given uncertainty and lack of comprehensive benchmark information relating to bank debt margins (as opposed to capital debt corporate bond margins provided here), the Commission considers it

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194 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 141.

195 This calculation is based on an average corporate bond yield of 6.7997 per cent and an interpolated government bond rate of 5.3369 per cent. The interpolated government yield differs slightly from the risk-free rate calculated over the same period given the adoption of a global interpolation by CBASpectrum, as opposed to the local linear interpolation used by the Commission. It was considered appropriate for consistency purposes to use the CBASpectrum corporate bond data to measure bond spreads.

appropriate to use the upper end of this range for the purposes of this Final Decision. Therefore, it considers that 146 basis points represents an appropriate market estimate of the debt margin currently on offer for a benchmark service provider.[196]

The Commission considers that the above approach to establishing the debt margin is cogent, transparent and consistent with the determination of the other WACC parameters. Through reference to current market evidence, it is considered that this approach promotes the service providers legitimate business interests and investment (section 2.24(a) of the Code) and promotes the economically efficient operation of the covered pipeline (section 2.24(d) of the Code). Through reference to market data and thus mimicking competitive markets, the Commission considers that the approach promotes the public interest, including the public interest in having competitive markets (section 2.24(e)). While a higher margin may negatively impact on users, no persuasive arguments were provided by interest parties as to why market evidence should be substituted for other assessments of an appropriate debt margin (section 2.24(f) of the Code).

As proposed in the Draft Decision, it is considered appropriate to add to the debt margin a number of basis points for prudent debt raising costs facing a benchmark service provider. As outlined in section 6.2.1, the Commission has decided that 12.5 basis points represents an appropriate margin for debt raising costs given current financial market conditions. Thus, the effective debt margin used in the calculation of the WACC for GasNet is 158.5 basis points.

5.5.3 Market risk premium

The rate of return determined for the PTS and WTS in 1998 included a market risk premium estimate of 6.0 per cent.

GasNet has argued that 6.0 per cent remains appropriate for the calculation of the rate of return for the forthcoming access arrangement period.[197] GasNet provided a paper it commissioned by NECG to support its proposal.[198]

As noted in the Draft Decision, the NECG paper reviewed market risk premium estimates for Australia based on historical data and stated that there is support for an estimate in the range of 6.0-8.0 per cent.

The Commission requested Dr Martin Lally to assess various approaches to, and estimates of, the market risk premium. Lally determined that the average estimate for Australia was 6.1 per cent and noted that although many empirical estimates of the market risk premium were available they diverged significantly and there is no clear consensus value. He concluded that ‘all of this suggests that the ACCC’s currently

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196 This market estimate is also supported by information from financial institutions which is attached to a submission to the Commission by ElectraNet SA dated 11 October 2002. National Australia Bank recommends a current spread above Commonwealth government bonds of between 144 to 149 basis points, Westpac a spread of 143 basis points and ANZ a spread of 132 basis points (excluding fees) for BBB+ entities.

197 GasNet submission, 27 March 2002, pp. 55-57.

198 NECG, *Market risk premium*, 23 November 2001 (GasNet submission, 27 March 2002 annexure 2).

employed estimate of .06 is reasonable, and no change is recommended'.[199] Accordingly, the Commission proposed to use 6.0 per cent as its estimate of market risk premium in the Draft Decision.

In response to the Draft Decision Amcor and PaperlinX referred to a paper prepared by Mercer Investment Consulting (MIC) which suggested that the market risk premium of companies listed on the Australian stock exchange is half that estimated for GasNet. The submission stated:

> We consider that the GasNet risk profile must be less than that of industries in a competitive environment and so the ACCC should reduce the MRP to reflect risk levels applying in a competitive environment.[200]

GasNet also provided a paper that it commissioned from Ernst & Young which included comments relating to market risk premium. Ernst & Young noted that regulators have estimated a value for the market risk premium with regard to historical measures. Ernst & Young stated:

> In the Officer approach, ten year average returns to the market are compared directly with ten year government bond rates. It is an empirical as opposed to theoretical issue as to whether the market risk premium will change if the measurement interval is reduced to five years for consistency with the regulatory period. Ernst & Young has not performed this analysis but anticipates higher volatility in the annual market risk premium measures and therefore anticipates a movement from the Officer study levels.[201]

The paper from MIC referred to by Amcor, PaperlinX and EUCV was prepared for the ESC. MIC noted that while it does not generally provide advice on market risk premium to clients, an implied ex-ante premium could be determined from its forecast of returns for Australia shares over the next 10 years. As a result, MIC derived an estimate of the market risk premium of 3.0 per cent. While MIC noted that this is much lower than estimates derived from historical data, it did not argue that one method is more correct than the other. In fact, MIC considered that there is considerable divergence of opinions in regard to estimating the market risk premium and 'there is as yet no emerged consensus'.[202]

The ESC draft decision included a detailed discussion on the market risk premium. Having regard to all the information before it, including the MIC paper, the ESC adopted an estimate of the market risk premium of 6.0 per cent.[203] While the gas distributors expressed concern at this outcome, and the ESC's analysis, the ESC adopted the same value in its final decision, concluding:

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199 M Lally, *The cost of capital under dividend imputation*, June 2002, p. 34. A 6 per cent MRP has also been endorsed by Professor Officer: 'Trends in market risk premium' presentation to the open forum 'Key WACC issues in the regulation of electricity and gas transmission', 24 June 2002.

200 Amcor and PaperlinX submission, 13 September 2002, p. 10. EUCV also referred to this paper: EUCV submission, 13 September 2002, p. 7.

201 Ernst & Young, *Review of issues in the estimation of the risk free rate for regulatory purposes*, report prepared for GasNet Australia, September 2002, p. 11. (GasNet submission, 20 September 2002, Appendix A).

202 Mercer Investment Consulting, *Australian equity risk premium*, July 2002, p. 8.

203 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 225.

> The Commission [ESC] remains of the view that the weight of evidence discussed above provides 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. Indeed, the evidence discussed above (including the new information received since the Draft Decision) would suggest that many market practitioners would adopt an assumption about the equity premium that is lower than the assumption of 6 per cent that the Commission has adopted in previous decisions and in the Draft Decision.[204]

As indicated in the Draft Decision, the Commission has reviewed a number of works on the issue of determining an estimate of the market risk premium. The Commission concurs with Lally, MIC and the ESC that there is no clear consensus on the appropriate method or value for the market risk premium. Nevertheless, a point estimate is required for the CAPM and calculation of a rate of return. As a result, the Commission, like the ESC, has attempted to use an estimate that has reference to both historical data and forward looking information.

In determining an appropriate estimate of the market risk premium for this Final Decision the Commission has carefully considered the additional information provided in recent submissions. In addition, the Commission has considered GasNet's legitimate business interests pursuant to section 2.24(a) of the Code. The Commission acknowledges the studies that suggest that the appropriate estimate of market risk premium is less than the 6.0 per cent the Commission has generally used to date in its regulatory decisions. However, the impact of altering the estimate at this time to 3.0 per cent, for example, may be unduly harmful to GasNet's legitimate business interests.

On balance, in light of the information available at this time and the requirements of the Code, the Commission does not consider that it would be appropriate to move from the value of the market risk premium adopted in its Draft Decision. Accordingly, for the calculation of the benchmark rate of return for the GasNet access arrangement, the Commission has adopted a market risk premium estimate of 6.0 per cent.

5.5.4 Gearing

The rate of return for GasNet's access arrangements was determined on the basis of a gearing ratio of 60:40 (debt:equity). Service providers have frequently proposed this ratio. In addition, the Commission and other regulators have often recommended this ratio as an appropriate benchmark for regulated entities.

GasNet proposes to continue with this gearing ratio for the forthcoming access arrangement period. The Commission has not received any comments to suggest that the proposed gearing ratio is inappropriate and should be altered. The Commission considers that a ratio of 60:40 is appropriate and has adopted it in its calculations of the benchmark rate of return for this Final Decision.

5.5.5 Imputation credits

As noted earlier, the model used by the Commission to assess forecast regulated revenues is based on investor post-tax return requirements estimated using the CAPM.

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[204] ESC, *Final Decision: review of gas access arrangements*, October 2002, p. 336.

To ensure a reasonable expectation of achieving the benchmark return, tax compensation is added as a separate element in these forecast revenues. The forecasting of tax payments is the first stage in calculating the amount of compensation for tax.

Another factor of critical importance for providing an appropriate level of compensation for tax is that, under the system of dividend imputation, Australian shareholders are able to receive a credit for tax paid at the company level when determining their personal income tax. The standard practice amongst Australian regulators and finance practitioners is to treat this benefit as an offset to the particular entity's company taxation liability.

The assumed value of imputation (or franking) credits is usually expressed as a proportion of their face value, with this proportion denoted by gamma (γ). This approach implies that if a regulated entity were assumed to pay \$X in company tax in a particular year, then the regulated entity would only require an allowance of \$(1-γ)X for taxation compensation. The remaining \$$\gamma$X would be provided directly to shareholders through the imputation system.

This interpretation of gamma holds regardless of whether the value of franking credits is reflected in the (pre-tax) WACC or in the cash flows. It is in this sense that gamma is one of the key CAPM and WACC parameters. The gamma also has a minor role in the levering formula used by the Commission to determine the equity beta from the asset beta. This formulation for the equity beta developed by Monkhouse requires the inclusion of gamma as a consequence of an assumption in its derivation that the company (consistent with the regulatory framework) has an active debt management policy aimed at maintaining a particular gearing ratio. 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 depends on whether franking credits are made available to investors by attaching them to dividend payouts from the firm and whether the investor is fully able to utilise the value of the credit. For an Australian investor:

- there appears no logic or benefit in the company retaining such credits any longer than necessary; and
- recent changes under the new tax system allow the benefit to be received by Australian taxpayers as a rebate.

Empirical observation of the behaviour of Australian firms confirms the first of these points, and together with the second point, strongly suggests the value of gamma used in the regulatory framework should be 1.0.[205]

However, GasNet has argued for a value of gamma of 0.5 to be consistent with previous regulatory decisions and to reflect the fact that, in its view, many owners of pipeline operations in Australia are not Australian taxpayers and do not benefit to the

205 The evidence for payout of imputation credits is discussed in M Lally, *The cost of capital under dividend imputation,* a paper commissioned by the ACCC, April 2002.

full extent from the Australian tax imputation system. It further points out that empirical studies based on share movements when shares go ex dividend are consistent with a gamma value closer to 0.5 than 1.0.

This last point is to be expected when a significant portion of the shareholder base is not subject to Australian taxation. However, the observation is essentially irrelevant to the regulatory framework which consistently maintains the assumption that the equity investor is domiciled in Australia. This allows for consistency in applying the CAPM in the context of the Australian market and the fact that regulated services are provided to the Australian market. If the assumption were to be relaxed, it is not sufficient to merely adopt a different value of gamma. Instead, the whole CAPM framework would need to be revised to recognise the international context in which the foreign investors are operating. As a first step this involves the adoption of an international version of the CAPM model and reconsideration of the relevant CAPM parameters. Lally considers this issue in detail and provides strong evidence to show that reducing the value of gamma as a means of recognising the existence of foreign investors provides a perverse result.[206] Instead, his analysis shows that the costs of capital for foreign investors is somewhat less than their Australian counterparts and that setting gamma to 1.0 would not compromise the benchmark returns they require if their foreign status is fully considered.

Notwithstanding the strong evidence for a gamma value of 1.0, for the purpose of this Final Decision, the Commission has decided to retain an assumed value of gamma equal to 0.5 consistent with what was approved for the initial access arrangement period and other recent regulatory decisions. This maintains a sense of regulatory consistency and represents one of the concessions aimed at ensuring that the rate of return is not too low for the ongoing operation of the business. However, in future decisions, after the Lally analysis has been subjected to further debate, the Commission retains the option of revising the gamma parameter value to be more consistent with market evidence.[207]

5.5.6 Effective tax rate

The effective tax rate (T_e) is by definition a parameter which links the relationship between the post-tax return on equity (r_e) determined by the CAPM and the pre-tax return on equity (r_{te}) emerging from regulated cash flows.

$$r_e = r_{te} \times (1 - T_e)$$

The parameter is not required as an input to the post-tax framework for the determination of regulated revenues as described above except for an insignificant role in the calculation of the equity beta using the Monkhouse formula. The calculation of the tax compensation in the post-tax framework is based on estimated benchmark tax

206 M Lally, *The cost of capital under dividend imputation,* a paper commissioned by the ACCC, April 2002.

207 Such revisions may not only involve gamma but also a revision of the CAPM framework to better recognise the status of foreign investors in Australian regulated infrastructure. The Commission considers that a working assumption that the average investor is an Australian entity remains a practical and fair approach.

payments and not an assumed long term average rate of tax on returns. However, using the above relationship an effective tax rate can be calculated by simulating cash flow expectations over the life of the asset. Essentially, it is an outcome from the regulated cash flows rather than an input. As a result of the deferral of tax payments well into the future the impost of tax is well below the current corporate company tax rate of 30 per cent. Simulations of the cash flows over 36 years (the average remaining life of the regulated assets originally proposed for the access arrangement) suggest that the effective tax rate for GasNet lies between 6 and 8 per cent. The number can only ever be approximate since the future impost of tax legislation is unknown and is usually approximated by assuming that existing tax rules are maintained.

5.5.7 Beta

Draft Decision

Systematic risk is accommodated in the CAPM framework by the equity beta (β_e). This indicates the riskiness of one asset or project relative to the whole market (usually represented by the stock market). An equity beta greater than one indicates that the asset or project has returns that are expected to have more variability than the market average. This risk cannot be eliminated through a well balanced and diversified portfolio (unlike specific risk).

To compare the risk associated with a number of businesses independent of their financial structure (gearing), equity betas are 'de-levered' to produce asset betas (β_a). While there are a number of levering formulae, the Commission consistently applies the formula developed by Monkhouse:[208]

$$\beta_e = \beta_a + (\beta_a - \beta_d)\left[1 - \left(\frac{r_d}{1+r_d}\right)(1-\gamma)\,T_e\right]\frac{D}{E}$$

The Commission determined that the appropriate asset beta for the initial PTS and WTS access arrangements was 0.55 (with a corresponding equity beta of 1.20). This value was selected following advice from experts that the Commission could accommodate some specific risks, such as self-insurance and other asymmetric costs, identified by the applicant through a beta 'towards the top end of the plausible range'. In addition, it was suggested that the value of the beta should reflect the applicant's view that revenue or price cap regulation is more risky than rate of return regulation and that the new regulatory regime introduced perceived uncertainties for investors.[209]

GasNet considered an asset beta of 0.60 to be appropriate for its business for the forthcoming access arrangement period and has adopted this in its CAPM calculations. With a debt beta of 0.06, based on previous Commission decisions, GasNet has calculated an equity beta of 1.40.[210]

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208 See ACCC, DRP, May 1999, pp. 79-81.

209 ACCC, 1998 Final Decision, pp. 59-61.

210 GasNet access arrangement information, 27 March 2002, p. 6.

GasNet commissioned a report by NECG regarding beta.[211] NECG noted that due to the limited period that GasNet has been a listed company a direct measure of an asset beta for the business is not possible. Accordingly, NECG proposed that the 'method of similars' be used to determine an approximate asset beta for GasNet. Four sources of information were used by NECG in this process.

First, a number of earlier Australian regulatory decisions relating to gas and electricity infrastructure were considered. From this information NECG suggested that an appropriate range for gas transmission assets is 0.50-0.60.

Second, NECG considered data from a recent Queensland Competition Authority (QCA) regulatory decision on electricity distribution, which provided beta estimates for a number of energy businesses. Data on Allgas, AGL and United Energy provided an asset beta range of 0.42-0.47 and an average of 0.44.

Third, available data for comparator businesses were considered. Equity beta data from the Australian Graduate School of Management (AGSM) risk management service were de-levered by NECG, according to the Monkhouse formula, to obtain asset beta estimates. The companies used were AGL, Energy Developments, Envestra and United Energy. NECG regarded AGL and United Energy as the closest comparators and, as a result, concluded that the relevant range is 0.47-0.51 for the asset beta.

Fourth, equity beta data from the Dow Jones Interactive website were used to estimate asset betas for several companies. NECG regarded AGL, Origin Energy, Energy Developments and United Energy as the most relevant comparators (it excludes AlintaGas, APT and Envestra), resulting in a range of 0.50-0.63.

NECG concluded that a plausible range for an asset beta of a gas transmission company would be 0.45-0.65. It stated that the appropriate value for GasNet in this range would be influenced by a number of factors including regulatory arrangements, the possibility of bypass and correlation of gas demand with economic activity and size. In addition, NECG considered that the industry is becoming an 'increasingly competitive and volatile environment for gas transmission companies' and that 'the inevitable conclusion therefore is that, GPU GasNet is likely to be entering a period of higher systematic risk'.[212]

GasNet reiterated NECG's view that the business has some distinctive features that indicate that it is particularly sensitive to changes in GDP, which implies a higher asset beta. These features are:

(a) GasNet is regulated under a price cap regime, which exposes GasNet to full volume risk (electricity transmission companies, for example, generally operate under a revenue cap which removes volumes risk);

(b) the GasNet tariff structure is linear, in contrast to the two-part tariff often used on distribution networks and contract carriage transmission pipelines, which results in GasNet having a greater exposure to volume risks; and

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[211] NECG, *Asset, equity and debt beta*, 4 January 2002 (GasNet submission, 27 March 2002 annexure 5).

[212] ibid., p. 20.

(c) under the Service Envelope Agreement and MSO Rules GasNet is “locked in” to a market carriage regime and does not have significant revenues secured under take or pay contracts, as is the norm on contract carriage gas transmission systems.[213]

GasNet argued that these features have had a very real impact on the business during its initial access arrangement period. GasNet’s volumes have been significantly lower than those forecast (and used to determine reference tariffs) and have resulted in a revenue shortfall that is expected to exceed $19.3 million.[214] These events, according to GasNet, indicate that the current asset beta of 0.55 is ‘understated’ and support its argument that the asset beta should be 0.60.

In contrast, Origin considered that the beta for the forthcoming access arrangement period should be less than the current value because the revised demand forecasts are based on more conservative assumptions, reducing GasNet’s exposure to the volume shortfalls than it experienced in the initial access arrangement period. It also considered that the amended operation of the K factor reduces the need for a high beta. Origin concluded that there are ‘no unique circumstances applying in the forthcoming period that are consistent with GasNet claiming a higher asset beta (and therefore a higher pre-tax real WACC) than the previous access arrangement’.[215]

Amcor and PaperlinX considered that GasNet has moved risks relating to volume, asymmetrical events and pass through events onto users. By not accepting these risks, which would be carried by businesses operating in a competitive environment, GasNet has reduced its risk profile and should receive a lower return.[216]

EnergyAdvice noted that, if implemented, the proposed tariff design will result in a greater proportion of revenues recovered from volume based charges compared to the peak day charges. This change increases the risk exposure of GasNet’s revenue. EnergyAdvice questions whether it is reasonable for users to pay higher tariffs (due to a higher rate of return) as a result of GasNet compounding its risk.[217]

A report prepared for the Commission by ACG regarding beta included some responses to NECG’s report. First, of the four sources of information used by NECG, ACG regarded three as not being independent. Instead it considered them to be different calculations or approaches using the same primary information source from the AGSM. The Commission agrees with ACG’s view that:

> The use of a widely available and frequently-updated beta estimation service also permits the same beta estimation methodology to be used across decisions and industries, and thus reduce the uncertainty associated with the regulatory process. ... By committing to use a credible, independent source for beta estimates, the likelihood that regulators or regulated entities may seek (or appear to seek) to cherry-pick the methodological choices to produce their desired

213 GasNet submission, 27 March 2002, p. 64.

214 The Commission understands that the majority of this total is recoverable through the average price control mechanism. GasNet response to Commission, 1 August 2002.

215 Origin submission, 17 May 2002, p. 7.

216 Amcor and PaperlinX submission, 24 June 2002, p. 23.

217 EnergyAdvice submission, 30 May 2002, p. 9.

> result should be reduced and thus reduce the uncertainty and controversy associated with price reviews.[218]

Second, ACG raised concerns regarding the businesses included in NECG's derivation of beta for GasNet using the comparator business approach. It did not agree with NECG's exclusion of Envestra (a gas transmission and distribution business with the majority of activities under price cap regulation). In addition, ACG did not agree with the inclusion of Energy Development (whose business is largely electricity generation) and Origin (which carries out gas production, gas and electricity retailing and LPG supply).

In addition, ACG questioned NECG's assertion that the Commission had implicitly adopted the 'Blume adjustment' to beta data. It also expressed concern regarding NECG's comments on the relationship between asymmetric risk and CAPM and the relative risk of GasNet's business. ACG noted that the NECG had not disclosed the assumptions it made regarding the debt beta.

ACG undertook an assessment of beta for Australian gas transmission businesses. Using data from the AGSM, ACG considered that the data imply an equity beta estimate of 0.7.[219] ACG also considered data for comparable businesses in the US, Canada and UK. These data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. ACG stated:

> 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.[220]

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of one. ACG noted:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[221]

The Commission considered the information provided by various parties in regard to beta estimation for the Draft Decision. It expressed concern with some aspects of GasNet's NECG report (such as the selection of comparator companies) as noted by ACG. It also considered GasNet's views on its 'distinctive features' that are said to support a high beta. The Commission stated that it did not consider that these features relate to the systematic risk of the business and consequently, should not impact on

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218 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 46.

219 The result of 0.7 reflects calculations for the equity beta for Australian gas transmission businesses that result in a range of 0.66 to 0.69. The calculations assumed a debt:equity ratio of 60:40 and used data from AGL, Australian Pipeline Trust, Envestra and United Energy. Variables included excluding and including tax from the re-levering formula and a debt beta of either 0 or 0.15. ibid., pp. 39-41.

220 ibid., p. 42.

221 ibid., p. 43.

beta. In particular, it should be noted that GasNet is regulated under an average revenue control mechanism, and not a price cap as suggested.

The Draft Decision acknowledged that the beta estimate adopted in the 1998 Final Decision accommodated some aspects of specific risk. However, the Commission has worked to refine its approach to beta, and CAPM in general, subsequent to that decision. It did not consider it appropriate to continue with these ad hoc adjustments merely because they were carried out in the past. In particular, it did not consider that an adjustment for the uncertainty due to the 'newness' of the regulatory regime (a non-systematic risk) was appropriate any longer.

The Commission also considered whether the business has changed such that its risk relative to the market in general has fundamentally changed since 1998. It concluded that there was no available evidence that the systematic risk of GasNet had changed significantly.

The equity beta estimate used in the 1998 Final Decision was 1.2. Such a figure would indicate an expectation that the business would experience greater volatility than the market in general. This did not appear to be consistent with the widely held view that gas, and electricity, utilities are less risky and more stable than the market average. Greater stability suggests that the equity beta should be less than one.

The Commission considered the information presented by GasNet as well as other interested parties in its assessment of the appropriate asset beta for the business. In particular, it referred to the report prepared by ACG which indicated that the current appropriate asset beta for Australian gas transmission businesses may be between 0.27 and 0.37.[222] However, for the reasons indicated by ACG in reference to the equity beta as noted above, the Commission considered that it may be premature to rely on market data exclusively when determining the asset beta. Accordingly, the Draft Decision proposed an asset beta (β_a) of 0.5 for GasNet.

The upper limit to the debt beta (β_d) can be determined from the formula:

$$\beta_d = \frac{r_d - r_f}{MRP}$$

With the Draft Decision proposed values for the relevant parameters, the calculation results in a debt beta of approximately 0.23. However, work undertaken by the ESC concluded that the debt beta is likely to be between 0 and 0.18 although a value toward the upper end of this range was more likely.[223] ACG has also considered this information and suggested that an appropriate range for the debt beta would be between 0 and 0.15.[224] The value 0.15 is the estimate obtained using the same modified equation for the debt beta used in the 1998 Final Decision. That is:

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222 ibid., p. 40.

223 ESC, *Draft Decision: review of gas access arrangements*, July 2002, pp. 231-233.

224 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, pp. 28-29.

$$\beta_d = \frac{r_d - r_f - r_c}{MRP}$$

where r_c was set to 0.0048 to reflect that component in the interest rate margin (for example, transaction costs) unrelated to systematic risk (default risk for the lender).

On balance, the Commission considered that an appropriate value for the debt beta for the Draft Decision was 0.15.

Accordingly, through the application of the Monkhouse formula noted above, the equity beta for GasNet was set at 1.0 for the Draft Decision.

Response to Draft Decision

In response to the Commission's Draft Decision, EUCV stated:

> We are at a loss to understand why the ACCC would consider that GasNet could ever be seen as an "average risk" company. With microscopically little competition and such consistent demand for the product it carries, this puts GasNet into a very low risk business.[225]

BHP Billiton noted GasNet's concerns regarding the equity beta and stated:

> ... an equity beta of 1.0 replicates the average of all competitive industries. As GasNet operates in a comparatively secure environment, its equity beta should be lower than unity, reflecting its place in the "pecking" order of risk faced by all businesses.[226]

In contrast, AusCID noted that the WACC proposed in the Draft Decision is lower than that in the 1998 Final Decision and stated that it 'is based on an equity beta that is considerably lower than that approved for a recent pipeline project'.[227]

NECG provided a submission in response to the ACG report prepared for the Commission regarding beta. It raised a number of points:

- beta estimates are volatile over time, exposing regulated companies to a risk that cannot be hedged. Thus, caution must be exercised in beta estimation;
- although ACG highlighted the merits of using beta estimates derived from the same beta estimation methodology, it then made use of data sourced from Ibbotson, LBS, AGSM and Bloomberg;
- ACG criticised the exclusion of Envestra from NECG's initial beta sample. However, the QCA also excluded Envestra. In NECG's view 'Envestra's highly unusual capital structure still presents a significant risk of biasing beta estimation';[228]
- NECG's use of the Blume adjustment reflected its view on regulatory practice at the time regarding the imprecision associated with beta estimates; and

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225 EUCV submission, 13 September 2002, pp. 6-7.

226 BHP Billiton submission, 11 October 2002, p. 22.

227 AusCID submission, 12 September 2002, p. 2.

228 NECG submission, 13 September 2002, p. 8.

- ACG claimed that any gas sold to Victorian households would travel though the PTS. However, users on the WTS may be supplied from the proposed pipeline between Port Campbell and Adelaide to be built by South East Australia Gas (SEA Gas) Pty Ltd (SEA Gas pipeline) in the future and this impacts on GasNet's diversified and undiversified risk.

GasNet also commented on the Commission's use of the ACG report, stating 'that the Commission has incorrectly interpreted the findings contained in the ACG paper. In our view, the recommendations of the paper support a beta of at least 1.2 for GasNet'.[229] Furthermore, GasNet stated that 'on the basis of a fair reading of the ACG paper, GasNet considers that the empirical evidence is not available to support an estimate of the equity beta'.[230]

In addition, GasNet argued that the proposed beta in the Draft Decision moves away from previous regulatory decisions. It noted, in particular, the Commission's July 2002 Final Approval regarding the Moomba to Adelaide Pipeline System which 'approved a beta of 1.16'.[231]

It also stated that the Commission has not had regard to its legitimate business interest 'in ensuring that a reasonable equity beta is maintained'.[232]

GasNet identified a number of other factors:

- the specific risks included in the 1998 Final Decision beta would have made negligible difference to the beta estimate adopted;
- the liberalisation of the K factor proposed in the Draft Decision which accounts for about half of the $19.3 million accrued revenue shortfall, is not a sufficient basis to lower GasNet's asset beta;
- it is not appropriate to compare GasNet with a traditional utility risk profile as 'the Victorian Government reform process has significantly increased the level of risk on infrastructure businesses in Victoria';[233]
- the view that an equity beta of 1.2 for a utility is inconsistent with market assessment that utilities are less risky than the market average is not correct and ignores the higher gearing of utilities;
- asset betas previously approved by the Commission have been lower than the asset beta of the market as a whole;
- the inclusion of an allowance for the newness of the regulatory regime in 1998 would have had little impact on the beta. The suggestion that an allowance is no longer needed conflicts with the Moomba to Adelaide Pipeline System decision; and

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229 GasNet submission, 20 September 2002, p. 18.

230 ibid., p. 20.

231 ibid., p. 19.

232 ibid., p. 21.

233 ibid., p. 22.

- regulatory risk lies in the volatility of regulatory philosophy over time and not in the initial decisions.

GasNet commissioned Ernst & Young to review the ACG report on beta. GasNet stated that the Ernst & Young analysis raises a number of concerns regarding methodology and data quality.

Ernst & Young acknowledged that where there are no directly comparable companies, somewhat comparable companies should be used to obtain an implied beta. It noted that of the businesses used in the ACG report, only APT obtains a significant portion of its revenues from gas transmission services.[234]

It also noted ACG's use of net debt, rather than total debt, to determine gearing of the comparator businesses. Ernst & Young suggested that the use of net debt figures results in understated estimates of asset betas. It also argued that ACG's use of simple averages of betas is not appropriate if there are outliers in the group or if the range of data is large. Ernst & Young suggested that a more appropriate measure would reflect the inter-quartile range of the data.[235]

Ernst & Young discussed the use of the Blume adjustment to equity betas. It noted that as empirical data indicate that Australian betas tend to move over time, an adjustment such as the Blume adjustment should be used. Ernst & Young stated that the overall effect of the Blume adjustment is to increase beta estimates that are below one.

ACG used data from the AGSM for the Australian comparator businesses. Ernst & Young noted that data obtained from Bloomberg provides different beta estimates for the same businesses. It stated that:

> ... under such circumstances it is difficult to place heavy reliance on the equity betas estimated and therefore even less reliance can be placed on asset betas inferred from the equity beta estimates.[236]

Ernst & Young also provided comments on the debt beta used by the Commission in the Draft Decision. It argued that the derivation of 0.15 places a heavy reliance on a single study that makes some significant assumptions. Ernst & Young raised a number of concerns with the assumptions and concluded that the study should not be applied to the Australian market. Consequently, Ernst & Young suggested that a debt beta calculated from the equation and parameters in the Draft Decision of 0.23 would be more appropriate for GasNet. It noted this would result in an asset beta of 0.538, for an equity beta of 1.0.[237]

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234 Ernst & Young *Critique of the approach adopted by the ACCC in estimating asset, debt and equity betas*, September 2002, p. 15 (GasNet submission, 20 September 2002, Annexure B).

235 ibid., p. 16.

236 ibid., p. 20.

237 ibid., p. 14.

Final Decision

The submissions provided to the Commission raise a number of concerns regarding the estimation of beta for GasNet. The conflicting views also indicate the difficulty in determining an estimate for a business.

The Commission acknowledges NECG's comment that beta estimates can be volatile over time. It agrees that this movement makes determining a single point estimate for a business a difficult task. However, it is not the objective of the Commission to identify a point estimate for a particular company. Rather the focus is on identifying a benchmark beta commensurate with the systematic risks faced by a company providing the types of service offered under the access arrangement proposal. To assist in this matter, the Commission has tended to review current beta estimates from AGSM for a range of comparable businesses, information from other regulators as well as reliable academic and other studies in the area. As with previous decisions, this approach was adopted for the Draft Decision.

The Commission and the ACG expressed concern that the selection of comparable Australian businesses by NECG excluded Envestra. The Commission acknowledges that Envestra has a somewhat unusual gearing structure.

However, the outlier status of Envestra seems to be overstated. For example, the QCA reported in a 2001 decision that Envestra had a gearing ratio of 83 per cent and commented that this was different to other companies.[238] Information available from company financial reports indicate that the current gearing for Envestra is 74 per cent while the gearing for GasNet is 69 per cent and APT has a gearing of 64 per cent.

NECG iterates a range of reasons for excluding Envestra from the sample of benchmark companies. However, for the reasons pointed out in the ACG report[239] there is no reason to believe that gearing or the other reservations expressed over the inclusion of Envestra in the sample of considered companies is likely to lead to biased estimates.

Also of some significance is the fact that since the Draft Decision the AGSM has released updated beta estimates for Envestra based on a longer time series of available data, thereby improving the statistical reliability of the estimates used.

The Commission acknowledges that the SEA Gas pipeline may be able to supply some users of the current WTS in the future. However, as the WTS volumes account for approximately two per cent of total volumes, the potential impact on GasNet's revenues is relatively low. In any event, the risk is specific and should not impact on the financial market uncertainty. Instead, the issue may be dealt with proposing prices adjusted by an adequate prudent discounting or by modifying forecasts of demand.

GasNet has commented that the Draft Decision beta has not considered the precedent of other Commission decisions and in particular notes the beta provided for the Moomba

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[238] NECG submission, 13 September 2002, pp. 7-8.

[239] ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, pp. 48-50.

to Adelaide Pipeline System (MAPS). However, GasNet does not acknowledge that the decision to which it refers is a Final Approval, not a Draft Decision or Final Decision. The Commission stated in its MAPS Final Approval:

> The Commission's *Final Decision* for the MAPS determined a proxy equity beta of no more than 1.16. As stated above, the Allen Report indicates that a proxy equity beta of around 1 errs in favour of the regulated entity. The Commission does not consider it appropriate to lower its assessment of the maximum proxy beta for the MAPS at this stage of the assessment process. However, it should be noted that if the Commission were to divert from the maximum proxy beta allowed in its *Final Decision* for the MAPS, it would be downwards in light of current market evidence, and not in the direction sought by Epic.[240]

GasNet states that the ACG report does not support a move in GasNet's equity beta from 1.2 (in the 1998 Final Decision) to 1.0 (proposed in the Draft Decision). This statement misrepresents the thrust of the ACG report, which noted that the latest Australian market evidence would imply a proxy equity beta of 0.65 or 0.7 (rounded up). In addition, overseas evidence suggests that such a value does not understate the beta risk of regulated companies.[241] The qualification expressed by ACG was that it would be at the discretion of the regulator to adopt a conservative approach and not make large adjustments to benchmark parameters in successive decisions. Accordingly, it suggested the adoption of a proxy equity beta of approximately 1.[242] That is the value the Commission selected in the Draft Decision. More recent beta estimates give no reason to believe that was not a conservative choice.

It should be noted that the Code makes it incumbent upon the Commission to adopt parameter settings relevant to current financial markets. Accordingly, when parameters used in the past have been found to be inaccurate or based on incomplete information there is a requirement to adjust the parameters. This is the situation with the beta estimate. For the 1998 Final Decision empirical estimates of betas were only available for overseas regulated companies. While these estimates were also consistent with an equity beta less than 1, the Commission chose a slightly higher value because of uncertainty associated with the newness of regulation in Australia. Now, four years further on there is sufficient market based data to confirm that perceived business risk facing Australian regulated companies is no greater than for their overseas counterparts.

Consistent with this approach, the Commission seeks to adopt parameter values that are neither high nor low. To do so might tend to damage the business interests of either the regulated firm or its customers. In this context the term conservative is used in the sense that adjustments of parameters will be a gradual process dependent on improving market-based evidence. Therefore, if the current best estimates of market based betas are re-confirmed in the future it is possible that over time the value used in regulatory decisions will converge to the statistical estimates based on comprehensive Australian financial market data.

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240 ACCC, *Final Approval: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 31 July 2002, p. 22.

241 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 42.

242 ibid., p. 43.

GasNet also suggests that the Commission has not taken its business interests into account when proposing an equity beta of 1.0. Based on current evidence it is unlikely that the relevant beta is greater than 1.0 and to use a value greater than 1.0 would give rise to a cost of capital estimate for GasNet which is greater than GasNet's actual cost of capital given the gearing assumptions.

In summary, the Commission rejects the claims made in GasNet's submission and associated attachments. In particular, it does not find any evidence to support a move in the equity beta from 1.2 to 1.4 as proposed by GasNet and considers that the ACG report provides a reliable account of recent market data which the Commission must consider when determining an appropriate value for beta. As discussed in the Draft Decision, the Commission considered GasNet's interests, by making a conservative adjustment of the relevant equity beta to adopt an equity beta of 1.0 rather than the 0.7 indicated by the empirical evidence. In the context of other parameters assumed, such as gearing and debt beta, an equity beta of 1.0 has been found to be consistent with an asset beta of 0.5. The asset beta relevant to an unlevered firm is, in a sense, the more fundamental measure of risk. This value of the asset beta has been used as the starting point for all subsequent cost of capital calculations.

GasNet has also suggested that it should not be compared to traditional utilities. The Commission acknowledges that it has compared GasNet's business with other regulated transmission pipeline businesses. As noted by GasNet, these businesses do not operate with a market carriage system. Consequently, the Commission has also referred to gas distribution businesses, particularly those in Victoria which also operate with a market carriage system and reflect the reforms implemented by the Victorian government.

Indeed, GasNet's response to the Draft Decision states that during the past access arrangement period it suffered a $19.3 million revenue shortfall to the end of 2001 precisely because of this volume risk.[243] This overstates the magnitude of the issue since more than half of this amount is attributable to a change in the demand mix which is carried forward and fully compensated for by adjustments to prices in subsequent years. The unrecovered component was essentially due to a systematic error in the demand forecasts for the initial access arrangement period. These forecasts were provided to the Commission by the service provider itself. GasNet is not expected to repeat the forecasting error for the forthcoming access arrangement period. While pipeline companies subject to contract carriage regimes have more certainty over existing customer revenues they are still subject to similar forecast uncertainty with respect to market growth and it is not clear that the magnitude of the problem is significantly different for such companies. In any event, as the ACG report points out:

> …it needs to be borne in mind that if primary reliance is placed upon objective market data when deriving a proxy beta, then the relevant matter is how the target entity (GasNet in the case of the NECG Report) differs to the firms in the group of comparable entities. With respect to the form of price control and the existence of contracts:
>
> - all of the Australian energy utilities are regulated under price caps (or average revenue caps), and none are regulated under revenue caps or rate of return regulation; and

243 GasNet submission, 20 September 2002, p. 22.

- only the Australian Pipeline Trust has a significant share of its revenue fixed under contracts – that is, the distribution activities of AGL, Envestra and United Energy all have a similar contractual situation to GasNet.

> In principle, the fact that most of the Australian comparable entities do not have contractual cover may suggest that the proxy beta derived from the group of Australian energy utilities would overstate their level of systematic risk. However, as discussed in section 4.3, we would caution against attempting to make ad hoc adjustments to proxy betas on account of perceptions of differences in non-diversifiable risk given the absence of empirical evidence on the size of the required adjustment (and whether any adjustment may be warranted at all).
>
> A more relevant concern with the use of the Australian energy utilities is that all of the companies except for Envestra undertake significant non-regulated activities, which would be expected to have higher systematic risk. Thus, the simple average of the betas across the proxy group is more likely to overstate the proxy beta for a pure-play regulated entity. Again, however, it is not considered that attempts should be made to adjust for such matters given the absence of empirical evidence on the size of the required adjustment. [244]

The Commission has also considered the impact of the pass-through mechanism that GasNet has proposed to operate from the start of the second access arrangement period. While the Commission has reservations about this departure from a pure price path approach, it acknowledges that the Code provides the service provider discretion in selecting elements of a cost of service approach (see section 3.3 of this Final Decision). As the Commission has accepted this approach, GasNet will enjoy a reduction in its risks compared to the initial access arrangement period and with other service providers (who operate under a pure price path approach).

Conclusion

The Commission has considered all the new material presented by GasNet in response to the Draft Decision and finds there is insufficient evidence to suggest the conclusions of the Draft Decision were in error. Therefore, the Commission has concluded that an asset beta of 0.5 is appropriate for GasNet at this time.

As the debt beta formula indicates, the debt beta will vary with the debt margin. As the debt margin increases so does the debt beta, reflecting the higher level of default risk perceived by the lending institution. Since the debt margin included in this Final Decision is different to the 1.38 included in the Draft Decision, the value for the debt beta calculated by the formula is different from the Draft Decision. It is now calculated to be approximately 0.18. This value has been incorporated into the CAPM for this Final Decision.

Following the Monkhouse formula, as noted earlier in this section, these parameters result in an equity beta of 1.0. The Commission considers this is appropriate for GasNet and has used this in the CAPM to determine a return on equity for the business.

5.5.8 The return on equity

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

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244 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 54.

determines whether investors will be willing to provide equity to finance the infrastructure.

The various CAPM parameters proposed by GasNet are included in Table 5.3 below. Using the CAPM formula the return on equity proposed by GasNet is 14.19 per cent. In comparison, the parameters proposed by the Commission, as outlined above, result in a post-tax nominal return on equity of 11.15 per cent for this Final Decision. The corresponding real return on equity is 8.80 per cent.

Table 5.3: CAPM parameters

		ACCC Final Decision October 1998	GasNet proposal March 2002	ACCC Draft Decision August 2002	ACCC Final Decision November 2002
real risk free rate	rr_f	3.43	3.20	3.14	3.08
expected inflation	F	2.50	2.50	2.51	2.16
nominal risk free rate	r_f	6.00	5.78	5.72	5.31
debt margin	DM	1.20	1.20	1.38	1.59
real cost of debt	rr_d	4.60		4.49	4.63
nominal cost of debt	r_d	7.22	6.98	7.10	6.90
market risk premium	MRP	6.0	6.0	6.0	6.0
corporate tax rate	T_c	0.36	0.30	0.30	0.30
effective tax rate	T_e	0.27		0.07	0.07
use of imputation credits	γ	0.50	0.50	0.50	0.50
debt funding	D/(D+E)	0.60	0.60	0.60	0.60
debt beta	β_d	0.12	0.06	0.15	0.18
asset beta	β_a	0.55	0.60	0.50	0.50
equity beta	β_e	1.20	1.40	1.0	1.0
nominal return on equity	r_e	13.22	14.19	11.86	11.15
real return on equity	rr_e	10.45		9.13	8.80

Source: ACCC, 1998 Final Decision, p. 62; GasNet access arrangement information, 27 March 2002, pp. 6-7; ACCC analysis.

5.6 Determination of the WACC

5.6.1 Draft Decision

GasNet stated in its initial submission that it has generally selected WACC parameters that are within the range adopted by the Commission in recent decisions. However, it proposed a higher value for beta, cash flow adjustments to reflect asymmetric risks and the use of 10 year bond rates to derive the risk free rate. GasNet stated that it regards its approach as developing an appropriate return that supports the long run benefits of infrastructure development within a framework that has ‘inherent uncertainty’.[245]

Gas Net suggested that the Commission should identify the possible range for the rate of return and then exercise its discretion in selecting a value. Where there is uncertainty the Commission should ‘err on the side of favouring a higher return. GasNet submits that this is required both from an economic and legal perspective’. It regarded this approach as ‘preferable as the welfare benefits of the long run objectives far outweigh the short run benefits of lower prices’.[246]

BHP Billiton accepted that it is important to avoid disincentives to infrastructure investment but does not consider that this should lead to monopoly rents. It suggested that the removal of monopoly rents will allow investment in both upstream and downstream markets to occur. It considered that ‘the need for a high WACC on existing assets to encourage future investment is not a sustainable argument’.[247]

BHP Billiton asserted that the appropriate WACC for GasNet for 2003-2007 is less than 7 per cent as the high prices paid for the Victorian gas assets subsequent to the establishment of the regulatory regime in 1998 indicate that the returns selected by the regulators were too high.[248] The oversubscription of the GasNet float was identified as further support for this view.[249]

The Draft Decision acknowledged that the various CAPM parameters used in regulatory decisions will often be contentious as they impact directly on the return expected by infrastructure owners and operators through their influence on the tariffs paid by users. However, an important aspect of the Commission’s decisions is the selection of specific estimates of the values of the CAPM parameters, and the associated discussion on the parameter values chosen. Using point estimates of inputs allows the CAPM outputs and cash flow analysis carried out by the Commission to also be clearly numerated, consistent and repeatable. The Commission considers that this transparency and repeatability is an important feature of its regulatory approach. In contrast, approaches that generate a wide range of possible outputs can require the exercise of a degree of regulatory judgement which may lead to considerable uncertainty for service providers and other stakeholders. In addition, use of specific values can make it easier to pinpoint contentious aspects which may warrant closer examination.

The Commission noted that it does not propose to adopt the approach of identifying CAPM parameter ranges. However, it has considered carefully the likely costs of under and over estimating a service provider’s cost of capital. For example, it commented in its 1998 Final Decision:

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245 GasNet submission, 27 March 2002, p. 45.

246 ibid., p. 48.

247 BHP Billiton submission, 21 June 2002, pp. 6 and 31. See also Amcor and PaperlinX submission, 24 June 2002, p. 24.

248 BHP Billiton submission, 21 June 2002, p. 32. See also Amcor and PaperlinX submission, 24 June 2002, p. 24.

249 EUAA submission, 11 July 2002, p. 8.

> While the CAPM/WACC framework provides a well recognised theoretical framework to establish the cost of capital, there is less than full agreement on the precise magnitude of the various financial parameters which need to be applied (as evidenced by the range of parameter values suggested by different commentators). ... The Commission has given careful consideration to the value that should be assigned to TPA given the nature of its business and current financial circumstances. Accordingly, the parameter values used are those considered most appropriate. Mostly these fall near the middle of a narrow range based on the information available, however a few, such as the equity beta and the margin on debt, have been chosen to give TPA the benefit of associated uncertainty.[250]

The Draft Decision noted that the Commission considered the suggestion by GasNet that, where there is uncertainty, the Commission should err on the side of favouring a higher return. With respect to the Draft Decision, this was done in a number of ways. For example, the Commission applied a value of gamma of 0.5 rather than 1.0, and selected a higher equity beta value than that suggested by the empirical evidence. Other concessions include not taking into account pre-payments for future tax liabilities already received in calculating the future compensation for benchmark tax liabilities and other elements of costs added to the cash flows not featured in the 1998 Final Decision.

The Draft Decision included a benchmark WACC for GasNet. A cash flow model was used to determine the WACC that will achieve cash flows consistent with the post-tax nominal return on equity calculated through the CAPM.

The Commission found that a pre-tax real WACC of 6.5 per cent was consistent with the post-tax nominal return on equity of 11.9 per cent for GasNet.[251] This compared to the pre-tax real WACC of 8.22 per cent proposed by GasNet.[252] A real vanilla WACC of 6.4 per cent was also consistent with the post-tax nominal return on equity of 11.9 per cent. The Draft Decision noted that consistent with the use of a real vanilla WACC, an extra line was added to the building block approach for the recovery of taxes. However, this would not be required for the next access arrangement period as the modelling suggests that GasNet will not be liable for any taxes in this period.

5.6.2 Response to Draft Decision

In response to the Commission's Draft Decision some interested parties suggested that the WACC included in the decision was too high. BHP Billiton referred to a report from Pareto Associates and argued that it added 'further substantiation for an appropriate WACC to be lower than that calculated by the ACCC in its draft decision'.[253]

In a subsequent submission, BHP Billiton commented that GasNet's commentary regarding regulatory consistency 'is of great concern to all users as there are widely unsubstantiated claims relating to future investments in new infrastructure being curtailed as a recent of low returns and regulatory uncertainty'. It continues: 'if such

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250 ACCC, 1998 Final Decision, p. 63.

251 The nominal vanilla WACC is 9.0 per cent and the implied real tax wedge 0.2 per cent.

252 The nominal vanilla WACC under GasNet's proposal is 9.86 per cent and the implied real tax wedge 1.04 per cent.

253 BHP Billiton submission, 13 September 2002, p. 13.

regulatory consistency was the prime driver behind the GasNet application, then it would have sought a real WACC premium equal to that it currently enjoys'.[254]

The EUAA also referred to work by Pareto Associates, requesting that the Commission explicitly respond to the issues raised. In particular, 'why return on equity and WACC must be higher for Australian utilities than that required for utilities in the UK and US'.[255]

Amcor and PaperlinX also 'believe that the WACC draft decision is still too high, given the relatively risk free nature of the GasNet business' and referred to the Pareto Associates report as support for this view.[256]

The EUCV referred to Pareto Associates and considered that the Commission should verify the return determined via the CAPM with reference to competitive industry returns and other regulatory decisions. It concluded that 'a WACC of about six per cent real would appear to be a reasonable rate of return for the GasNet business'.[257]

The Pareto Associates report that these recent submissions refer to has been provided to the Commission by the Customer Energy Coalition. The report built on its previous work commissioned by BHP Billiton and provided an end user perspective on the proposed revised access arrangements for the Victorian gas industry.[258] It advised that there appears 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 cautious' regulation or regulatory error and suggested that there may be a real risk that the economy's competitiveness will be reduced.[259]

Pareto Associates also noted that the CAPM is a useful tool for regulators to determine returns for utilities. However, it requires the regulator to make a number of judgements relating to the parameters. It suggested that Australian regulators may be unnecessarily conservative in these judgements, particularly in reference to the market risk premium and beta.[260]

In contrast, GasNet did not consider the return proposed in the Commission's Draft Decision to be high enough. It argued that the Commission failed to take into account section 2.24(a) of the Code. In GasNet's view:

> The Epic Energy Case supports the view that seeking to maximise financial returns is a legitimate business interest, provided that the conduct of the relevant service provider does not involve price manipulations or breaches of the TPA.[261]

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[254] BHP Billiton submission, 11 October 2002, p. 22.

[255] EUAA submission, 20 September 2002, p. 6.

[256] Amcor and PaperlinX submission, 13 September 2002, p. 10.

[257] EUCV submission, 13 September 2002, p. 7.

[258] See BHP Billiton submission, 21 June 2002 for the first report which relates to GasNet. The second report was initially provided to the ESC and refers to the Victorian gas distributors.

[259] Pareto Associates, *Victorian gas distribution access arrangement 2003-07*, p. 10 (Customer Energy Coalition submission, 8 October 2002).

[260] ibid., p. 23.

[261] GasNet submission, 20 September 2002, pp. 8-9.

In addition, 'GasNet is also of the view that the Commission has failed to take into account its investment in the GNS'. GasNet stated that one of the assumptions made in 1999 when purchasing the business was that 'the regulatory regime would be applied in a consistent manner over time'.[262] GasNet considered that the Draft Decision violates this assumption and shifts from the pattern established by previous decisions.

GasNet continued, stating that 'the Draft Decision introduces a measure of regulatory inconsistency which is detrimental to GasNet's business interests'. It suggested 'some elements of the decision send a signal to potential investors that regulatory outcomes are unpredictable and cannot be relied upon'.[263]

GasNet stated that the Draft Decision proposes a WACC that 'is the lowest gas or electricity WACC decision made to date'. It did not regard the return as appropriate and expressed concern at the degree of the change from the return in the 1998 Final Decision.[264]

5.6.3 Final Decision

As discussed in the Draft Decision, and noted above in section 5.6.1, the Commission has tended to select CAPM parameters such as beta and market risk premium that give the service provider the benefit of the uncertainty that may exist in relation to those parameters. This course of action ultimately resulted in a real vanilla WACC of 6.4 per cent for the Draft Decision.

Similarly, using a post-tax cash flow model for this Final Decision, the Commission has determined that a real vanilla WACC of 6.30 per cent is consistent with the post-tax nominal return on equity of 11.15 per cent derived from the CAPM in section 5.5 above.

The Commission acknowledges the comments from some interested parties that the proposed return included in its Draft Decision was too high, which is in contrast with GasNet's view. For example, it has carefully considered the views presented by Pareto Associates which suggest that the Commission should be more guided by recent overseas regulatory decisions. While the Commission has taken these decisions into consideration (a summary of US and UK WACC outcomes is included in Table 5.4 below), it is cognisant of the difficulties inherent in adjusting for differences in financial market conditions and institutional arrangements between countries.

The Commission accepts that there will be conflicting views on what the most appropriate return will be for a regulated business. However, these views must be considered in determining the return. In doing so for gas transmission businesses, the Commission must have regard to section 2.24 of the Code.

For example, it could be argued that it would be in the interest of users and prospective users (under section 2.24(f)) for the return, and consequently the tariffs, of a pipeline to be low. However, this may conflict with a need to ensure the safe and reliable

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262 ibid., p. 9.

263 ibid., p. 11.

264 ibid.

operation of the pipeline (section 2.24(c)) and the legitimate business interests of the service provider (section 2.24(a)). It may also conflict with the need to provide a return sufficient for the economically efficient operation of the pipeline (section 2.24(d)).

Conversely, a service provider may argue that a higher return is more appropriate and supports its business interests and investment in the pipeline (section 2.24(a)). A relatively high return may more than provide the cash flow to meet the operational requirements of the pipeline (section 2.24(c)). However, it may not result in an economically efficient operation (section 2.24(d)) nor be in the interest of users (section 2.24(f)) or the public (section 2.24(e)).

It has been in regard to these issues that the Commission has determined that the return it has established for GasNet is, on balance, appropriate. The Commission acknowledges that in assessing some aspects it has placed greater weight on the interests of GasNet pursuant to section 2.24(a) of the Code. This degree of conservatism may have resulted in a return for GasNet that, when compared to decisions made by UK and US regulators, appears to some parties to be high. However, the Commission is mindful that the regulatory regime in Australia is not as developed and accepted as in the UK and US. It is also mindful of the overall public interest in maintaining viable infrastructure businesses to serve numerous sectors of the economy.

In addition, the Commission has had regard to the broader regulatory framework that has been established for GasNet. For example, a benefit sharing mechanism has been established providing an incentive for GasNet to out perform the benchmark costs that are included in the calculation of revenues for the 2003 to 2007 period. A pass through mechanism has also been developed and includes a number of cost categories, providing GasNet with greater certainty as to the treatment of asymmetric costs that may arise. The pass through mechanism reduces the risks faced by GasNet.

As recommended by some interested parties, the Commission has reviewed the return it has calculated from its analysis and model in light of other regulatory decisions and returns achieved by the wider business community. Some benchmark figures are included in the table below.

Table 5.4: Return comparisons

	Date	Return on equity	Vanilla WACC
ACCC: Final decision for TPA	Oct 1998	13.2	6.9
ACCC: Final decision for GasNet	Nov 2002	11.2	6.3
ACCC: Final decision for Powerlink	Nov 2001	11.8	
ACCC: Draft decision for ElectraNet	Sept 2002	11.4	
ESC: Final decision for gas distribution	Oct 2002	11.8	6.8
Ofgem: Independent gas transmission	2002	8.3	5.5
Ofgem: Transco	2001	8.8	5.1
average of UK decisions, 1995-2000			5.6
average of US decisions, 1995-2000			6.6
		5 year average return on equity	10 year average return on equity
All Ords accumulation index	Sept 2002	4.8	11.2

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 (BHP Billiton submission, 21 June 2002); NERA, *International comparison of utilities' regulated post tax rates of return in North America, the UK and Australia*, March 2001.

The Commission is cognisant of the difficulties in comparing its regulatory decisions with the stock market as well as regulatory decisions made in other jurisdictions. Nevertheless, a review of the broader regulatory context and the market provides some perspective on the returns determined by the Commission.

Figures in this table indicate that while the Commission's Final Decision for GasNet provides a benchmark return that is lower than that provided by the 1998 Final Decision, it is not in conflict with the more recent regulatory decisions and is consistent with the fact that rates on Government bonds are now lower than they were in 1998.

In this instance, the Commission concludes that the information collated indicates that the return determined for GasNet in this Final Decision is not inconsistent with the benchmarks and is not unreasonable, particularly in context of the broader regulatory framework established for the business.

On balance, following its analysis detailed earlier and other information regarding returns, the Commission has concluded that the appropriate return is a real vanilla WACC of 6.30 per cent and requires this to be implemented by GasNet for the forthcoming access arrangement period.

Amendment 13

GasNet must adopt the Commission's CAPM parameters as set out in Table 5.3 of this Final Decision to more accurately reflect the current financial market settings. GasNet must use the real vanilla WACC of 6.30 per cent to calculate the return on asset component of revenues for its revised access arrangement.

6. Revenue elements

This chapter considers a number of the components that make up GasNet's benchmark revenue. Elements considered are: operations and maintenance expenditure; capital raising costs, the K factor adjustment; the efficiency carryover; allowances for asymmetric risks; working capital, capital expenditure; depreciation; inflation; and pass through amounts.

6.1 Operations and maintenance expenditure

6.1.1 Code requirements

The Code (sections 8.36 and 8.37) allows for recovery of the operating, maintenance and other non-capital costs that a prudent service provider, acting efficiently and in accordance with good industry practice, would incur in providing the reference service. 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. The Code also requires consideration of section 2.46 and section 2.24 criteria whenever such as assessment is made.

Attachment A to the Code requires the service provider to publicly disclose certain costs in the access arrangement information, unless it would be unduly harmful to the legitimate business interests of the service provider, or a user or a prospective user. The costs to be disclosed include wages and salaries, contract services including rental equipment, materials and supply, and corporate overheads and marketing. The service provider must also disclose gas used in operations. Some disaggregation by zones, services or categories is also required.

6.1.2 Current access arrangement provisions

Forecast operations and maintenance expenditure for the initial access arrangement period is detailed in the access arrangement information for the PTS and WTS. Table 6.1 below shows annual operations and maintenance cost forecasts for this period disaggregated into various components.

Table 6.1 also presents actual costs achieved by GasNet in the first access arrangement period. As indicated by the table, GasNet's operations and maintenance expenditure was substantially lower than that which was forecast, particularly for 1999 to 2001. GasNet expressed concern that interested parties might misconstrue these data which it considers reflect unsustainable savings. This issue is discussed below and also under access arrangement information in section 9.5 of this Final Decision in reference to access arrangement information.

Table 6.1: Benchmark and actual operations and maintenance costs, 1998 to 2002

	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Labour	6.33	6.48	6.53	6.58	6.75
Total materials	1.04	1.05	1.06	1.06	1.09
Total outside services	6.39	6.20	5.79	5.24	4.91
Occupancy	0.85	0.86	0.86	0.87	0.89
Communications	0.17	0.18	0.18	0.18	0.18
Total motor vehicles	0.70	0.70	0.70	0.71	0.73
PC, furniture, office equipment	0.59	0.55	0.51	0.53	0.56
Training and conferences	0.27	0.28	0.28	0.29	0.29
Travel and accommodation	0.26	0.26	0.27	0.27	0.28
Miscellaneous taxes	0.88	0.87	0.88	0.89	0.91
Sundry	0.62	0.62	0.63	0.64	0.66
Fuel gas	1.10	1.14	1.23	1.25	1.30
Murray Valley	0.08	0.20	0.20	0.21	0.21
Total Benchmark[a]	19.29	19.38	19.11	18.70	18.75
Actuals achieved	16.97	14.14	11.86	13.90	18.55[b]

Source: TPA access arrangement information, 30 November 1998, p. 8; GasNet response to Commission, 9 May 2002.

Notes: (a) This total incorporates annual regulatory costs that were forecast but not paid by GasNet. The data only relate to the PTS and WTS. They do not include forecast costs associated with the Interconnect Pipeline, Springhurst compressor, Iona compressor and the Southwest Pipeline.

(b) Estimated actual expenditure during 2002.

6.1.3 GasNet proposal

In its proposed access arrangement information, GasNet estimated that costs will increase from $18.4 million in 2003 to $22.0 million in 2007 in nominal terms. Forecasts for every year except 2003 are higher than the estimated actual in 2002 of $18.55 million. A breakdown of forecast costs is presented in Table 6.2.

Table 6.2: Forecast operations and maintenance expenditure, 2003 to 2007

	$ million[a]				
	2003	**2004**	**2005**	**2006**	**2007**
Pipeline maintenance	5.9	6.8	6.2	7.4	7.4
Compressor maintenance	3.3	3.6	3.7	3.7	3.8
General and administrative	8.0	8.4	8.6	8.9	9.1
Fuel gas	1.2	1.3	1.4	1.6	1.7
Total	18.4	20.1	19.9	21.6	22.0

Source: GasNet submission, 27 March 2002, pp. 83-84.
Note: (a) Nominal dollars.

GasNet provided a number of reasons for the forecast increases in costs. These included: an increase in pigging operations on a number of the older pipelines in the system over 2003 to 2007; an allowance for ongoing litigation expenses arising from the Longford incident; an extraordinary increase in insurance costs; the need to bolster the company's skill base and recruit junior staff; and an allowance for the expansion of general marketing activities.[265]

6.1.4 Submissions to Issues Paper

Amcor and PaperlinX commented in their submission that GasNet has provided limited comparative data in relation to its proposed operations and maintenance expenditure. They contended that a number of different benchmark divisors should be assessed rather than single variables, and that the aggregate of GasNet and VENCorp costs should be used when undertaking benchmarking. Further, they commented that any operations and maintenance costs should be related to the benefit the consumer receives. In this regard, Amcor and PaperlinX were particularly concerned with an allowance for marketing of gas, arguing that GasNet does not substantiate this claim and does not reference expected outcomes from this marketing activity. Amcor and PaperlinX proposed that GasNet should provide further information to substantiate its claims.[266]

BHP Billiton stated that GasNet includes an allowance for marketing costs, but does not include what outcomes are expected from this marketing activity.[267] BHP Billiton expressed concern with the extent of information provided by GasNet. BHP Billiton stated that GasNet does not include the amounts forecast for the first access arrangement period or the actual expenditure incurred. It also stated that operations and maintenance cost forecasts for 2003-2007 do not appear to recognise any savings made in the first access arrangement period.[268]

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265 GasNet submission, 27 March 2002, pp. 83, 85 and 89.

266 Amcor and PaperlinX submission, 24 June 2002, pp. 21-22.

267 BHP Billiton submission, 17 May 2002, pp. 12-13.

268 BHP Billiton submission, 21 June 2002, p. 43.

TXU expressed concern with the lack of historical operations and maintenance expenditure information and suggested that a statement of historical operating costs and capital expenditure be provided as a baseline.[269]

EnergyAdvice expressed concern relating to the appointment of a business development manager to promote gas use. EnergyAdvice stated that:

> Given the magnitude of the initial tariff increases which are effectively locked in over the next five years, GasNet may have a difficult job attracting new or incremental loads. This is particularly true of customers who will have experienced significant price shock as a result of this Access Undertaking being implemented in its present form and were contemplating further use of gas for plant expansion or new projects.[270]

EnergyAdvice also commented on the inclusion of ongoing litigation expenses for the Longford incident in 1998. It suggested that if GasNet is successful in its legal action, the cost base should be reduced accordingly, and that if GasNet receives a judgement against it, then it should bear the resultant cost.[271]

6.1.5 Draft Decision

For the Draft Decision, the Commission undertook a detailed assessment of particular operations and maintenance cost claims made by GasNet, as well as an analysis of general cost categories. The Commission's analysis in the Draft Decision in relation to GasNet's forecasts is reported below.

Marketing costs

The forecasts proposed by GasNet included an annual allowance of $400 000 to promote growth in gas volumes. This represents an increase from $120 000 in 2002 allowed in the current access arrangement provisions. GasNet commented in its access arrangement submission that marketing costs are required as it faces substantial volume risk. GasNet also contended that it must provide a supportive role in the marketing of gas, particularly to large-use applications such as cogeneration and power-station developments.[272]

As noted, Amcor and PaperlinX expressed concern with the allowance for gas marketing on the basis that GasNet does not substantiate the claim and does not reference expected outcomes from this marketing activity. EnergyAdvice also commented on the inclusion of these costs. While the Commission acknowledged the concerns raised, it considered that the proposed allowance for marketing costs was not unreasonable. Further information from GasNet clarified that the objective of the marketing allowance is to encourage gas usage in Victoria through liaison with potential large users such as power station, cogeneration and large gas-using industrial projects.[273] The Commission considered that such marketing activities correspond with generic market development activities allowed for under section 8.36 of the Code and proposed to accept the forecast cost in the determination of revenues and tariffs. It was

[269] TXU submission, 31 May 2002, p. 32.

[270] EnergyAdvice submission, 30 May 2002, p. 9.

[271] EnergyAdvice submission, 30 May 2002, p. 10.

[272] GasNet submission, 27 March 2002, p. 89.

[273] GasNet response to submissions, 12 June 2002, p. 23.

noted that the Commission will review GasNet's actual marketing expenditure during the second access arrangement period at the next scheduled review of the access arrangement.

Exceptional costs

GasNet provided a breakdown and a discussion of exceptional costs claimed for the second period.[274] The Commission was concerned that a number of the exceptional costs noted by GasNet generally relate to both regulated and unregulated GasNet operations (specifically, listing and governance costs, increases in insurance costs), and therefore overestimate the amount which is relevant for determining the reference tariffs. The Commission therefore required that GasNet correct these figures to allow an assessment to be carried out prior to the Final Decision.

Ongoing litigation expenses

GasNet proposed an allowance for ongoing litigation expenses arising from the Longford incident in 1998 of $200 000 annually in 2003-2007 (nominal terms).[275] The Commission considered that this allowance is not appropriate given that the Longford incident occurred prior to the commencement of the first access arrangement period, and GasNet was compensated for such risks through the beta parameter in the first access arrangement period. Furthermore, it was argued that it is unreasonable to expect users to fund GasNet's litigation given that GasNet has not proposed to share any compensation received with users should it be successful in court.

Licence fees

In its revised access arrangement information, GasNet forecast an amount for pipeline licensing fees. These fees and levies made up a substantial part of the $1.3 million regulatory/utility charges claimed by GasNet.[276]

The Commission acknowledged that GasNet is required to pay licence fees and charges to a number of government authorities. GasNet provided data to the Commission disaggregating the total payable into specific licence fees and levy components. The Commission assessed these components and stated that it considers that they are not unreasonable.

Regulatory review costs

In Table 8-3 of GasNet's submission summarising exceptional costs, GasNet proposed an allowance for review costs of $0.5 million in 2002, $1.0 million in 2006 and $0.6 million in 2007. This allowance was proposed to cover the costs associated with the access arrangement revision process in those years. The Commission understood that GasNet intended to recover regulatory review costs incurred in 2001 and 2002 in 2003 tariffs, and that these costs had not been included in operations and maintenance cost forecasts presented in Tables 3-6 and 3-7 of its proposed access arrangement information as they had not been finalised.

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[274] GasNet submission, 27 March 2002, p. 90.

[275] ibid.

[276] GasNet access arrangement information, 27 March 2002, p. 9.

In addition, GasNet has not included forecast review costs for 2006 and 2007 in its proposed access arrangement information. The Commission understood that GasNet proposes to recover these costs in the third, rather than the second period, as these costs relate to revisions to the access arrangement for the third period.

In the Draft Decision, the Commission considered that it is reasonable to include prudent regulatory review costs incurred in 2001 and 2002 in the reference tariffs for 2003. As noted, GasNet has estimated review costs in 2002 of $0.5 million. In addition to this amount, GasNet incurred an undisclosed amount in 2001 associated with the preparation of the revisions to the access arrangement. The Commission noted that it was likely that the total figure that would be claimed by GasNet would be in excess of $0.5 million. The Commission proposed that GasNet publicly provide a detailed itemised breakdown of these costs as part of the current assessment process so that the Commission and interested parties can assess whether the costs incurred are prudent.

The Commission considered that it is appropriate to not include forecasts for review costs in 2006 and 2007 in the reference tariff calculation for the second access arrangement period. The Commission acknowledged that this approach to the treatment of operations and maintenance expenditure represents a departure from incentive regulation, but as noted in relation to the proposed pass through mechanism (section 3.2.3 of the Draft Decision and of this Final Decision), this approach is acceptable under the provisions of the Code.

Insurance costs

GasNet proposed an increase in insurance costs from an amount of $0.3 million per year in the first access arrangement period to $1.7 million per year.[277] The Commission understood that this figure represents one of the exceptional costs incorrectly calculated (as noted above), and is therefore slightly higher than the figure which should be used to calculate reference tariffs.

The Commission was concerned with the large increase in insurance costs and requested GasNet to substantiate its claim. In response, GasNet provided the Commission with invoices relating to the various insurance policies held by GasNet. The Commission assessed this information and found all costs to be legitimate. As a result, the Commission proposed to accept these costs when amended according to the proposed amendment in the Draft Decision.

Pigging schedule

In its access arrangement submission GasNet noted its intention to undertake substantial pigging activities in the 2003-2007 period.[278] The Commission requested further clarification on this issue, and GasNet agreed to release a list of current and planned pigging operations for 2001-2007. This information is presented in Table 6.3 below.

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[277] GasNet submission, 27 March 2002, p. 90.

[278] ibid., p. 85.

Table 6.3: Current and planned pigging operations, 2001-2007

Line name	Recorded length (km)
Brooklyn to Ballan	66.6
Euroa to Shepparton	34.5
Shepparton to Tatura	16.2
Tatura to Kyabram	21.3
Ballan to Ballarat	22.7
Ballan to Bendigo	90.8
Derrimut to Sunbury	24.0
Guildford to Maryborough	31.4
Mt Franklin to Kyneton	24.5
Mt Franklin to Bendigo	50.8
Wandong to Kyneton	59.5
Dandenong to West Melbourne	36.18
South Melbourne to Brooklyn	12.8
Tyers to Morwell	15.7
Pakenham to Wollert	93.1
Morwell to Dandenong	126.8
Longford to Dandenong	174.2
Keon Park to Wollert	14.1
Rosedale to Tyers	34.3
Longford to Rosedale	30.5
Bunyip to Pakenham	18.7

Source: GasNet response to Commission, 2 August 2002.

It was noted that this information would be used in the assessment of operations and maintenance expenditure achieved in the second period during the next revisions process.

The costs associated with this pigging program were assessed by the Commission and found to be not unreasonable. Consequently, the relevant expenditure has been included in the determination of revenues and tariffs for 2003 to 2007. The Commission noted that, although GasNet adopts a fifteen year pigging cycle, no associated expenses were reported for 1998, 1999 and 2000. To the extent that pigging operations have been deferred, additional costs would be expected in the second access arrangement period.

Executive remuneration

The Tariff Order specifies a number of fixed principles to be used by the Commission for the second access arrangement period. Clause 9.2(a)(6)(C) requires the Commission to have regard to:

> The level of executive remuneration in TPA by reference to any relevant interstate and international private sector benchmarks for that remuneration.

This information was not provided to the Commission in the initial information provided by GasNet dated 27 March 2002. Accordingly, the Commission requested information from GasNet on executive pay, which was provided on a confidential basis. This information was assessed against Australian and overseas benchmarks, and the Commission concluded in the Draft Decision that the amounts reported by GasNet are reasonable.

Assessment of broad cost categories

The Commission also undertook an assessment of forecasts for the following general operations and maintenance cost categories: pipeline maintenance, compressor maintenance, general and administrative costs and fuel gas costs. The Commission's assessment of normalised pipeline maintenance, compressor maintenance and general and administrative costs net of exceptional costs suggested that the forecasts proposed by GasNet are not unreasonable. The Commission requested, and was provided, further information substantiating GasNet's forecast fuel gas costs.[279] Assessment of this information also suggests that the forecasts proposed by GasNet are not unreasonable.

Further, GasNet provided the Commission with KPIs relating to the forecast operations and maintenance costs in 2003 (net of working capital and compressor fuel costs), and a detailed benchmarking report compiled by Cap Gemini as an annexure to its submission. The Commission assessed the benchmarks provided by GasNet, and this discussion was presented in section 10.2 of the Draft Decision (and of this Final Decision).

Increase in operations and maintenance expenditures

As noted, GasNet achieved operations and maintenance costs that are significantly below those forecast. For example, in 2001 a total of $18.70 million was provided for in reference tariffs, but GasNet's total expenditure was only $13.90 million. Further, GasNet proposed forecast operations and maintenance costs per year in the range of $18.4 to $22 million (nominal) for the subsequent access arrangement period.

GasNet considered that the decline in actual operations and maintenance costs in the first access arrangement period was not sustainable. GasNet stated that it managed 'to temporarily reduce some costs in response to large revenue losses resulting from warm weather and lost gas sales' during that period.[280] GasNet added that the reduction in costs was achieved through delays in filling vacant positions, lower levels of business marketing and reduced levels of administrative support.[281] In addition, as noted above, no pigging expenses were reported for 1998, 1999 and 2000. The Commission commented that as any deferred pigging operations would need to be undertaken in later years, associated costs savings would not be sustainable.

GasNet also substantiated the proposed forecast increase in costs in the second access arrangement period. Apart from the temporary gains made in the first period, the large 'step' increase in costs between 2001 and 2003 was primarily the outcome of:

- the extraordinary increase in insurance costs;
- the proposed increase in pigging operations in 2003-2007;

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[279] GasNet response to Commission, 11 July 2002.

[280] GasNet response to submissions, 24 July 2002, pp. 16-17.

[281] GasNet submission, 27 March 2002, p. 89.

- additional ongoing costs related to the public listing of GasNet on the Australian stock exchange;
- the proposed increase in marketing costs; and
- the increase in staffing levels and training of junior staff to a level that is sustainable for the operation of GasNet.[282]

As noted, the Commission undertook a detailed assessment of the costs forecast by GasNet in the second period and proposed several amendments. The Commission considered that the remaining increase in operations and maintenance costs proposed by GasNet between 2001 and 2003 is not unreasonable.

6.1.6 Response to Draft Decision

GasNet, in its submission of 20 September 2002, stated that it is required to install at least three additional gas chromatographs on its system under the MSOR. GasNet argued that, due to this investment, it will incur additional ongoing operations and maintenance costs of approximately $70 000 per year, but that this forecast will be amended once costings are completed.[283] On 24 October GasNet provided the Commission with what it considers to be a more accurate estimate of these costs, totalling $45 244 per year.[284] It was proposed that the amount should be added to each year's forecast operations and maintenance costs, except in 2003 when these costs would be pro-rated for half the year.[285]

GasNet also raised the issue of ongoing litigation expenses. It considered that the Commission's proposal to disallow these costs reflects a misunderstanding of GasNet's involvement in the Longford litigation. GasNet stated that it is defending an action brought by other parties, and therefore the Commission's assertion that it is unreasonable for users to fund this expense is unfounded. In addition, it is asserted that the action against GasNet was brought after the access arrangement period had begun and was therefore not considered when determining the rate of return applicable for the first access arrangement period.[286]

In response to the proposed amendment in the Draft Decision, GasNet publicly provided a revised table of exceptional costs which reflects only those costs applicable to its regulated operations.[287] This table includes new estimates of insurance premiums which are higher than those costs identified in the original submission.[288] On 24 October 2002 GasNet provided the Commission with insurance policy invoices in support of its claim, the details of which are discussed below.[289]

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282 ibid., pp. 83, 85, 89-90.

283 GasNet submission, 20 September 2002, pp. 23-24.

284 GasNet response to Commission, 24 October 2002.

285 GasNet submission, 20 September 2002, p. 24.

286 ibid., p. 25.

287 GasNet letter to Commission, 13 September 2002, Attachment A.

288 GasNet submission, 20 September 2002, p. 24.

289 GasNet response to Commission, 24 October 2002.

In the Draft Decision, the Commission requested an itemised breakdown of regulatory review costs. A public version of these costs was provided by GasNet on 30 October 2002, with an attached confidential breakdown of consultancy activities.[290] An outline and discussion of these costs is presented in the following section of this Final Decision.

In its submission to the Draft Decision, the EUCV stated that past operations and maintenance expenditure represents the starting point for an assessment of reasonable future operations and maintenance costs. It noted that GasNet saved an average of $4 million per annum in the first period, but that GasNet identifies certain savings as being unsustainable. The EUCV claimed that GasNet specifies that the savings were the result of the deferral of pigging, staff replacements, and other reasons such as warmer weather reducing demand and less business marketing. According to the EUCV, GasNet asserts that 'the new opex of nearly one third is due to the existence of increases in staffing and pigging'.[291]

The EUCV stated that the 'ACCC has queried some of the opex increases sought but appears to accept the basic level of opex requested by GasNet'. It argued that Commission provided no quantification for the increase in costs, and that this runs counter to a requirement that the regulator explain any exercise of regulatory judgement as outlined in the Epic decision. It is stated that the Commission asked for an itemised breakdown of costs in the Draft Decision but that this has not been provided.

The EUCV raised a number of concerns with GasNet's claims and the Commission's decision. One issue raised relates to whether the apparent carry forward of a significant amount of pigging work was deferred from the first access arrangement period to the second access arrangement period. The EUCV asserted that deferral of pigging amounts to GasNet being paid twice for carrying out the same work, and that the Commission appears to condone this double payment.[292]

Another issue raised by the EUCV relates to the validity of the claim that the increase in operations and maintenance expenditure is in part the result of the deferral of staff appointments and the increase in employment of junior staff. EUCV asserted that based on its experience with staff costs, GasNet would appear to have highly paid staff or major staff shortages. EUCV stated that 'if GasNet could 'survive' at this operations and maintenance cost level without any reduction of its operating performance for four years, then this is tantamount to an identification of good benchmark performance, and there is no justification for the replacement of the staff so obviously needed'.[293]

EUCV also responded to the argument presented by GasNet that reduced operations and maintenance costs in the first period was the result of the reduction in sales due to warmer weather. As consumers of gas, the EUCV argued that there is no apparent basis on which reduced sales could impact on costs, other than perhaps less fuel gas requirements. It is also argued that 'at best the saving from marketing could only be in

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290 GasNet response to Commission, 30 October 2002.

291 EUCV submission, 9 October 2002, p. 5.

292 ibid., pp. 4-5.

293 ibid., p. 5.

the order of $100 000 per year'.[294] EUCV also claimed that it was 'not able to identify savings valued at anything like $4 million per annum unless they are a carry forward of previously approved and paid for activities such as pigging'.[295]

The EUAA raised concerns regarding the allowance for gas marketing claimed by GasNet and accepted by the Commission. It argued that GasNet does not provide evidence of the need of this activity and does not indicate what outcomes (or benefits) are expected.[296]

In their second submission to the Draft Decision, Amcor and PaperlinX assert that GasNet's operations and maintenance cost claims are significant and that these claims have been attributed to uncosted increases in staffing, pigging and other items. It is argued that no reasonable information pertaining to past operations and maintenance expenditure has been made public which would allow users to confirm that the cost claims for the next period are fair, reasonable and efficient.[297] It is stated that the ACCC must reject GasNet's ambit claims and must apply an appropriate efficiency saving factor, consistent with the savings clearly achieved in the first access arrangement period'.[298]

Amcor and PaperlinX also note concern that some operations and maintenance expenditure savings may have been achieved in the first period through the deferral of costs. It is asserted 'that these costs are being claimed again in the next period, effectively resulting in a double dipping of operations and maintenance costs.[299]

BHP Billiton addressed the related issues of benefit sharing and operations and maintenance costs in its second submission to the Draft Decision. As with the EUCV, BHP Billiton stated that past operations and maintenance expenditure should be taken as the starting point for any assessment of efficient expenditure claims.[300] BHP Billiton stated that it is concerned with the Commission's acceptance of GasNet's claim that the reduced operations and maintenance expenditure in the first period that averages about $4 million per annum is unsustainable, and argued that this should not be accepted without rigorous external benchmarking.[301] BHP Billiton added that the ACCC advised that GasNet was to provide a detailed breakdown of operations and maintenance costs from the first period, but that the recent additional information provided by GasNet does not enable verification of its claims. It stated that without verification the Commission must reject GasNet's claims that operations and maintenance expenditure savings cannot be sustained into the second access arrangement period.[302] Concern was

294 ibid.

295 ibid., p. 6.

296 EUAA submission, 20 September 2002, p. 3.

297 Amcor and PaperlinX submission, 10 October 2002, p. 1.

298 ibid., p. 2.

299 ibid., p. 2.

300 BHP Billiton submission, 11 October 2002, p. 7.

301 ibid., p. 6.

302 ibid., p. 6.

also raised with the validity of the KPI benchmarks provided by GasNet (see section 10.2).[303]

BHP Billiton raised a number of specific issues of concern, many of which overlap with the concerns voiced by the EUCV. First, BHP Billiton was apprehensive that the Commission's Draft Decision proposed to accept GasNet's claim that it made temporary cost savings due to revenue losses resulting from warmer weather. It argued that the K factor mechanism provides some compensation for reduced gas sales. It states that while GasNet has claimed nearly $14 million as a K factor adjustment, it offers no relief to users for the reduced operations and maintenance expenditure achieved from this gas demand reduction.[304] BHP Billiton is of the view that:

> With GasNet's relatively fixed overhead structure, its ability to reduce its opex as a result of reduced gas sales is relatively modest, and it is because of this, that GasNet has the ability to recover some of the lost revenue through the K factor adjustment.[305]

Second, BHP Billiton was concerned with the argument that savings in operations and maintenance costs were made by deferring the appointment of a Chief Financial Officer and other staff. It asserted that a costing of staff noted as absent would account for only a few hundred thousand dollars per year of the fall in operations and maintenance expenditure. Thus, it argued, the below budget operations and maintenance costs in the first four years of the initial access arrangement period is not supported by the statement from GasNet that it faced inadequate staffing levels during those years.[306]

Third, BHP Billiton argued that GasNet is effectively claiming payment twice for some tasks, and that this double dipping of operations and maintenance costs supports a large increase in GasNet's expenditure. According to BHP Billiton, GasNet advised that certain savings were achieved by the deferral of costs, such as pigging costs, and revenues have already been provided for these costs in the first access arrangement period. It is asserted that the Commission must require GasNet to demonstrate the extent of the operations and maintenance expenditure deferred by GasNet before it approves costs for the second access arrangement period.[307]

In conclusion on this issue, BHP Billiton argued that GasNet did not achieve unsustainable savings in its current operations and maintenance costs. It argued that 'there is clear evidence that GasNet has overstated its future opex needs and the ACCC needs to address this'.[308]

GasNet responded to a number of the issues raised by the second BHP Billiton submission to the Draft Decision. With regard to the 'double dipping' of operating costs, GasNet argued that it has never made a statement that certain operations expenses, including pigging, had been deferred during the current access arrangement period. GasNet stated that the decision to conduct pigging is based on a range of

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303 ibid., p. 9.

304 ibid., pp. 7-8.

305 ibid., p. 8.

306 ibid.

307 ibid., pp. 6-7.

308 ibid., p. 9.

factors, and that it was determined to not be necessary to pig in 1998-2000 but necessary in 2001 and 2002. GasNet stated that there was no specific budget for pigging in the original tariff forecast.[309]

6.1.7 Final Decision

In response to submissions to the Draft Decision, the Commission has undertaken further detailed analysis of GasNet's forecast operations and maintenance costs. The first part of this assessment discusses future operations and maintenance cost claims, the second part assesses the concern with the increase in costs between the first and second period, while the third part concludes.

Future operations and maintenance costs

Ongoing litigation costs

GasNet stated in its submission in response to the Draft Decision that the Commission's proposal to not accept ongoing litigation expenses reflects a misunderstanding of GasNet's involvement in the Longford litigation, and that the action against GasNet was brought after the access arrangement period had begun and was therefore not a relevant factor in the determination of the rate of return applicable to the first period.[310]

The Commission acknowledges that it was not aware of the details of the Longford litigation at the time of writing the Draft Decision. The Commission understands that the action was brought by gas consumers against Esso, who initiated a cross-claim in negligence against GasNet and other service providers on 9 August 1999.

Nonetheless, the Commission does not consider this allowance for litigation costs to be a prudent expense. Litigation expenses associated with the Longford explosion are the outcome of specific contractual relationships arranged by GasNet's predecessor. A benchmark service provider acting prudently (section 8.37 of the Code) would not incur such specific risks and consequential costs. Moreover, GasNet joined the action in August 1999 which was prior to the public float of GasNet's assets in 2001. The risks associated with the Longford litigation were actually flagged in the initial public offering prospectus, where it was stated that 'GasNet may have a liability which at the date of this Prospectus is not able to be quantified but which may be material'.[311] Thus, these risks would have been incorporated in investor's decisions and the market price for GasNet's units. It would constitute a double counting of costs if users were required to fund this presently unknown potential cost. Accordingly, the Commission considers that the inclusion of such an allowance would not be in the interests of users and prospective users nor in the public interest (section 2.24(e) and (f)). For the same reasons, these costs should also not be incorporated in the pass through mechanism.

[309] GasNet response to BHP Billiton submission, 18 October 2002, p. 1.

[310] GasNet submission, 20 September 2002, p. 25.

[311] GasNet Australia Trust Prospectus, 22 October 2001, pp. 62-63.

Amendment 14

GasNet must amend clause 3.5 of its revised access arrangement information to exclude litigation costs from operations and maintenance cost forecasts. In addition, litigation costs must not be incorporated in the pass through mechanism.

Marketing costs

The EUAA raised concerns in its submission to the Draft Decision with the allowance for gas marketing claimed by GasNet. It argued that GasNet does not provide evidence on the need for this activity and does not indicate what outcomes are expected from this activity.[312]

After further consideration, the Commission reiterates that its acceptance of an allowance for gas marketing is appropriate. This marketing allowance does not relate to general promotional activities, but involves the encouragement of gas usage amongst potential large end-users such as power stations, cogeneration and large gas-using industrial projects.[313] While the expected outcomes of this activity have not been quantified, GasNet states that it faces a substantial financial incentive in retaining existing large customers and encouraging new users of the system. The Commission notes that marketing activities are permitted under section 8.36 of the Code and should promote the legitimate business interests and investment in the pipeline (section 2.24(a)). To the extent that volume growth may generate lower tariffs in the long run, this marketing activity is consistent with the long run interests of users and prospective users and the public interest (section 2.24(e) and (f))

Inflation forecasts

The Commission understands that GasNet's operations and maintenance cost modelling includes an inflation forecast of 2.5 per cent per year for the period 2002-2007. However, as noted in section 5.5.1, the Commission has calculated a market-based forecast inflation figure of 2.16 per cent per year for the forthcoming access arrangement period. The Commission has decided that this new estimate should be adopted by GasNet in the calculation of all operations and maintenance cost forecasts in the second access arrangement period. The Commission considers that this escalation figure should be used for all of GasNet's operations and maintenance costs, for example labour costs, where an increase in wages and salaries above inflation might occur but would be expected to represent a reward for productivity gains made by the workforce.

Amendment 15

GasNet must amend clause 3.5 of its revised access arrangement information so that an inflation estimate of 2.16 per cent is used when calculating all operations and maintenance cost forecasts in the second access arrangement period.

312 EUAA submission, 20 September 2002, p. 3.

313 GasNet response to submissions, 12 June 2002, p. 23.

Gas chromatographs

As noted earlier, GasNet stated in its submission to the Draft Decision that it is required under the MSOR to install and operate at least three additional gas chromatographs. At the time GasNet estimated that the ongoing costs associated with the operation of this equipment would be in the order of $70 000 per year, but provided an updated estimate of these operating costs on 24 October 2002.[314] The disaggregation of these costs is summarised in the following table.

Table 6.4: Forecast gas chromatograph costs

Cost	$ million
Cylinder gas (bottled inert test gas)	14 220
Materials and spares	12 000
Travel	1 600
Labour	17 424
Total	45 244

Source: GasNet response to Commission, 25 October 2002.

The Commission's technical consultant was concerned that the initial forecast of $70 000 would not be consistent with prudent expenditure, but has assessed the new estimate of $45 244 per year and considers that it is not unreasonable. As advised by GasNet, this amount will be pro-rated for half a year in 2003, and an allowance for the full amount provided for each subsequent year in the access arrangement period.

Amendment 16

GasNet must amend clause 3.5 of its revised access arrangement information to include an allowance of $22 622 in 2003 and $45 244 in 2004-2007 (2003 dollar terms) in operations and maintenance cost forecasts associated with additional gas chromatographs.

Regulated versus unregulated proportions

General and administrative (or overhead) costs incurred by GasNet relate to both the regulated and unregulated assets of the company. In a public response to a question from the Commission, GasNet stated that it allocated 90.27 per cent of exceptional costs (and other overhead costs) to regulated assets, and the remainder to unregulated assets.[315] The details of this allocation method are set out in a confidential model provided to the Commission.

The Commission has assessed the model provided by GasNet and notes that GasNet has excluded two compressors from its calculation of unregulated assets, the Bulla Park and Young compressors, which are located in New South Wales. The reason according to GasNet for the exclusion of these assets is that they were constructed in response to the Longford explosion but are currently not in use.

[314] GasNet response to Commission, 25 October, 2002.

[315] GasNet response to Commission, 13 September 2002.

The Commission considers that these compressors should be included in the unregulated assets and thus in the calculation of the proportion of overhead costs allocated to the regulated component of the system. Even though these compressors are currently not in use, company overhead resources, such as insurance and managerial staff, are utilised in the maintenance of these assets. It would be inconsistent to exclude these assets from the calculation but incorporate other unregulated capital that uses similar company resources.

When the Bulla Park and Young compressors are incorporated in the calculation, regulated assets constitute 88.23 per cent of total assets held by GasNet. Consequently, the Commission considers that only 88.23 per cent of company overheads should be recovered through regulated operations and maintenance cost forecasts. Accordingly, the following amendment is required to the access arrangement information.

Amendment 17

GasNet must amend clause 3.5 of its revised access arrangement information so that operations and maintenance cost benchmarks for the second access arrangement period only include 88.23 per cent of total general and administrative cost forecasts.

Insurance costs

In its initial submission, GasNet proposed an increase in insurance costs from $0.3 million per year allowed in the 2002 benchmarks to $1.7 million in 2003.[316] It was later recognised by GasNet that these figures related to both the regulated and unregulated assets of the company and therefore overestimated the portion that can be recovered in regulated revenues. In September 2002, GasNet provided a new estimate of 2003 insurance costs of approximately $2 million (which is an increase of $1.77 million over the 2002 benchmarks).[317] Unlike the original amount proposed by GasNet, these estimates relate only to the regulated portion of GasNet's assets.

The Commission was concerned with the increase in insurance costs from that initially proposed and requested that GasNet submit new information to substantiate its claim. In response to this request GasNet provided the Commission with its insurance policy invoices on 24 October 2002. The Commission has assessed the invoices provided by GasNet and has decided to use the amounts denoted as the basis of the insurance allowance in 2003. This differs from the approach adopted by GasNet, which was based on estimates of costs likely to be incurred in 2003, not actuals in 2002. The Commission, however, has decided to make a number of adjustments to the amounts specified on the policy invoices.

First, one of the premiums taken out by GasNet is for directors and officers liability relating to the initial public offering. The Commission has decided to omit these costs from the calculation. This is because it considers that the cost of this insurance premium is covered under benchmark equity raising costs, and that the inclusion of this amount would constitute a double counting of costs.

[316] GasNet access arrangement submission, 27 March 2002, p. 90.

[317] GasNet response to Commission, 13 September 2002.

Second, the Commission has not included any GST costs in the insurance allowance. This is because GasNet receives a rebate for the majority of GST expenses incurred.

Third, given that these premiums cover both regulated and unregulated assets, the Commission has adjusted the amounts so that only the portion of these costs associated with regulation (88.23 per cent) should be included in forecasts. Even though some policies only cover regulated pipeline assets, the Commission considers that only a portion of these costs should be allocated, consistent with the general approach. Fourth, the Commission considers that the premiums should be escalated by inflation into 2003 dollar terms.

Adopting this methodology, the Commission calculates that a total allowance for insurance of $1 730 634 should be incorporated in 2003 benchmark revenue calculations. This figure will be used as the benchmark for any insurance policy pass through event that may be proposed in 2003. This figure escalated additionally by 2.16 per cent per year generates the benchmarks relevant for the subsequent years for the insurance pass through.

Amendment 18

GasNet must amend clause 3.5 of its revised access arrangement information to only incorporate a total of $1 730 634 (in 2003 dollars) per year for insurance in 2003 operations and maintenance cost forecasts.

Regulatory review costs

As noted earlier, the Commission requested in the Draft Decision a detailed itemised breakdown of regulatory review costs from GasNet so that the Commission and interested parties could assess whether these costs are prudent. In response to this request, GasNet provided the Commission on 30 October with a broad disaggregation of these costs and a confidential breakdown of the consultancies undertaken. Table 6.5 below presents the costs publicly provided by GasNet.

Table 6.5: Regulatory review costs

Cost	$ million	
	2001	**2002**
Consultants	372 208	22 026
Contractors	109 548	97 663
Legal expenses	258 302	249 159
Miscellaneous expenses	5 076	3 431
Total	745 134	372 279

Source: GasNet response to the Commission, 30 October 2002.

GasNet argued that details of the specific consultancies should remain confidential as the charges are based on negotiated outcomes and therefore publication may be commercially detrimental to the individual consulting firms.[318] With regard to the contractor expenses, GasNet asserted that these costs cover two contractors who assisted in the development of regulatory accounts, detailed forecast volumes and the tariff model. In addition, GasNet stated that legal expenses cannot be disaggregated as they were incurred under a combination of fixed price contract and hourly rates, but that they only relate to regulatory review activities undertaken by the company. GasNet has not provided an estimate of the in-house costs relating to the review.[319]

The Commission has assessed the regulatory review cost information provided by GasNet, and is of the view that the legal and contractor expenses incurred are not inappropriate given that they relate directly to the review process. The Commission also assessed the confidential information relating to the review consultancies, and has determined that the costs of two consultancies should not be recouped in 2003 revenues. These are:

- Cap Gemini benchmarking report - the objective of this report was to assist GasNet's predecessor to identify major cost factors, areas where its performance is different to other companies and to provide guidance for focusing on business improvement. The report specifically states that it is not a tool that can be used for setting transportation prices and determining precise levels of performance. While this report has been referenced in the review process, it relates primarily to the efficient operation of the GasNet system. Thus, the Commission has concluded that it should be classified as a general operations and maintenance cost accommodated by the expenses allowed for in 2001; and

- Trowbridge self–insurance cost report - while this report was utilised as part of the regulatory review process, the Commission considers that it primarily provides insight into GasNet's general business operations and should also be accommodated by general operations and maintenance expenditure allowances approved in 1998 for 2001.

Thus, the Commission considers that the total allowance for prudent regulatory review costs incurred in 2001 should be $639 278.

The Commission is of the view that these expenses should be adjusted for inflation, and will assume that the expenditures were incurred at the end of each year. This methodology results in total review cost in 2003 dollar terms of $1 051 938.

The Commission considers that GasNet should not incorporate forecast regulatory review costs for 2006 and 2007 in the operations and maintenance cost allowance for the second access arrangement period.

[318] GasNet response to Commission, 30 October 2002.

[319] GasNet response to Commission, 31 October 2002.

Amendment 19

GasNet must amend clause 3.5 of its revised access arrangement information to incorporate regulatory review costs of $1 051 938 in 2003 dollar terms. GasNet must not incorporate forecast regulatory review costs for 2006 and 2007 in benchmark revenues.

Broad cost categories

As discussed in the Draft Decision, the Commission has undertaken an assessment of forecast costs normalised in the four main expense categories and concluded that the proposed amounts are not unreasonable. In addition, GasNet has provided the Commission with key performance indicators (KPIs) relating to forecast operations and maintenance costs in 2003. The Commission has carefully assessed GasNet's performance against available key performance indicators, and concluded that GasNet's proposed benchmark costs do not appear to be unreasonable. A detailed discussion of KPIs is presented in section 10.2 of this Final Decision.

Adjusting GasNet's revised operations and maintenance cost forecasts (as summarised earlier in Table 6.2) for the items mentioned above produces the benchmark costs presented in Table 6.6. However, it should be noted that these values may change slightly due to specific modelling assumptions made by the Commission.

Table 6.6: Indicative operations and maintenance cost forecasts

	$ million				
	2003	**2004**	**2005**	**2006**	**2007**
Pipeline operations	5.96	6.86	6.12	7.42	7.33
Compressor operations	3.29	3.55	3.68	3.72	3.8
General and administrative	8.81	8.16	8.29	8.52	8.69
Fuel gas	1.19	1.28	1.42	1.55	1.69
Total	19.25	19.85	19.51	21.21	21.51

Source: ACCC analysis.

Unsustainability of first period costs

As noted above, a major concern raised by BHP Billiton, EUCV and Amcor and PaperlinX is the claim made by GasNet that savings achieved in the first access arrangement period were unsustainable. The EUCV and BHP Billiton state that costs achieved in the first period should form the basis of assessment of the efficiency cost claims in the second period. Specific issues of contention in relation to first period operations and maintenance costs include the amount of information provided by GasNet; the validity of the claim that part of the decrease in operating costs is the result of the deferral of staff appointments; the claim that the reduction in sales led to substantial reductions in costs; and the potential double payment of costs that may have been deferred from the first period.

The Commission concurs with the EUCV and BHP Billiton that costs achieved in the first period should be used as the basis of any assessment of second period forecasts.

For this reason, the Commission published first period operations and maintenance costs in the Draft Decision document despite GasNet's opposition to the release of this data.[320] In its submissions to the Draft Decision, the EUCV and BHP Billiton stated that the Commission asked for an itemised breakdown of costs but that this has not been provided.[321] The Commission, however, did not require a 'detailed breakdown' of historical operations and maintenance costs. It appears that BHP Billiton and the EUCV may have misconstrued the Commission's requirement for public provision of an 'itemised breakdown' of access arrangement review costs incurred in 2001 and 2002.[322] GasNet provided this information to the Commission in October 2002 and it has been placed on the Commission's website.

Nonetheless, GasNet has agreed to release additional information on operations and maintenance costs incurred in the first access arrangement period. Table 6.7 below denotes first period and 2003 forecast operations and maintenance costs dissagregated into pipeline maintenance, compressor maintenance, general and administrative and fuel gas costs in 2003 dollar terms. The table also shows pigging expenses incurred and forecast to occur, pipeline maintenance costs less pigging as well as general and administrative costs minus exceptional costs.

Table 6.7: Operations and maintenance cost categories, 1998 to 2003

	$ million					
	1998	**1999**	**2000**	**2001**	**2002[c]**	**2003[d]**
Pipeline ops	8.46	6.17	5.39	6.21	6.40	5.96
Pigging				0.76	0.81	0.39
Pipeline ops less pigging	8.46	6.17	5.39	5.45	5.59	5.57
Compressors	4.87	4.31	2.93	2.86	3.12	3.29
G&A[b]	4.74	4.50	3.85	4.08	7.67	8.81
G&A less exceptions	4.74	4.50	3.85	4.08	4.40	5.11
Fuel	1.17	0.83	0.69	0.10	1.47	1.19
Total[b]	19.25	15.81	12.86	14.14	18.65	19.25

Source: GasNet response to Commission, May 2002.
Notes: (a) All 2003 dollars.
(b) Review costs excluded in 2001 and 2002 but included in 2003.
(c) Estimated actual expenditure 2002.
(d) Commission's indicative approved forecast.

Pipeline operations costs

Table 6.7 above illustrates that pipeline operations costs were at their lowest point of $5.39 million in the year 2000, increased to $6.20 million in 2001 and are forecast to be $5.96 million in 2003. Accordingly, between the years 2000 and 2003 there is expected to be an increase in costs of over 10 per cent. However, as the data indicate, a large portion of this increase is attributable to actual and forecast pipeline pigging

320 GasNet considered that this information would be misconstrued.

321 BHP Billiton submission, 11 October 2002, pp. 6; EUCV submission, 9 October 2002, p. 4.

322 ACCC, Draft Decision, 14 August 2002, p. 85.

expenses. When pipeline operations costs excluding pigging are assessed, the increase between the year 2000 and 2003 forecasts is $0.18 million, or three per cent, and the increase between 2001 and 2003 is approximately two per cent.

The Commission requested further information from GasNet substantiating why an increase in pipeline maintenance costs (excluding pigging) above that achieved in 2000 and 2001 is forecast for 2003. GasNet stated that a major restructuring of the pipeline maintenance area occurred prior to 2000. The lower figure in 2000 is related to lower levels of administrative support and temporary delays in reorganising the relevant department following the restructure.[323] The Commission has concluded that these arguments are valid and that the small expected increase in pipeline operations costs is not unreasonable.

Pigging

As noted, a number of submissions suggested that some operations and maintenance cost savings may have been achieved through the deferral of costs, such as pigging, and that an allowance for these costs for the second period would effectively result in a double payment for the same work.

The Commission is aware of no activity other than pigging that may have been deferred in the first access arrangement period. Further, the Commission did not claim in the Draft Decision that pigging activities were actually deferred in the first period, but noted that 'to the extent that pigging operations have been deferred, additional costs would be expected in the second access arrangement period'.[324]

The Commission understands the concern with the potential double payment of pigging costs if this work had been deferred from the first period. However, given that there was no specific budget for pigging made in the original tariff forecasts, it is unable to determine whether the pigging claims made by GasNet for the second access arrangement period incorporate allowances made for the first period. It is for this reason that the Commission requested a schedule of pigging operations from GasNet for the period 2001-2007 for inclusion in the Draft Decision (and this Final Decision). This information will enable interested parties and the Commission to ensure that any allowance for pigging costs made in the third access arrangement period does not duplicate funds that have been allowed for pigging activities in the second access arrangement period. This information can be found in Table 6.3 above.

Compressor maintenance

According to the data provided in Table 6.7 above, compressor maintenance costs are forecast to increase in 2003 dollar terms from $2.86 million in 2001 to $3.29 million in 2003 (representing a real increase of approximately 15 per cent). In response to a request for further information, GasNet argued that 2001 is the low point in the period 1998 to 2007 , and that it is not an appropriate base point for comparison given the

323 GasNet response to Commission, 21 October, 2002.

324 ACCC, Draft Decision, 14 August 2002, p. 84.

lumpiness of GasNet's operating costs and the lumpiness implicit in restructuring programs.[325]

Nonetheless, GasNet identified a number of additional costs incorporated in the forecasts for 2003 which have contributed to this increase. The forecast for 2003 includes provisions for repairs and replacements resulting from random failures of rotating equipment (such as turbines, gear box assemblies and compressor units). It is argued that random failures can occur from time to time despite the implementation of a maintenance program. GasNet has incorporated $0.2 million per year for these potential failures. Other items budgeted for in the second access arrangement period include $0.17 million for the refurbishment of water bath heaters and the inspection of retubing of heat exchangers costing $60 000 per year.[326] These amounts total $0.43 million, which constitutes the total of the increase between 2001 and 2003. The Commission's technical consultant has assessed these claims as being reasonable, given that compressors get more expensive as they age and GasNet has an uneven loading which causes relatively greater wear and tear compared to an unchanging load.

In addition to these costs, GasNet noted in its initial submission that forecasts for the second access arrangement period also include the increasing costs of technical compliance.[327] The Commission's technical consultant confirms that greater technical compliance requirements will have a material impact on GasNet's compressor maintenance costs in the future.

General and administrative costs and fuel gas costs

As the data provided by GasNet illustrate, general and administrative costs are forecast to more than double from $3.85 million in 2000 to $8.81 million in 2003 (in 2003 dollar terms). Much of this increase reflects exceptional costs, namely the increase in insurance costs, listing and governance costs and review costs (see earlier discussion). Net of these costs, the proposed increase between 2000 and 2003 is from $3.85 million to $5.11 million, which equates to an escalation of approximately $1.26 million or 33 per cent.

GasNet has attributed this increase (net of exceptional costs) in part to the increase in marketing costs. As discussed above, the Commission decided to approved an allowance of $0.4 million per year for marketing costs, while according to GasNet expenditure on this cost was negligible in 2000 prior to the hiring of a business development manger in 2001.[328] The increase in costs is also the consequence of a greater allocation of total overheads to the regulated business, to the order of $0.1 million.

GasNet also ascribes this increase in general and administrative costs to the reinstatement of administrative support which was foregone due to warmer weather and consequently low revenues in 1999 and 2000, and delays in filling vacant positions in the first access arrangement period (for the chief financial officer and a back-up system

[325] GasNet response to Commission, 21 October 2002.

[326] ibid.

[327] GasNet submission, 27 March 2002, p. 89.

[328] GasNet response to Commission, 21 October 2002.

planner).[329] The Commission is of the view that the reinstatement of these positions is not inappropriate, particularly given that general and administrative assistance is no longer available from the GPU Inc head office since the GasNet float.

The Commission has considered BHP Billiton's assertion that the K factor mechanism provides GasNet with compensation for reduced gas sales, but offers no relief to users for reduced operations and maintenance expenditure from this gas demand reduction.[330] The Commission notes that the K factor adjustment mechanism is a risk reduction mechanism which guarantees average revenue. It operates independently of any fluctuations in either operations and maintenance costs or total volumes. Unsustainable reductions in operations and maintenance costs from reduced volumes are accounted for by the first period benefit sharing adjustment mechanism, which is discussed in chapter 10 of this Final Decision.

With regard to fuel gas costs, the Commission assessed a model provided by GasNet and determined that the model and the resulting fuel gas estimates are not unreasonable.

Conclusion

The Commission considers that the operations and maintenance costs proposed by GasNet for the second period, subject to the amendments noted above, are not inappropriate. GasNet has provided detailed evidence quantifying and outlining the reasons for the increase in costs between the first and second period, and evidence suggests that these cost increases would be incurred by a prudent service provider acting efficiently (section 8.37 of the Code). Accordingly, it is considered that the cost forecasts would not harm GasNet's legitimate business interests and investment in the covered pipeline (section 2.24(a) of the Code); would encourage the economically efficient operation of the pipeline (section 2.2.4 (d)); and are consistent with the operational and technical requirements necessary for the safe and reliable operation of the pipeline (section 2.24(c)). While the step increase in costs from those incurred in the first period may potentially harm users and prospective users through a corresponding increase in tariffs (section 2.24(f)), no evidence has been provided that this effect should be given greater weight than the negative impact that a reduction in allowed operations and maintenance costs would have on the competing 2.24 factors noted above.

6.2 Other non-capital expenditure

6.2.1 Capital raising costs

Current access arrangement provisions

The current access arrangement provisions implicitly incorporate debt raising costs in the debt margin provided to GasNet. There is currently no provision for equity raising costs.

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329 GasNet submission, 27 March 2002, p. 89.

330 BHP Billiton submission, 11 October 2002, p. 8.

GasNet proposal

GasNet proposed to include capital raising costs as a separate annual non-capital cost payment. Specifically, the company proposed an allowance of $0.5 million per year for equity raisings, and $2.0 million per year to compensate for debt financing costs. GasNet considers that the debt raising costs incorporate the fees and charges associated with debt facilities, and that the equity raising costs represent a proxy for the transaction costs associated with raising equity capital.[331]

Submissions to Issues Paper

BHP Billiton commented that GasNet's capital structure is an issue for GasNet alone, and that a notional capital structure should be used by regulators. BHP Billiton suggested there is a series of cost estimates that compensate the service provider for each core element. It argued that this process inherently allows for capital raising costs facing the firm, and that additional capital raising expenses should not be incorporated in tariffs.[332]

TXU stated that it was 'surprised' at the addition of an annual $2.5 million allowance for capital raising costs.[333]

Draft Decision

In the Draft Decision the Commission considered that, in general, it is reasonable to provide an allowance for debt and equity raising costs.[334] These costs should be determined by reference to reasonable costs facing a benchmark gas transmission or distribution entity.

Debt raising costs

To raise debt, a benchmark service provider has to pay debt-financing costs over and above the debt margin. In the Draft Decision it was noted that an allowance should be provided for arrangement/bank fees. It was noted that while these fees are likely to vary between each debt issue and also over time in line with market conditions, a benchmark needs to be established in order to determine a reasonable allowance for a revenue calculation. According to financial markets a spread of five basis points each year represents an appropriate estimate of fees payable to a bank for the arrangement and distribution of debt.

GasNet claimed that a dealer swap margin was also a valid cost. The Commission agreed that this is a valid cost given that debt providers traditionally provide their funding through a floating interest rate facility but often require companies to enter into hedging arrangements to reduce the extent of interest rate risk.[335] The Commission

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331 ibid., pp. 101-102.

332 BHP Billiton submission, 21 June 2002, p. 24.

333 TXU submission, 31 May 2002, p. 33.

334 Australian regulators have not generally recognised these costs explicitly. Implicitly, they have been included in the debt margin.

335 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, Report for the ACCC, May 2002, pp. 16, 21.

understood at the time that a benchmark swap margin was set at approximately three basis points per year on issued debt.

Other direct costs such as advisory, legal and credit agency costs were also addressed in the Draft Decision. The Commission considered that it is not appropriate to incorporate these costs in the revenue requirement. The Commission was of the view that the external legal and advisory costs are generally negligible for a company when raising debt. Further, it was noted that credit rating costs are generally not required of debt providers. As noted by Macquarie Bank:

> If the project has obtained a credit rating, then Debt Providers will review the rating level and the rationale for the rating provided by the agency. However Debt Providers, particularly bank lenders, do not usually rely on this analysis. The majority of Debt Providers do not delegate their credit decision processes to the credit rating agencies.[336]

It may be argued that a credit rating is necessary for raising debt on capital markets. While this may be true, it was argued that capital market raising represents an alternative to the norm of bank financing for infrastructure. A service provider will use this option (with its associated added costs) only if it is more efficient to do so. The Commission therefore considered that the firm should be responsible for any costs associated with improving on the benchmark, including credit agency costs.

The Commission also assessed costs associated with credit wrapping. Credit wrapping allows a service provider to raise debt based on an AAA credit rating for a fee payable to a credit monoline.[337] By undertaking such an arrangement, a service provider may improve on the benchmark cost of debt and keep the benefits achieved. In the Draft Decision the Commission stated that an allowance for credit wrapping should not be provided to service providers. Regulated businesses are given a benchmark payment to compensate for the cost of debt, and if a company is of the view that it can outperform this benchmark, the costs (and benefits) associated with pursuing this strategy are the responsibility of the company. If the company were to be provided with compensation for credit wrapping costs, this would mean that users effectively incur a cost of debt which is in excess of the benchmark but do not benefit from the payment of the credit wrapping fees. The inclusion of these costs would also distort price signals and might lead to inefficient behaviour by the service provider.

Following the above discussion, the Commission determined that it would be appropriate to provide a benchmark allowance for bank fees and dealer swap margin of a total of 8 basis points per year. The Commission proposed adding this 8 basis points to the debt margin, thus allowing the recovery of this cost through the WACC.

Equity raising costs

As with debt raising costs, the Commission considered it to be appropriate to provide an allowance for equity raising costs. Equity raising costs are required to be paid by an entity when it undertakes capital raising. These costs are paid to equity arrangers for

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336 ibid., p. 12.

337 ibid., p. 9.

services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors.[338]

In the Draft Decision the Commission considered it appropriate to allow service providers to recover gross spreads payable to investment banks and other direct costs associated with raising equity. In the apparent absence of recent Australian empirical data on this issue, the Commission relied on data collected in a paper by Lee et al.[339] According to this paper, the average gross spread payable to investment bankers for an initial public offering of equity is 6.03 per cent for amounts between $US100-199.9 million ($185-$370 million), while the cost of other direct costs such as legal, auditing, printing and registration costs totalled 1.03 per cent. Consequently, the Commission proposed to provide a recovery of 7.06 per cent of equity raised to GasNet for equity raising costs.[340]

Given that equity only needs to be raised once by the company, it was considered appropriate to spread the equity raising cost over the life of the asset. The Commission proposed the recovery of this once-off cost through an annual allowance over the life of the asset (in this instance, 60 years) expressed as a percentage of equity. This has the advantage of increasing the allowance as the capital base increases, reflecting the additional capital raising costs that a benchmark firm would incur. The Commission's calculations indicated that an annual allowance of 48 basis points of equity had the same NPV as the 7.06 per cent benchmark levied in the first year of the asset.[341]

Response to Draft Decision

GasNet stated that the Commission has quoted selectively and out of context from some of its sources relating to the debt margin and cost of debt, and in some cases has not identified sources, particularly in regard to transaction costs. GasNet asserted that debt raising transaction costs can be significant, and that it is inappropriate for the Commission to estimate benchmark transaction costs without adequate sources. It did acknowledge, however, that these costs tend to be confidential and difficult to obtain in the public arena.[342]

GasNet referred to the Commission's exclusion of legal fees associated with debt raising on the grounds that these costs may be negligible. It argued that the Commission's position may be based on a misunderstanding of the extent of the legal and advisory fees that must be paid. GasNet asserted that the borrower must pay its own legal fees as well as the fees of the lender, which can include US counsel and fees for any agent that is involved.[343]

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338 ibid., p. 10.

339 I Lee, S Lochhead, J Ritter, Q Zhao, 'The Cost of Raising Capital', *The Journal of Financial Research*, Spring 1996, p. 62.

340 It is considered that this benchmark number is appropriate for GasNet given that its regulated equity falls within the US$100-199.9 million range (A$185-370 million). The benchmark figure will vary from company to company depending on the level of equity held by the specific entity.

341 Based on a WACC of 6.6 per cent

342 GasNet submission, 20 September 2002, p. 14.

343 ibid., p. 15.

GasNet also addressed the Commission's proposal to not incorporate credit rating costs given that ratings are not required by debt providers. GasNet asserted that lenders rely on credit ratings when assessing the merit of a refinancing facility. It argued that under GasNet's current bond issue and syndicated bank facility the margin paid is dependent on the credit rating of the company, and suggested that this provides evidence that obtaining a credit rating is a compulsory requirement for debt refinancing.[344]

As noted with regard to the debt margin (see section 5.5.2 of this Final Decision), GasNet argued that it is misleading to assume that bank debt is less expensive than capital market debt, and that bank debt is readily available to a benchmark service provider at benchmark margins, or even at all. It is also claimed that borrowers must mitigate refinancing risk by spreading the tenor of loans while at the same time seeking to best match its regulatory period. GasNet stated that all of these decisions have cost consequences.[345]

GasNet stated that it had provided the Commission with a range of quotes that it received for its recent debt raising, and also provided information in relation to fees actually incurred by GasNet on a confidential basis. GasNet considered that a debt raising margin of 30 basis points is reasonable.[346]

The EUCV stated in its submission that a debt margin of 1.20 percentage points adequately compensates the service provider for 'debt acquisition cost'.

No submissions to the Draft Decision commented on the issue of equity raising costs.

Final Decision

Debt raising costs

As noted in its submission to the Draft Decision, GasNet provided the Commission with a range of quotes and the information on the fees that it actually incurred raising debt. While these data have enhanced the Commission's understanding of establishment costs, it is considered inappropriate to use this information directly as the allowed costs should be based on a benchmark gas transmission company, rather than the actual costs facing GasNet.

However, in response to GasNet's comments on the approach taken in the Draft Decision, the Commission has undertaken further research on the issue of debt raising transaction costs. The research has been based on the premise that as with the calculation of the debt margin, the assessment of debt raising transaction costs is essentially an empirical matter that should take into account current market costs. It is noted that this is a new area of analysis and that the Commission will give further consideration to these issues in future regulatory decisions.

For the purposes of the Draft Decision, the Commission referenced a consultancy by Macquarie Bank that set out a number of different upfront costs that may be incurred

[344] ibid.

[345] ibid., pp. 16-17.

[346] ibid., p. 17.

by the service provider each time it refinances or purchases debt.[347] The table below lists these costs and provides a brief definition of each.

Table 6.8: Glossary of debt raising costs

Non-margin financing costs	Definitions
Advisory fees	Fees payable to a financial advisor when arranging debt. A project may also be required to pay legal fees when organising a debt facility.
Agency fee	A fee that is paid to a bond agent who acts as a central point for all information to be distributed to bond holders. It is payable for both bank and capital market facilities.
Arrangement fees	Upfront fees required to be paid to banks or capital market dealers for the arrangement of debt. These fees often incorporate syndication costs and underwriting fees.
Credit rating costs	Upfront and annual fees that are payable if a project obtains a credit rating.
Dealer swap margin	A dealer swap margin is payable to the financial institution for swapping from a floating to fixed rate facility.
Syndication costs	Fees that are required to be paid on bank arranged debt when a number of banks provide funds to the facility. Syndication costs are typically incorporated in arrangement fees and are often known as participation fees. They are known as placement fees in the context of capital market facilities.

Source: Macquarie Bank, May 2002, p. 21; discussion with industry analysts.

While the Macquarie Bank report noted these potential costs, it did not quantify benchmark amounts for the cost categories raised. The Commission has further assessed these costs through discussions with a number of industry analysts, and undertaken further research in order to assess the validity of these costs and to acquire market estimates for these expenses.

The Commission contacted Westpac Institutional Bank which provided detailed information on the transaction costs associated with capital market raisings.[348] According to Westpac, the cost categories noted in Table 6.8 represent valid expenses incurred when raising debt. These expenses include credit rating, agency and legal costs. The Commission did not provide an allowance for these expenses in the Draft Decision. These categories are in addition to the credit spread over swap.

Westpac stated that while transaction costs are likely to vary between issues, on average the costs shown in Table 6.9 a service provider would currently be incurred for a corporate five year bond raising. These costs were quoted by Westpac in either dollar

[347] Macquarie Bank, *Issues for Debt and Equity Providers in Assessing Greenfields Gas Pipelines*, May 2002.

[348] In addition, Westpac Institutional Bank provided advice to SPI PowerNet in relation to these issues. See Appendix F, SPI PowerNet Revenue Cap Application, 11 April 2002, p. 41.

or basis point terms. Any fees quoted in dollar terms were converted into basis points by the Commission for consistency purposes.[349]

Table 6.9: Debt raising cost estimates by Westpac

Non-margin financing fee	Westpac estimate	Commission calculations (basis points per year)[a]
Agency fee	$5-10,000 per annum	0.3
Arranger fee	$50 000 per debt issue	0.4
Credit rating fees	$30-40,000 per annum	1.2
Dealer swap margin	5 basis points per annum	5
Legal fees	$50 000 - $100 000 per debt issue	0.6
Placement fee	5 basis points per annum	5
Total		12.5

Source: Westpac Institutional Bank and ACCC analysis.
Note: (a) Use the mid-point of these ranges in the calculation.

As indicated in the above Table 6.9, information provided by Westpac suggests that 12.5 basis points represents current market establishment fees facing a benchmark service provider raising debt on capital markets.

Letters submitted in September and October 2002 by ANZ Investment Bank, National Australia Bank and the Commonwealth Bank on behalf of ElectraNet SA suggests that transaction fees associated with capital market debt facilities may actually be lower than that suggested by Westpac.[350] According to National Australia Bank, total fees of between 8 and 8.5 basis points are payable per year , made up of a placement (dealer) fee of 7 basis points, and legal documentation and Austraclear (agency) fees of between 1-1.5 basis points.[351] ANZ Investment Bank suggests fees of 8 basis points or greater, incorporating 5 basis points for dealer fees and at least 3 basis points for incidental fees such as arrangement costs, legal fees, agency and settlement fees.[352] The Commonwealth Bank indicated a benchmark of 5 basis points payable to lead managers and 3 basis points for establishment expenses.[353]

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349 When quoted in dollar terms, these fees were converted by the Commission into annual percentage rates by dividing transaction costs by the regulated level of debt held by GasNet ($0.6 \times$ \$494.2 million), and amortising the calculated figure over five years.

350 ElectraNet SA revenue cap application submission, 11 October 2002. Westpac Investment Bank also submitted a letter to ElectraNet on these issues. This letter proposed total annual transaction fees of 12 basis points, which was made up of 4 basis points for a swap margin and 8 basis points for placement fees for a BBB+ entity.

351 Letter from George Polites, National Australia Bank Limited, to Mr Geoff Teitzel, ElectraNet SA, 26 September 2002.

352 Advice from Damon Colbert, ANZ Investment Bank to ElectraNet Pty Ltd, 3 October 2002.

353 Letter from Peter Harrington, Commonwealth Bank of Australia to Mr Geoff Teitzel, ElectraNet SA, 24 September 2002.

With regard to bank issued debt, *Basis Point*, a financial market journal published by Reuters, provides a number of Australian bank debt raising case studies each week, many of which discuss transaction fees. This journal employs various terms to describe debt raising transaction costs which differ to those noted by Macquarie Bank, such as 'top-level front-end fees' and 'top level all-ins'. Through discussion with industry analysts, the Commission understands that the term 'top-level front-end fees' referenced by *Basis Point* represents the total fees paid to the lead managers participating in the facility. That is, these fees are equivalent to syndication or placement fees. The term 'top-level all ins' includes syndication costs as well as arranger fees. None of these fees incorporate legal, agency, credit rating costs or a dealer swap margin.

Table 6.10 below summarises top-level front-end fees as noted in Issues 497 and 498 of *Basis Point* from September 2002. The table also lists these establishment fees in basis point terms per year as calculated by the Commission.[354]

Table 6.10: Front-end bank fees

Facility	Type	Fees[a]	Amount	Tenor (duration)	Basis points per year[b]
PaperlinX	Refinancing	20-40 bps front-end fee	$300m	3-5 years	6 to 12 bps
Australian Magnesium	Project financing	75 to 100 bps top level front end fee	$890m	10 years	10 to 14 bps
TM Energy	Project financing	50 bps top level front end fee	$225m	15 years	5 bps

Source: *Basis Point*, Issue 497, 7 September 2002, and Issue 498, 14 September 2002.
Notes: (a) basis points per issue.
(b) ACCC analysis.

As the table illustrates, front-end (syndication fees) for the above facilities tend to vary significantly, but appear to fall in the range of between 5 to 14 basis points per year. This compares to 5 basis points estimated by Westpac for the equivalent placement fees associated with capital market-issued facilities. In addition, information relating to a United Energy debt issue published in *Basis Point* suggests an all-in fee (which includes syndication and arrangement fees) of 17 basis points per year.

Unfortunately, benchmark estimates of lead arranger, dealer swap margin, legal, credit rating and agency fees for bank raised debt were not available to the Commission for the purposes of this decision. Thus, while evidence tends to suggest that the transaction costs associated with bank issued debt may be higher than debt issued on capital markets, this is unclear given the absence of authoritative data and limited observations.

[354] These estimates were calculated through amortising the total establishment fees across the tenor of the agreement (using a discount rate of 6.3 per cent) and dividing these amounts by the total value of the loan.

The Commission considers that on balance it is appropriate to use the 12.5 basis points derived from the information provided by Westpac as an estimate of current transaction costs associated with raising debt. The data incorporate all of the costs considered by Macquarie Bank to be valid debt raising expenses and are sourced from a credible entity that has also provided guidance to SPI PowerNet and ElectraNet SA on these issues. While limited available evidence suggests that bank debt costs may be higher than capital market costs, the Westpac data provide an appropriate proxy given the absence of detailed information relating to bank debt and is at the higher end of the range of estimates relating to capital markets.

Given an opening regulated asset base of $494.2 million in 2003 and a benchmark gearing ratio of 60:40, the 12.5 basis points allowance for capital raising costs effectively provides GasNet with $370 650 in 2003 for these expenses. This compares with $2 million per year proposed by GasNet in its proposed revised access arrangement information and 30 basis points (or $886 860 in 2003) proposed in GasNet's submission to the Draft Decision.

The Commission is of the view that the use of estimates of current market transaction costs facing a benchmark service provider is consistent with the objective of replicating the outcome of a competitive market. This would be expected to promote the economically efficient operation of the pipeline (section 2.24(d) of the Code) and also be in the public interest, including the public interest in having competitive markets (section 2.24(e)).

The Commission does not agree with the assertion by the EUCV that a debt margin of 1.20 adequately compensates GasNet for debt acquisition costs. The addition of debt raising costs to the debt margin generates a total cost of debt of 158.5 basis points (see section 5.5.2 of this Final Decision). This parameter value was calculated using current market evidence and thus provides adequate compensation for total debt costs as opposed to the 120 basis points proposed by the EUCV. No other comments were presented by users and interested parties on this issue. The Commission therefore concludes that a debt transaction cost allowance of 12.5 basis points is not counter to the legitimate interest of users and prospective users (section 2.24(f) of the Code).

With regard to the business interests of the service provider and investment in the pipeline, (section 2.24(a) of the Code) the Commission maintains that the adoption of benchmark costs is appropriate. The use of benchmarks should encourage efficient behaviour as it allows the service provider to structure its debt to achieve least cost financing options.

Equity raising costs

The Commission acknowledges that there are two different viewpoints with regard to the validity of providing an allowance for equity raising costs. One viewpoint is that the initial capital base of a regulated entity incorporates all capital costs, suggesting that no additional payment is required for equity raising. A second perspective is that the initial capital base only measures the value of physical assets, and therefore does not compensate the service provider for raising expenses. The Commission considers that both models have merit, although on balance it considers that the second model better reflects the process used to determine the capital base for GasNet. Consequently, the Commission maintains its position that it is reasonable to provide an allowance for equity raising costs, as these costs are required to be paid by an entity when it undertakes capital raising. It does not consider that they have been incorporated in GasNet's capital base.

In the Draft Decision, reference was made to a paper by Lee et al which provides benchmark numbers on the cost of raising equity in the United States. This paper suggested that the average gross spread payable to investment bankers for an initial public offering of equity was 6.03 per cent and that an additional 1.03 per cent is required to be paid for other direct costs such as legal, printing, auditing, and registration costs. Since the Draft Decision, the Commission has undertaken further research on this issue and has collected recent Australian data relating to equity raising costs. Specifically, information on equity raising costs for several major Australian infrastructure equity raisings has been sourced, the details of which are presented in Table 6.11.

Table 6.11: Recent Australian equity raising costs

	Date of offer	Details of offer	Raising costs ($ millions)	Total offer ($ millions)	Fees (per cent of total offer)	Fees (per cent per year)[d]
United Energy	March 1998	IPO – stapled securities	20[a]	968.2	2.1	0.130
Macquarie Communications Infrastructure Group	July 2002	IPO – stapled securities	13	310	4.2	0.264
Australian Pipeline Trust	May 2000	IPO – units	12	488	2.5	0.155
Envestra	July 1999	Rights offer, convertible notes and placement issue	10.1[b]	310	3.258	0.205
GasNet	October 2001	IPO – Units	15[c]	260.16	5.77	0.363
Average			14.02	467.27	3.548	0.224

Source: Company prospectuses; ACCC analysis.

Notes: (a) includes underwriting fees, selling fees, advisory fees, legal fees, accounting fees, printing, advertising and other expenses.

(b) includes underwriting fees, advisory fees, legal fees, accounting fees, printing, advertising, stand duty and other expenses.

(c) includes the Joint Lead Manager's commissions and fees, accounting fees, legal fees, lodgement fees, listing fees, fees for other advisers, prospectus design, printing and other miscellaneous expenses (including taxes and other government charges).

(d) amortised in perpetuity using a real vanilla WACC of 6.3 per cent.

Equity raising costs for the Australian infrastructure equity issues noted above fall in the range of 2.1 to 5.77 per cent of total equity raised. Amortised in perpetuity, this amounts to costs of between 0.130 and 0.363 per cent of equity raised.

The Commission considers that an average of these annual costs represents an appropriate Australian benchmark for the purposes of this decision. Thus, it has decided that equity raising costs of 0.224 per cent per year of regulated equity should be used. This compares to 0.48 per cent calculated in the Draft Decision using US sourced data. With a regulated asset base of $494.2 million and the assumed gearing ratio of 60:40, this amounts to a payment in 2003 of $442 803 in 2003 for these costs. GasNet proposed an allowance of $500 000 per year in its revised access arrangement information for equity raising expenses.

No submissions to the Draft Decision commented on this issue. As with debt raising costs, the Commission intends to undertake further research on this issue for future regulatory decisions.

Amendment 20

GasNet must amend section 3 of its revised access arrangement information to include an allowance for equity raising costs of 0.224 per cent of regulated equity, to be recovered as an annual non-capital cost cash flow. It must also amend its revised access arrangement to exclude an allowance for debt raising costs in non-capital expenditure cash flows and add 12.5 basis points to the debt margin for these costs.

6.2.2 K factor

Current access arrangement provisions

The access arrangement as it currently stands includes a provision for a K factor adjustment. If the average tariff achieved is different to the average benchmark tariff, future tariffs are adjusted to allow the under-recovery (over-recovery) to be recovered (paid back to users) in the next regulatory year. This does not affect GasNet's incentive to grow the market, as the average tariff is not affected by absolute changes in volumes – it is only affected by changes in the product mix.[355]

Schedule 5 of the Tariff Order sets out the details of the K factor adjustment as part of the transmission price control formulae. Schedule 5 also specifies a rebalancing control formula for individual tariffs. The current access arrangement provisions allow for an increase in individual tariffs by up to one per cent (above the CPI-X formula) per year.

The Commission must assess the proposed tariff adjustment towards the end of each calendar year. The new tariffs are implemented from 1 January of the subsequent year. As GasNet must propose its next tariff before full year performance is known, its calculations can be based on actual data for most of the year but include an estimate for the last part of the year. Differences between this estimate and actual performance are corrected as part of the tariff adjustment for the subsequent year.

[355] For example, if volume decreases in zones which are charged high tariffs and volumes increase in zones which charge lower tariffs, the overall volumes may not change but the total revenue will be less than before. The K factor is designed to compensate for this possibility.

GasNet proposal

During the first access arrangement period, differences between the forecast and actual product mixes resulted in a shortfall in GasNet's average revenue. While the K factor adjustment allows for an increase in the maximum average tariff (above the CPI-X formula) in the year following such a shortfall, the current limitation on increases in individual tariffs of one per cent per year (above CPI-X) restricted the amount of the shortfall that GasNet could recover in the initial access arrangement period.[356]

In its proposed revised access arrangement GasNet proposed rolling forward the portion of the K factor shortfall which was unrecovered in the first access arrangement period. It estimated a total shortfall of $14 million (2002 dollar terms) which GasNet escalated for inclusion in the revenue model in 2003. The 2002 dollar figure comprised the calculated estimated cumulative shortfall of $10 359 839 for the period 1998 to 2001 and an estimated additional K factor shortfall in 2002 of approximately $3.6 million.[357]

GasNet proposed maintaining the K factor adjustment mechanism for the second access arrangement period but amending the cap on individual tariffs. Schedule 4 of the revised access arrangement puts forward changes to the rebalancing control formula to allow recovery (pay back) in full of the calculated K factor in the year immediately subsequent to the under-recovery (over-recovery). Additionally, it is proposed in Schedule 4 that the rebalancing control formula be amended to allow individual tariff changes up to two per cent above CPI-X plus K factor adjustment, compared to one per cent above CPI-X in the current access arrangement provisions.[358]

Submissions to Issues Paper

Origin stated that it is not seeking a change to the general K factor approach, but considered that it is inappropriate to allow the K factor adjustment to occur without constraints. Origin raised a number of issues with the K factor proposal put forward by GasNet. One concern was that the K factor does not take into account the changes to a retailer's aggregate load characteristics that may result from the implementation of full retail contestability. Origin added that the proposed approach for the second access arrangement period transfers a substantial degree of risk to users of the system. Furthermore, Origin highlighted its concern that the K factor allows GasNet to achieve higher than forecast total revenues while applying for an increase in tariffs in the future as a consequence of the operation of the K factor adjustment.[359]

TXU was concerned that there is potential for the GasNet proposal to generate price shocks through the additional ability to rebalance tariffs. TXU argued that the K factor recovery should be linked to an appropriate constraint on rebalancing tariffs that limits the scope for individual tariff adjustment. Another concern was that the proposed price

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356 GasNet access arrangement information, 27 March 2002, p. 10.

357 At the 2001 annual tariff review, the cumulative K factor recovery shortfall was estimated to be $11 053 909 in 2002 dollars. It was estimated that the company would recover $694 070 of this through the maximum allowable increase in tariffs in 2002. As a result GasNet has an estimated cumulative K factor under-recovery of $10 359 839 (in 2002 dollars).

358 GasNet access arrangement, 27 March 2002, pp. 33-38.

359 Origin submission, 17 May 2002, pp. 3-4.

control formula shifts the risk of differences between changes in demand assumptions and actual demand from GasNet onto users, and does not recognise possible changes in load characteristics of retailers as the competitive market develops. TXU also stated that it was unable to determine what incentives the K factor adjustment has on the behaviour of GasNet, and that the proposed price control formula allows GasNet to earn more than its revenue requirement for reasons outside of its control. It also commented that GasNet should either seek roll-in of the Southwest Pipeline, or propose a price control formula that separates the Southwest Pipeline tariffs from the rest of the PTS tariffs.[360]

BHP Billiton expressed the following concerns with the proposed K factor approach:

- it may allow for windfall gains for GasNet through allowance for a K factor adjustment even at times of increasing volumes and revenues;
- there is potential under the K factor for cross-subsidies to be built into the tariff structure and thus the removal of cost reflectivity; and
- care needs to be taken with regard to the K factor adjustments relating to the Southwest Pipeline and the WTS.

To ameliorate these concerns, BHP Billiton proposed a different K factor mechanism. Under this model, each withdrawal and injection zone would be ring fenced, and a K factor correction would be calculated for each zone. However, BHP Billiton recognised that this approach may be impractical, and suggested as an alternative calculating a K factor adjustment for each injection zone and a single K factor calculated for all withdrawal zones.

BHP Billiton also noted that the K factor adjustment removes some risk from GasNet and places it with users. It considered that the WACC for GasNet should reflect this risk reduction. Further, in view of its concerns that this mechanism could lead to subsidisation, BHP Billiton requested that GasNet demonstrate the cost allocation method between zones and reveal the costs used to develop the tariffs in each zone.[361]

ACG recommended that a separate price control should operate in respect of the Southwest Pipeline assets, and that 'any K factor in the price control should be quarantined to future SWP tariffs'.[362] ACG also recommended that GasNet be required to establish a redundant capital policy that would require the value associated with the Southwest Pipeline assets to be written down to the extent necessary to permit the costs to be borne by users of the Southwest Pipeline.[363]

Pulse was concerned about the proposed increase in tariffs in the first year of the second access arrangement period, and suggested that this is in part a consequence of the lump sum claim for the K factor carryover. Pulse submitted that the 'lump sums

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360 TXU submission, 31 May 2002, pp. 34-35.

361 BHP Billiton submission, 18 July 2002, pp. 2-4.

362 ACG, *Implementation of incremental pricing of the Southwest Pipeline*, (ExxonMobil submission, 5 June 2002), p. 23.

363 ibid., p. 24.

associated with efficiency gains and K factor carryovers should be treated as annuities over the life of the second access arrangement'.[364]

Draft Decision

The Draft Decision discussed three separate issues relating to the K factor: the recovery of the K factor shortfall from the first period; the individual tariff rebalancing mechanism; and the proposed ring-fencing of new facility investments from the K factor adjustment. This section will briefly outline the Commission's position on these issues put forward in the Draft Decision document.

Recovery of the K factor carryover from the first access arrangement period

The Commission stated in its Draft Decision that GasNet should be able to recover the shortfall it suffered due to constraints in the individual tariff rebalancing control during the first period through an allowance in its benchmark revenues for the second period. The Commission proposed a mechanism whereby the estimated cumulative shortfall for 1998-2001 of $10 359 839 (2002 dollars) is recovered in benchmark revenues for 2003-2007. The estimated additional shortfall for 2002, calculated at the end of 2002, would then be recovered through an adjustment to 2003 tariffs. This would effectively mean that actual tariffs for 2003 would be different to those set out in the Final Decision document. Any difference that may occur between the 2002 K factor carryover estimate and actual performance would then be corrected as part of the tariff adjustment commencing in January 2004.

Individual rebalancing mechanism

In the Draft Decision the Commission agreed that the K factor mechanism should be maintained in the forthcoming access arrangement period. The Commission also agreed in principle with GasNet's proposal to change the rebalancing control formula for individual tariffs which allows total recovery of any shortfall in the subsequent year of the access arrangement period, as well as any shortfall of average tariffs that is expected in the current year. However, it considered that the proposed rise in the maximum increase for individual tariffs from one to two per cent above the average increase would not be appropriate. This is because the shift could give GasNet undue scope to rebalance tariffs during the access arrangement period, with the potential to substantially reduce the cost-reflectivity of tariffs established through the current revisions approval process.

Operation of K factor adjustment

As noted above, a number of submissions raised additional concerns in relation to GasNet's proposal.

BHP Billiton and Origin expressed concern that in some instances GasNet may achieve higher than forecast total volumes and thus revenues, and still apply for a K factor adjustment if average revenues decrease.[365] The Commission notes that equally, GasNet could achieve lower than forecast volumes and still be required to pay back a K

[364] Pulse submission, 16 May 2002, p. 5.

[365] BHP Billiton submission, 18 July 2002, p. 2; Origin submission 17 May 2002, p. 4.

factor adjustment. The Commission considers that such an outcome is consistent with the operation of the K factor, and that no amendments should be made to prevent this result. The K factor mechanism is intended to address changes in average revenue (either positive or negative) independently of any changes in total volumes that may occur simultaneously.

Pulse commented on the contribution to the proposed 38 per cent increase in tariffs between 2002 and 2003 made by the lump sum K factor, and suggested that this lump sum amount should be treated as an annuity over the access arrangement period. The Commission noted that the K factor carryover is already proposed to be spread across the second period, and that the Commission proposed to maintain this approach and distribute the relevant K factor carryover using the tariff levelisation approach.

Ring fencing of new facilities investment

The Commission acknowledged the concerns raised by BHP Billiton, TXU and ACG and noted that it considers that GasNet's K factor proposal may potentially defeat the purpose of the economic feasibility test of the Code (section 8.16(b)). Under the economic feasibility test, a new facilities investment can only be included in the capital base if the anticipated revenue generated by the facility exceeds the cost of the investment. If volumes experienced on the new asset fall short of expected volumes once it is rolled into the asset base, then the asset would effectively not recover its costs. However, with a K factor mechanism, part of its costs could be recovered from users of other services. That is, customers from other zones would effectively cross-subsidise the cost of the new asset for outturn volumes being less than anticipated.

The Commission noted that it considers that it would be undesirable for the operation of the K factor adjustment to potentially override the cost reflective nature of the tariffs to apply after 2002. It considered that the application of the general K factor mechanism to new assets included under the economic feasibility test may not be appropriate given volume uncertainty and the potential for substantial cross-subsidisation.

The Commission carefully assessed the alternative models suggested by BHP Billiton. It also considered a simpler approach which would ring fence extensions to the PTS from the general K factor adjustment. For example, the portion of the Southwest Pipeline included under the economic feasibility test, the WTS, the Murray Valley Pipeline and any future extensions included under the section 8.16(b) test could be ring fenced.

While the Commission was concerned at the potential loss of cost-reflectivity through the operation of the K factor mechanism it noted that each of the ring fencing models assessed would be likely to generate considerable complexity and uncertainty. The Commission identified a number of difficulties and considerations relevant to the ring fencing proposals:

- users could be subject to substantial and frequent major tariff shocks;
- additional complexity may increase compliance costs (which are ultimately borne by users and end-users) and reduce transparency — users and end-users of the PTS already find the tariff structure complex;

- there may be grounds for treating quarantined investments as independent pipelines;
- a sharing of costs would still occur at the scheduled review; and
- regardless of whether there is a K factor adjustment, tariffs will move away from the level of cost reflectivity assumed when the access arrangement (or revised access arrangement) was approved whenever there is a difference between the expected and actual product mix (or costs) within an access arrangement period.

On balance, the Commission concluded in its Draft Decision that it did not consider that it would be technically and commercially reasonable to require GasNet to isolate certain assets to the extent necessary to prevent the potential for cross-subsidisation.

Response to Draft Decision

In its submission to the Draft Decision, GasNet responded to the Commission's proposal to recover the estimated K factor calculated for 1999-2001 in 2003-2007 tariffs, plus an adjustment to the annual tariffs set for 2003 to reflect the 2002 K factor carryover. GasNet maintained that the better approach is to use the cumulative K factor balance calculated at then end of 2002 as the input into 2003-2007 tariffs. GasNet noted that in practice this methodology will result in almost the same tariffs for 2003 as would have been calculated using the Commission's two step proposal, and that under this methodology the tariffs approved by the Commission will be exactly equal to those charged in 2003. It also noted that under the GasNet approach there is no need to forecast the proportion of the 2001 closing K factor balance that will be recovered in 2002 and compare this against the amount actually recovered in that year.[366]

GasNet further clarified the operation of the K factor adjustment mechanism proposed. It is indicated that there is still a requirement to calculate the K_{tb} balance for 2002 when 2004 tariffs are set at the end of 2003. Further, it suggested that the value of the K factor calculated for the end of 2002 must have the interest factor applied to it for the purposes of determining the opening balance for 2003 tariffs. Additionally, GasNet argued that the opening figure needs to be escalated again to reflect the cash flow timing assumed in the revenue model, which assumes receipt of funds at the end of the year.[367]

GasNet advised that it does not propose to calculate the estimated balance at the end of 2002 until it receives volume data for the winter period in late October. It suggests that for any calculations that the Commission may wish to undertake before the final value is known, GasNet's best estimate for the opening balance for 2003 is $14 million.[368]

GasNet also responded to the individual tariff rebalancing mechanism proposed by the Commission. GasNet maintained its position that it is appropriate to retain flexibility to rebalance the relative weights of tariffs and that it is therefore reasonable to set the

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366 GasNet submission, 20 September 2002, p. 25.

367 ibid., pp. 25-26.

368 ibid., p. 26.

proposed increase to two percent above the proposed adjustment, rather than one per cent proposed in the Draft Decision.[369]

In its submission to the Draft Decision, Origin stated that the K factor adjustment mechanism put forward by GasNet for the second access arrangement period 'has the potential to generate annual price shocks by allowing volatility through the K factor recovery of GasNet's revenue requirement'. It noted that the substantial K factor carryover from the first period was the consequence of incorrect volume forecasts and that these inaccuracies should have been corrected for the second access arrangement period. Origin states that the ability to pass through any individual tariff increase is limited given that Victorian gas retailers are currently subject to maximum uniform tariff control for small users. Origin therefore supported a constrained tariff rebalancing K factor (for under-recovery) whereby the total increase in individual tariffs does not exceed the CPI, unless the CPI exceeds an agreed benchmark. In this submission, Origin referred to the Draft Decision where the Commission noted that while GasNet could achieve higher than forecast total volumes and still apply for a K factor adjustment if average revenues decrease, the opposite could also be true. Origin responded that this reverse situation might occur but that it was unlikely, suggesting that the total demand forecasts were conservative.[370]

In its submission to the Draft Decision, TXU reiterated its concern with the individual tariff rebalancing mechanism. TXU considered that the ability to pass through the full extent of the under-recovery and an additional one per cent adjustment is likely to result in retail price shocks that are unacceptable. Moreover, given that Victorian retailers are subject to deemed/default contract provisions and thus may not be able to pass through increases. It submitted that the Commission's proposal shifts risk to retailers from GasNet. TXU added that retailers generally have limited working capital to fund any shortfalls that may occur. In light of these concerns, TXU proposed that 'any K factor recovery must be subject to a rebalancing constraint on tariffs in order to avoid retail price shock'.[371]

TXU asserted in its second submission that the Commission's Draft Decision is inconsistent with its VENCorp Decision as the latter provides for price certainty rather than volatility. It also noted that a large K factor is unlikely for the second period as the volume forecast bias present in the first period has been amended in GasNet's revised access arrangement. With regard to the additional one per cent increase in individual tariffs proposed by the Commission, TXU advocated an increase limited to X per cent, where X is equal to the value proposed for the tariff path. This would effectively mean that the overall individual tariff increase is capped at CPI.[372]

Amcor and PaperlinX, in their submission to the Draft Decision, stated that the acceptance of the K factor opens up the opportunity for cross-subsidisation of the Southwest Pipeline should volumes fall short of forecasts. Amcor and PaperlinX stated that the Commission has accepted inclusion of the Southwest Pipeline without adequate

[369] ibid.

[370] Origin submission, 18 September 2002, pp. 3-4.

[371] TXU submission, 16 September 2002, p. 1

[372] ibid., pp. 1-2

examination of the costs involved. They argued that PTS users may make additional and uncontrolled contributions to the Southwest Pipeline if it is not ring-fenced from the K factor.[373]

In its comments in response to the Commission's Draft Decision, the EUCV raised concerns that the K factor adjustment mechanism may 'provide an even greater but unseen contribution to any under recovery of the Southwest Pipeline'.[374]

In its submission to the Draft Decision, BHP Billiton stated that by including the Southwest Pipeline in the K factor calculation, under-runs on the Southwest Pipeline can be added to PTS tariffs thereby increasing the benefit to GasNet from the inclusion of the pipeline. BHP Billiton asserted that the opportunity to gain further benefits for the Southwest Pipeline should be eliminated. Furthermore, it argued that complexity is not a valid argument for incorporating the Southwest Pipeline in the K factor given that such a decision moves tariffs away from cost reflectivity. BHP Billiton stated that regulators of more complex systems have successfully applied cost-reflective principles in their decisions, and that the Commission should quantify the costs of complexity rather than simply accepting this argument.[375]

The EUAA argued that there should be no underlying cross-subsidisation between the Southwest Pipeline, the PTS and the WTS. It stated that 'cross-subsidies would be inappropriate and inconsistent with regulatory reform in energy' and 'GasNet needs to detail how it prevents any under or over-run of revenue from these two elements'.[376]

Final Decision

In response to BHP Billiton's comment that GasNet could achieve higher than forecast total volumes and still apply for a K factor adjustment if average revenues decrease, the Commission noted that the opposite could also be true. Origin responded that this opposite scenario was unlikely. The Commission considers that the validity of the K factor mechanism is not challenged by the fact that either of these scenarios could occur. It does not agree with Origin's suggestion that the demand forecasts are biased downwards and that GasNet is likely to achieve greater than forecast throughput.

The Commission reiterates its comment in the Draft Decision that the K factor mechanism is intended to adjust for changes in average revenue. This is independent of any changes in total volumes that may occur simultaneously. The risks associated with changes in total volumes are borne completely by GasNet.

Recovery of the K factor carryover from the first access arrangement period

In its submission to the Draft Decision, GasNet stated that it would be appropriate to use the K factor balance at the end of 2002 as the input into the 2003-2007 tariffs. It argues that this approach has the advantage that the tariffs approved by the Commission in the Final Decision will be exactly those charged in 2003.

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[373] Amcor and PaperlinX submission, 13 September 2002, pp. 8-9.

[374] EUCV submission, 13 September 2002, p. 11.

[375] BHP Billiton submission, 13 September 2002, pp. 9-10.

[376] EUAA submission, 20 September 2002, p. 2.

After further consideration, the Commission concurs with GasNet that it is appropriate to use the K factor balance available at the end of 2002. GasNet has provided the Commission with its calculations and these have been assessed. Based on this assessment, the Commission considers that a cumulative K factor carryover of $12 903 127 in 2003 dollar terms is appropriate and should be added into 2003-2007 tariffs. The Commission notes that, with GasNet's approach to calculating the tariff path over the access arrangement period, the collection of the sum will be made over the five years (as Pulse suggested).

In its submission to the Draft Decision, GasNet proposed escalating the 2003 K factor amount by an interest factor to reflect the cash-flow timing assumed in the revenue model. The Commission, however, does not agree that an additional escalation is required. This is because the revenue model is based on the assumption that costs are incurred at the end each year, meaning that an additional escalation would constitute a double counting.

GasNet states that with this methodology there is still a requirement to calculate the K_{tb} balance for 2002 when 2004 tariffs are being set at the end of 2003. The Commission agrees that this adjustment is appropriate and should be undertaken in 2003.

Amendment 21

GasNet must amend section 3.5 of its revised access arrangement information so that the estimated K factor under-recovery to be carried forward is $12 903 127 in 2003 dollar terms.

Individual tariff rebalancing mechanism

As noted above, the Commission proposed in the Draft Decision to agree to an individual tariff rebalancing mechanism that allows total recovery of any K factor shortfall incurred in the previous year. It was also proposed that individual tariffs could increase by an additional one per cent, provided that the forecast average tariff does not exceed the maximum allowed tariff. This equates to an individual tariff adjustment mechanism of CPI-X+K+1 per cent, where K represents the individual tariff adjustment for any under or over-recovery in the previous year. In its response to the Draft Decision, GasNet maintained that individual tariffs should be allowed to increase two per cent above the proposed K factor adjustment.[377]

In contrast, a number of submissions from interested parties reiterated and clarified concern with the proposed individual tariff rebalancing formula. A number of criticisms were raised by Origin and TXU:

- it may lead to an increase in tariff shock and volatility for users;
- it generates a transfer of product mix risk from GasNet to users, as users may not be able to pass through any potential increases in costs; and
- users may not be able to fund any shortfalls that may occur as users have limited working capital.

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377 GasNet submission, 20 September 2002, p. 26.

Origin and TXU both propose as an alternative a constrained tariff rebalancing K factor whereby the individual tariff increase is capped at CPI.

Upon further consideration, the Commission accepts Origin and TXU's claims that the proposed adjustment to the individual tariff rebalancing mechanism each year may generate substantial costs for users. Such a mechanism may increase tariff volatility and also generate a transfer of product mix risk to users that are in less of a position to contend with this risk than GasNet. Accordingly, the Commission considers that GasNet's proposed individual tariff adjustment (Step 2 of clause 4.9 of the proposed revised access arrangement) is not in the interests of users or the public more generally (see section 2.24(e) and (f) of the Code).

The Commission is of the view that it is more appropriate to allow for an increase of individual tariffs by CPI-X+2 per cent per year to compensate (payback) any K factor balance**.** This allows for an additional one per cent increase in individual tariffs compared to what is allowed under the current access arrangement. As has occurred in the first access arrangement period, the Commission will allow for the accumulation of any over or under-recovery throughout the period. Should an imbalance be present at the end of the access arrangement period, an adjustment will be made to tariffs in the third access arrangement period to recover (payback) the funds.

The Commission considers that this proposal is not inconsistent with GasNet's legitimate business interests and investments (section 2.24(a) of the Code). It should provide adequate scope for GasNet to recover any over or under recovery that may eventuate, particularly given that it is unlikely that there will be a large K factor in the second period as incorrect product mix forecasts prevalent in the first period should have been corrected for in the second access arrangement period.

Amendment 22

GasNet must amend clause 4.9 of Schedule 4 of its proposed revised access arrangement to remove 'Step 2' of the rebalancing control formula.

Ring fencing of new facilities investment

As noted by the Commission in the Draft Decision, the inclusion of extensions to the PTS in the K factor calculations has the potential to defeat the purpose of the economic feasibility test. Under the economic feasibility test, a new facilities investment can only be included in the capital base if the anticipated revenue generated by the facility exceeds the cost of the investment. If volumes fall short of those forecast then the asset may not recover its costs. Inclusion of the asset in the K factor mechanism could allow partial recovery of the shortfall. As noted in the Draft Decision, the Commission considers it undesirable for the operation of the K factor to potentially result in new extensions being cross-subsidised by users of the existing system (see section 8.2(c)). This is not in the interests of users or prospective users (section 2.24(f)).

In the Draft Decision the Commission decided it was not technically and commercially reasonable to require GasNet to isolate certain assets from the K factor calculation in order to prevent potential cross-subsidisation. As part of its ongoing assessment of the access arrangement, and in response to the substantial criticism by interested parties of the Draft Decision, the Commission has reassessed this position. Further analysis has indicated that the additional complexity to the K factor calculation is not as significant as first thought, and would not outweigh the benefits of isolating new extensions. Nor will isolating these assets in the calculation of tariffs at the scheduled reviews be difficult. Isolation of these assets at that time, so that the costs of the extensions are not shared by other assets, necessarily goes hand in hand with isolation from the K factor calculation. In the light of it being technically reasonable, the Commission considers that new extensions which enter the RAB under the economic feasibility test should be isolated from the K factor calculation. Further, at the scheduled reviews, their tariffs should be calculated in such a way that they fully recover the costs associated with the assets (that is, their tariffs should not be derived from the general cost allocation methodology as described in chapter 8 of this Final Decision). To do otherwise would be contrary to the interests of users and prospective users (section 2.24(f)). This decision means that these assets will need to recover their costs from their own tariffs. This still allows GasNet to earn a revenue stream that recovers efficient costs (section 8.1(a)). The Commission notes that GasNet's current cost allocation model already isolates the Southwest Pipeline and the relevant part of the Interconnect Assets.

The extensions applicable to this decision are the Murray Valley Pipeline and the portion of the Southwest Pipeline which the Commission has decided to incorporate into the RAB under the economic feasibility test. The Commission has considered whether the WTS should also be quarantined. It does not consider this appropriate as the WTS is already in GasNet's RAB and it is not being included through the economic feasibility test. Its benchmark revenues were calculated in conjunction with those of the PTS in the 1998 Final Decision.

The Commission considers that removal of the injection tariff on the Southwest Pipeline, and related peak volume from the K factor calculation is desirable for the reasons discussed earlier. Annual volumes transported by the Southwest Pipeline and subject to withdrawal tariffs should remain in the K factor calculation as these tariffs relate to recovery of costs associated with withdrawal tariffs.

The purpose of the K factor calculation (which ensures the recovery of forecast average revenue) is to isolate GasNet from the risks associated with forecasts not being realised with respect to product mix: how volumes are divided between Tariff V and Tariff D customers; how volumes are divided between zones; and the relationship of peak to annual volumes.

Simply removing the Southwest Pipeline tariff and peak volumes from the K factor calculation would expose GasNet to risks associated with forecasting the source of gas demanded on the PTS. For example, if users decide to source more gas from Longford and less from Port Campbell, GasNet would lose revenue from the Southwest Pipeline but the K factor will remove the extra revenue GasNet gains from the extra transportation on the Longford injection pipeline. The Commission does not consider this appropriate. It is important to note that if there were no K factor calculation, there would be no reason to require a mechanism that would remove revenue earned on the Longford pipeline to the extent it was deemed that any of its volume was originally earmarked for transportation on the Southwest Pipeline. Consequently, the Commission considers simply removing the Southwest Pipeline from the K factor calculation would inappropriately expose GasNet to increased risk.

An alternative adjustment to the K factor mechanism would be to remove all injection pipelines from the tariff calculations. This would remove the risk associated with apportioning demand over the injection zones but would expose GasNet to the risks associated with the relationship between peak and anytime volumes.[378]

The Commission considers that the K factor mechanism can be amended so that GasNet does not unnecessarily face increased risk (associated either with forecasts of zonal volumes or peak volumes in relation to annual volumes). This is achieved by deeming forecast and actual peak Southwest Pipeline volumes to be, for the purposes of the K factor calculation, volumes associated with Longford.[379] In this case, a shift by users to source from Longford instead of the Southwest Pipeline will not alter the K factor calculations at all (assuming total demand remains unchanged). The K factor calculation will be indifferent to whether gas is sourced from Longford or the Southwest Pipeline. The actual revenue received by GasNet would be affected, but the K factor calculation would not require a further adjustment. Only revenue from Southwest Pipeline tariffs would contribute to Southwest Pipeline costs.

The Commission has discussed this option with GasNet which, based on a brief assessment, has indicated agreement. If further analysis by GasNet is able to clearly demonstrate to the Commission that this approach is flawed then the Commission proposes that the K factor mechanism be amended by removing all injection pipelines. GasNet has indicated in discussions with the Commission that it prefers the removal of all injection pipelines (with the associated peak to annual volume risk) rather than the removal of just the Southwest Pipeline (with the associated injection zone risk). The Commission is prepared to implement GasNet's option as it considers it appropriate to implement the adjustment which increases risk the least and it considers GasNet is better placed than the Commission to make that assessment.

Amendment 23

GasNet must revise the calculation of the K factor adjustment so that peak volumes (forecast and actual) associated with the Southwest Pipeline are deemed to be associated with the Longford injection pipeline. If this revision is demonstrated to be impractical, GasNet must remove all injection pipelines from the K factor mechanism.

GasNet has proposed two parts to the tariffs applicable to users located on the Murray Valley Pipeline: one part recovers the costs associated with the Murray Valley Pipeline extension and the other part recovers a fair share of costs (calculated using GasNet's standard cost allocation model) associated with transportation of gas on the withdrawal pipes to the beginning of the Murray Valley Pipeline (at Chiltern Valley). Removal of the Murray Valley Pipeline from the K factor mechanism is effectively accomplished by removing only the first part of the tariffs as this is the component associated with recovery of Murray Valley Pipeline costs. If volumes vary from those forecast on the

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378 Currently, for example, if peak volumes were less than forecast but annual volumes were the same as forecast, the average revenue would fall. The K factor would then increase tariffs in the following year to recover the average revenue shortfall. GasNet's revenue recovery would be the same as if forecasts had been achieved. If all injection pipes were removed from the K factor calculation then in the above scenario there would be no adjustment as there would be no change to the average revenue calculated by the K factor (although there would be a reduction in average and total revenue experienced by GasNet). Thus GasNet would be exposed to the risk of forecast peak volumes differing from actual peak volumes.

379 These volumes will therefore have the Longford tariffs applied to them in the K factor calculation.

Murray Valley Pipeline, the K factor calculation will then ensure that the average costs of the system (other than Murray Valley Pipeline and Southwest Pipeline) are recovered. However, revenues associated with the cost of the Murray Valley Pipeline itself will be totally determined by the volumes of user demand.

Amendment 24

GasNet must revise the calculation of the K factor adjustment so that, for the annual volumes (forecast and actual) associated with the Murray Valley Pipeline, the applicable tariff is not the complete Murray Valley tariff but the portion covering system costs of transportation to Chiltern Valley.

In section 3 of this Final Decision the Commission requires GasNet to amend the K factor adjustment mechanism in Schedule 4 of the access arrangement to incorporate any positive or negative pass through amounts that may occur in a regulatory year. As a consequence, if a pass through event occurs and is approved by the Commission, then the K factor mechanism will not only adjust for the under (over) recovery of average revenues, but will also include any relevant pass through amounts. The collection of these adjustments into one mechanism means that users will only face one tariff change per year.

6.2.3 Efficiency carryover

In its submission to the Draft Decision, GasNet proposed an allowance of approximately $2.3 million (NPV terms) in the second access arrangement period for first period efficiency gains. While the Commission acknowledges GasNet’s assertion that much of its first period efficiency gains were not sustainable, a comparison of historical data for that period against second period forecasts suggests that GasNet achieved substantial efficiency gains that should in principle be shared with users in the second period. The Commission considers that because of the uncertainty relating to the benefit sharing mechanism that GasNet was subject to at the start of the initial access arrangement period, it may be unreasonable to penalise GasNet in the second period for efficiency losses. Accordingly, the Commission considers that an efficiency carryover of zero in the second period for first period behaviour would be appropriate. This approach is discussed in detail in section 10.1.7 of this Final Decision.

6.2.4 Asymmetric risk

In its initial submission to the Commission, GasNet identified a number of specific risks that it considered to be asymmetric and should be recoverable through an allowance in the cash flows. GasNet considered these risks have the features of:

- asymmetry, that is the possible negative outcome of the event is greater than the possible positive outcome;
- insurance being difficult, if not impossible, to obtain at a commercial rate;
- investors being unable to diversify away the risk; and

- GasNet's likely economic income would be less than the target economic income because of these risks.[380]

The asymmetric risks identified by GasNet are shown in Table 6.12 below. These amounts increase with inflation over the period. Many of the annual allowances included in this table reflect an estimate of self insurance by Trowbridge Consulting.[381]

Table 6.12: Proposed asymmetric risk allowance, 2003

Risk	Allowance ($)
Property related risks	20 000
Deductibles in current insurance	140 000
Credit risk	252 000
Terrorist threat	65 000
Risk of stranding	75 000
Other	200 000
Total	752 000

Source: GasNet access arrangement information, 27 March 2002, p. 11.

BHP Billiton expressed concern that the Trowbridge Consulting report is confidential when it is likely to 'provide important information on such a significant issue'. BHP Billiton claimed that as GasNet proposed to undertake self insurance, the funds should be placed in a trust fund and not in general revenue.[382] In response, GasNet stated:

> BHP Billiton's appears to suggest that the self-insurance costs should be treated as a form of indemnity fund rather than as a risk-weighted cash flow amount. GasNet considers that BHP's suggestion is an unwarranted interference in GasNet's management prerogatives.[383]

The Commission has agreed to GasNet's request for the Trowbridge Consulting report to remain confidential. Publication of the report may prejudice GasNet's dealings with insurance companies as it details the value of, and need for, various types of insurance.

As noted in its recent Draft Greenfields Guide, the Commission considers that the regulatory framework can address asymmetric risk (whether upside or downside) for transmission pipelines. In addition, the Commission notes that specific risks need to be assessed separately for each access arrangement and factored into the business' cash flows rather than the cost of capital.[384]

In general, the Commission considers that:

> ... to adequately assess a proposal for self-insurance, in relation to prudency and validation of an appropriate premium, it would need to consider such matters as: a report from an

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380 GasNet submission, 27 March 2002, schedule 4, pp. 28-29.

381 The Trowbridge Consulting report to GasNet has been provided to the Commission (as annexure 7 of GasNet's submission) on a confidential basis.

382 BHP Billiton submission, 21 June 2002, p. 23.

383 GasNet response to submissions, 24 July 2002, p. 12.

384 ACCC, *Draft greenfields guideline for natural gas transmission pipelines*, June 2002, pp. 12-13.

appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums; confirmation of the board resolution to self-insure; and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for.

A regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring. In the event of future expenditure required as a result of an insurance event such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operations and maintenance element of the allowed tariffs and funded by users.[385]

While GasNet has proposed to include an asymmetric risk allowance in the cash flow, it has not provided explicit confirmation that the business will self-insure for certain identified risks and that future actual costs relating to these events will not be included in future regulatory cash flows. The Commission generally requires that this assurance be provided by a resolution from the company's board of directors. However, in light of the amount of asymmetric risk allowance the Commission accepts for GasNet, the Commission will accept confirmation from the company in this instance. A resolution from the board would be required for a larger amount. The Commission considers that if GasNet is not prepared to provide this confirmation then it should not include any asymmetric risk allowance in its cash flows. An amendment to the proposed revised access arrangement is required.

Amendment 25

GasNet must include in clause 4, reference tariff policy, of its revised access arrangement:

- explicit confirmation that the business will self-insure;
- details that clearly specify the self-insured risks consistent with this Final Decision; and
- explicit confirmation that future actual costs relating to these identified events will not be included in future regulatory cash flows.

If GasNet does not accept these inclusions in clause 4, then GasNet must remove all allowances for asymmetric risk from its revenue calculations.

Property related risks

GasNet includes pipeline corrosion risk as part of its property related risks, which it states is excluded from its existing property insurance. It also includes bomb threat risks. Insurance policies of this nature generally cover losses due to payment of a ransom, other related expenses and loss of earnings.

The Commission would expect that the risk of pipeline corrosion is largely with GasNet and could be considered to be controllable. Inadequate levels of pipeline maintenance may lead to a greater likelihood of corrosion. GasNet is the party in the best position to determine the level of appropriate maintenance, the likelihood of pipeline corrosion and the financial consequences of its decision. Accordingly, the

385 ibid., p. 16.

Commission concludes that allowances related to pipeline corrosion should not be accepted.

The Commission understands that the remaining items included in this category are insurable but that GasNet does not hold insurance for them at this time. In effect, GasNet is proposing to self-insure for these events.

In its Draft Decision the Commission proposed to accept an amount of $10 000 per year for property related risks. No further information, from GasNet or interested parties, was received subsequent to the Draft Decision. Accordingly, the Commission affirms its Draft Decision and accepts the proposed cash flow of $10 000 per year.

Deductibles in current insurance

Deductibles in current insurance reflect action on the part of GasNet to limit its insurance costs. This category includes the payment of an excess when a claim is made and the payment of claims above the insured amount. The corollary is a reduction in the amount paid in premiums to insurers which may be a prudent business practice to undertake.

The Commission understands that GasNet is required to maintain insurance for certain events pursuant to the SEA. The deductibles relevant for the various policies vary considerably.[386]

The Commission's Draft Decision acknowledged that these considerations can constitute a legitimate expense. However, as with insurance premia, they are difficult to predict with accuracy. Consequently, the Draft Decision included a proposed amendment to include the actual expenditure of deductibles in the calculation of the insurance pass through event. The Commission has not received any comments on this proposal from interested parties. GasNet has accepted the Commission's proposed amendment.[387]

As noted in the Draft Decision, the uncertainty for GasNet as to whether the estimated allowance is sufficient is removed by the use of pass through and this is in the interest of GasNet pursuant to section 2.24(a) of the Code. It is also in the interest of users (section 2.24(f)) to pay tariffs that cover costs incurred rather than a possible overestimated allowance. An amendment in section 3.2 of this Final Decision requires GasNet to include the deductibles for its current insurance policies in the pass though mechanism.

Credit risk

The proposed allowance for credit risk reflects a risk of insurers and counter parties defaulting. First, in respect of insurers' credit risk, GasNet is seeking to self-insure the loss of premium paid relating to the unexpired period of cover upon an insurer being unable to honour an insurance policy (due to, for example, bankruptcy). Trowbridge Consulting has estimated an annual premium for this type of event. The Commission concluded in its Draft Decision that an allowance in GasNet's cash flows is not

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[386] GasNet response to Commission, 23 July 2002.

[387] GasNet submission, 20 September 2002, p. 27.

unreasonable. Interested parties have not provided any comment on the proposal. The Commission has decided to accept the proposed cash flow relating to insurers' credit risk.

The second component of the credit risk allowance relates to counter party credit risk, that is, the risk that the Victorian gas retailers and other users of the transmission system fail to pay GasNet amounts owing in relation to regulated transmission charges. GasNet has based the proposed allowance on a quotation for an insurance policy. Similar amounts were also proposed by the gas distribution businesses which the ESC assessed in some detail. The ESC determined that the expected revenue losses arising from counter party bankruptcy were overstated in light of the terms and conditions relating to the distributors' reference services; the average default rate of BBB rated firms and the recovery rate of debt; and the credit ratings of the firms in question. It concluded that 'the expected loss associated by retailer default would be close to $10 000'.[388]

In its Draft Decision the Commission considered that the adjustments made to the counter party credit risk claims by the ESC were also relevant to GasNet's proposals. In addition, it noted that the revenues subject to this risk are greater for the distribution businesses than GasNet and a proportional adjustment to the annual allowance proposed by GasNet could be made. However, on balance, the Commission proposed to accept an annual allowance of $10 000 for GasNet's counter party credit risk**.**

GasNet does not agree with this proposal, suggesting that there are significant differences between the distributors and itself. It notes that the Gas Transportation Deeds 'do not impose any creditworthiness restrictions on the users' and that

> ... although the MSO Rules do impose certain prudential requirements on these potential users, they do not protect a gas transmission company from defaulting users. Therefore, GasNet is uniquely exposed to customer default.[389]

GasNet also suggests that some of its transmission customers in the future may have a greater default risk than the current retailers. GasNet concludes its comments proposing that:

> If the Commission rejects a reasonable self-insurance premium for credit risk, then GasNet considers that it would be appropriate to include this risk in the pass through mechanism contained in GasNet's draft Access Arrangement.[390]

The Commission did not receive any comments from interested parties on this matter subsequent to the Draft Decision.

The Commission has considered GasNet's claim that it is particularly exposed to the risk of defaulting customers. However, the claim is not supported by any substantive information. The Commission understands that the MSOR prudential requirements apply to all market participants. However, GasNet has not expanded on its assertion,

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388 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 275.

389 GasNet submission, 20 September 2002, p. 28.

390 ibid.

which has been noted above, or clarified why these requirements do not impact on GasNet's users.

At present users of the PTS include retailers and a significant industrial customer. GasNet's submission implies that non-retailer users of the PTS may have a greater default risk than retailers and notes that 'the recent collapse of Enron is evidence that a real risk of default by a trader exists'.[391] However, the Commission considers that it would be equally possible that non-retailer users will have credit ratings at least as high as the current retailers and have a minimal default risk. In addition, the Commission expects that while non-retailer users may have substantial demand for gas, the retailers would remain the predominant users of the PTS. This would limit the impact of any defaulting non-retailer user on GasNet's total revenues. Without any new users of the PTS the Commission is unable to gauge the accuracy of GasNet's assertion that its risk will be significantly higher to justify an annual allowance of $250 000.

It does not appear to be in the interest of users (pursuant to section 2.24(f) of the Code) or indicate the efficient operation of the pipeline (section 2.24(d)) to include an allowance for defaulting customers that as yet do not exist.

GasNet proposed a pass through mechanism as an alternative to an annual allowance. However, GasNet has not identified the particular events that would be included in the pass through mechanism. In addition, the Commission is not satisfied that GasNet's assessment of the scope of its perceived risk is appropriate and accordingly, the impact of a possible pass through event on users is unclear. This uncertainty suggests that it is not in the interest of users (pursuant to section 2.24(f) of the Code) to accept a pass through mechanism for credit risk.

Consequently, without further evidence supporting the claim, the Commission concludes that its proposed allowance of $10 000 per year remains appropriate for this Final Decision.

Terrorist threat

In its March 2002 submission to the Commission GasNet stated that terrorist sabotage cannot be insured against and commented that US utilities have been threatened recently. While Trowbridge Consulting did not quantify this risk, GasNet estimated a premium of $65 000 based on a value of aboveground assets of $140 million and a one in five hundred event.

In its Draft Decision the Commission commented that it would appear that the likelihood of terrorist sabotage for GasNet would be very small. The indication from Trowbridge Consulting is that estimates of an insurance premium would vary significantly and be subjective. Without the ability to ensure that the proposed cost is prudent the Commission stated that it was inclined not to include this cost in the calculation of reference tariffs. It also noted that it did not regard GasNet's likelihood of becoming subject to this event as being different to other Australian businesses as a whole and that to the extent that all Australian businesses face a terrorist threat, the market will accommodate the related risk. Accordingly, the Commission's Draft

[391] ibid.

Decision proposed to exclude the $65 000 annual allowance from GasNet's proposed costs.

GasNet does not agree with this conclusion. It suggests that as insurance companies now refuse to cover terrorist sabotage they do not regard the risk as small or immaterial and that 'the fact that the risk is difficult to quantify does not mean that the prudent premium is zero'. GasNet also considers that the risk is not diversified to zero (nor does it become a non-diversifiable risk) because the whole market faces the risk. It suggests that 'so long as this specific risk is present, the value of GasNet's business will be reduced and accordingly, a cashflow adjustment will be required'.[392]

GasNet requests that if a self-insurance cash flow is not accepted by the Commission then the event be included in the pass through mechanism. It notes that this may result in a very significant tariff jump for users.

The Commission did not receive any other comments relating to this topic.

The Commission has considered GasNet's calculation of the annual allowance for terrorist threats. The allowance is based on a value of aboveground assets of $140 million and damage to a single asset of $25 million. The Commission understands that the most significant regulated aboveground assets would be the compressors.[393] The data in the model used to calculates revenues for GasNet show a total value for the five compressors to be approximately $42 million. It would appear that the calculation of an allowance for terrorist risk is not consistent with GasNet's own revenue model.

In the event that a terrorist action does cause damage to some part of the PTS the Commission would expect the written down regulatory value of the asset at that time to be depreciated, providing GasNet with a return of capital. Any capital expenditure then required to rebuild the asset could be added to the capital base through section 8.16 of the Code. An application to revise the access arrangement for these events can be made by GasNet at any time. This course of action negates the need to include terrorist threats in the pass through mechanism.

As discussed in the Draft Decision, the Commission would be hesitant to include an annual allowance when it is unable to confirm that the proposed cost is prudent. The observation that the proposed allowance appears to be inconsistent with the revenue model increases this concern. It is not appropriate for tariffs to be calculated on the basis of costs that are not prudent. Consequently, the Commission is not satisfied that the proposed annual allowance would be in the interest of users (pursuant to section 2.24(f) of the Code). Nor would it reflect the economically efficient operation of the pipeline (section 2.24(d)).

As outlined above, the access arrangement and the Code establish a process to incorporate new capital expenditure and manage 'redundant' assets. The Commission considers that it would be in the interests of users (section 2.24(f)) to make use of these provisions rather than include an allowance in the cash flows or implement a pass

392 ibid., p. 29.

393 While significant, the LNG facility is not a regulated asset under the PTS access arrangement.

through mechanism. In the Commission's view, the provisions are not contrary to GasNet's business interests (pursuant to section 2.24(a)).

Accordingly, on balance the Commission is not satisfied that the proposed annual allowance of $65 000 is appropriate. Nor does it consider that a pass through mechanism is required for this event.

Risk of stranding

GasNet considers that its laterals are subject to the risk of bypass, or stranding. As an example, it notes that the proposed Iona to Adelaide pipeline would pass towns currently supplied by the WTS. In this case, GasNet has proposed a prudent discount for these users. In addition, GasNet suggests that the current redundant capital policy would cause partial and wholly redundant assets to be removed from its regulatory capital base. Based on a one per cent probability of five per cent of laterals being bypassed, GasNet has estimated a self insurance premium of $75 000 per year.

In assessing any redundant capital policy the Commission is required, pursuant to section 8.27 of the Code, to 'take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have'. The Commission considered this factor when it assessed the access arrangement for GasNet's predecessor in 1998. It has also been included in its current assessment of the redundant capital policy. Accordingly, it is not appropriate to make any further adjustment, whether to CAPM or the cash flows, for this policy.

GasNet has referred to the possible bypass of part of the WTS. As noted above, GasNet has proposed a prudent discount for the relevant WTS users. The Commission considers this course of action is appropriate for a potential bypass event. As noted in the *Draft Statement of Principles for the Regulation of Transmission Revenues* (DRP), the Commission generally considers an adjustment of the asset's depreciation schedule (that is, an acceleration of the depreciation allowance) is also an appropriate response.[394] Accordingly, any additional adjustment to the cash flows, as proposed by GasNet, does not appear necessary or appropriate. In general, the Commission does not consider the risk of stranded assets is significant for GasNet. Even if this were the case, the Commission would expect GasNet to make use of its ability to offer prudent discounts and the flexibility of its depreciation schedules. Consequently, the Commission's Draft Decision proposed to exclude the additional $75 000 per year from GasNet's cash flows.

No further comments on this matter have been received by the Commission. The Commission confirms its Draft Decision that the proposed cash flow is not appropriate and is not to be included in GasNet's calculation of revenues.

Other risks

GasNet notes that a number of other asymmetric risks have been identified by Trowbridge Consulting totalling $200 000 per year. No further information was available to interested parties.[395] The Commission accepted GasNet's confidentiality

[394] ACCC, DRP, May 1999, p. 62.

[395] GasNet submission, 27 March 2002, schedule 4, p. 32.

claims. Consequently, the Commission's assessment in the Draft Decision was expressed in general terms.

GasNet is liable for uplift payments to other market participants if it fails to meet its obligations under the SEA. The liability is limited to the lower of $20/GJ or $1 million per year. Under GasNet's proposal, the risks attached to this allowance would be shifted from GasNet to users. GasNet's reference tariffs are based on the costs associated with maintaining the PTS to the level required under the SEA. In effect, users would be paying twice to have the PTS operate as specified by the SEA. This would be an unsatisfactory situation. Accordingly, the Draft Decision proposed to exclude the proposed cost.

In response to the Draft Decision GasNet asserted that if equipment fails and exposes the business to uplift penalties it will result in its return to equity falling below 'the fair and reasonable target level'.[396] GasNet acknowledged that while the cost of equipment failure would be minimised by a skilled and prudent operator, random failures will occur. GasNet suggests that 'a prudent business would make an assessment of the appropriate level of resources to be devoted to equipment maintenance' and that 'it is prudent to make some provision for the costs of equipment failure in the cashflows'.[397]

GasNet states that it has considered the cost of failures further since its initial proposal. It identifies additional costs relating to rehabilitating and replacing failed equipment above the budgeted operating costs. Consequently, GasNet now considers that a cash flow item of between $65 000 and $100 000 per year would be appropriate for the risk of uplift.

The Commission acknowledges that some risk of equipment failure would exist for a prudent service provider regardless of whether the pipeline operates under market or contract carriage. It expects that an allowance for this event would be included in the operations and maintenance expenditure of the business. The information available to the Commission does not identify an allowance for equipment failure as an exclusion from costs for pipelines that have been used as benchmarks for GasNet. Similarly, the item has not been identified as an exclusion from the forecast operations and maintenance costs for GasNet for 1998 to 2002. The Commission approved the operations and maintenance costs for the first access arrangement period with the understanding that they represented total costs for the regulated business. The Commission also notes that the approved current forecast operations and maintenance costs include expenditure to fix some compressor equipment that is subject to 'random failure' (see section 6.1.7 of this Final Decision).

Consequently, the Commission concludes that GasNet's reference tariffs include some allowance for this event. It also concludes that the cost is included in the total costs of benchmark pipeline businesses. As stated in the Draft Decision, the Commission does not consider that it is in the interest of users (see section 2.24(f) of the Code) to pay for this event twice. Nor would the inclusion of the proposed allowance reflect the economically efficient operation of the pipeline (in regard to section 2.24(d)).

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396 GasNet submission, 20 September 2002, p. 29.

397 ibid.

Accordingly, the Commission does not accept the proposed annual allowance of $65 000 to $100 000.

GasNet proposed an allowance for partially stranded assets. The impact of stranded assets on GasNet is illustrated by unforecast supply from Yolla. The appropriate regulatory approach to stranded assets (in part or in total) has been noted above in relation to the WTS. That is, in general the appropriate approaches are to utilise the prudent discount provisions of the Code or accelerate the asset's depreciation allowance. Once an asset has become stranded the redundant capital policy may be used to remove the asset from the capital base. Consequently, the Commission's Draft Decision did not accept an allowance for the possibility of the partial stranding of assets.

GasNet's concern with regard to the potential impact of the development of the Yolla fields in particular was noted in the Draft Decision. The Commission referred to its proposal to include related flows in the demand forecasts for the second access arrangement period.

No further comments from interested parties or GasNet were received in relation to the Commission's decision on an allowance for partially stranded assets.

Yolla gas may displace a small proportion of the total flow from Longford.[398] Consequently, an appropriate response to this situation may be to accelerate the depreciation allowance for the Longford pipeline. This course of action was proposed by GasNet although it was not accepted in the Commission's Draft Decision. However, this Final Decision accepts the proposed acceleration of the Longford pipeline depreciation allowance.

The Commission remains of the view that an allowance for the possible partial stranding of assets is not an appropriate inclusion in the cash flows for GasNet.

GasNet also proposed an allowance for key person risk. Insurance policies are available in relation to the risk of business disruption costs arising from the sudden departure of key staff and the cost of finding a suitable replacement. The ESC considered self insurance for the loss and replacement of key staff of the gas distribution businesses. It stated it 'would find it difficult to accept that there would be any significant disruption to earnings – revenue would continue to flow, and procedures for maintaining assets would continue to be followed regardless'.[399]

The Commission's Draft Decision agreed with the ESC's view and noted that the only clear activity that may suffer disruption would be market development, a relatively minor aspect of a transmission company's business. It also noted that GasNet was without a Chief Financial Officer for a considerable period and had only recently filled the position. The Commission was not aware of any disruption to GasNet's business operations as a result of this vacancy. In addition, the Commission noted that it did not

398 The main impact of Yolla gas for the purposes of the current review is that forecast flows originating from the Otway basin are reduced.

399 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 276.

consider that GasNet is alone in facing the possibility that key staff may leave the business, it would be a 'risk' faced by all businesses.

The Draft Decision concluded that the Commission did not consider that the claimed self insurance cost was appropriate and the proposed annual cost of key person risk was to be excluded from GasNet's cash flows.

While no interested party commented on this conclusion, GasNet asserted that the estimate of $72 000 per year from Trowbridge Consulting remains appropriate. The $72 000 includes additional replacement costs of $17 600 and business disruption costs of $54 000.

GasNet agrees that there would be little likelihood that income from tariffed services would suffer on the loss of a key person within the organisation. However, GasNet does consider that consultants and contracted staff would be required to undertake the duties of the key person and that this would require additional supervision and management from existing personnel.[400]

An additional self insurance item relates to wrongful acts in relation to employment practices. This includes sums for damages, settlements and other costs relating to actions of harassment, unlawful discrimination and breaches of privacy. The Commission noted in its Draft Decision that it does not consider that this event is specific to GasNet. All businesses must comply with the relevant legislation on these matters. The Commission concluded in the Draft Decision that it did not consider it appropriate to provide an allowance to GasNet to self-insure for this event and the proposed amount was to be excluded from GasNet's cash flows.

In response, GasNet acknowledges that other businesses face this risk. However, it has reiterated its view that it should be compensated in the cash flows for wrongful acts in employment practices.

With respect to both these costs the Commission notes that all businesses would face the possibility of these events occurring. Accordingly, the Commission would expect that the operations and maintenance benchmark data from other pipelines would have been determined after considering the risk of these events. Similarly, the Commission has no reason to expect that the approved costs for GasNet for 1998 to 2002 excluded these events. That is, the Commission concludes that the total operations and maintenance costs of GasNet, for the period 1998 to 2002, and other pipeline businesses includes any costs that may arise from the employment related events.

In effect, it appears that GasNet is seeking to charge users twice for the possibility that these events may occur. The Commission does not consider that this is in the interest of users (pursuant to section 2.24(f)) or that it represents the efficient operation of the pipeline (section 2.24(d)).

In regard to key persons, the Commission would expect that a prudent business would ensure that the skills base of its staff is sufficiently broad to accommodate some unexpected staff movements. The Commission notes that it has accepted proposed

400 GasNet submission, 20 September 2002, p. 30.

costs for GasNet to increase its staff skill base and undertake recruitment during the forthcoming access arrangement period.[401] In addition, the Commission would anticipate some savings for a business upon the departure of a key person (for example, as experienced by GasNet during the initial access arrangement period). This would offset at least some of the additional costs incurred. Consequently, the Commission is not satisfied that the proposed allowance of $72 000 per year represents the best estimate of forecast costs.

Furthermore, with respect to a specific allowance for wrongful employment acts, the Commission does not consider it to be in the public interest (pursuant to section 2.24(e) of the Code) to compensate a business for breaches of the law.

Accordingly, the Commission does not consider that the proposed annual allowances for key persons (of $72 000) or wrongful employment practices (of $35 000) are appropriate and does not accept their inclusion in GasNet's forecast costs.

Conclusion

The Commission's Draft Decision noted that, in principle, it would be appropriate for costs associated with asymmetric risks to be included in the calculation of GasNet's cash flows when determining benchmark revenue. However, it concluded that a number of GasNet's claims were unjustified and that an appropriate allowance would be $22 000 a year in total.

As a result of further assessment of the proposals from GasNet, as well as the additional information provided, the Commission has decided to accept a total annual allowance of $22 000 for property related and credit risks. The proposed allowances for the other asymmetric events are not appropriate and are to be excluded from the calculation of GasNet's revenues for 2003 to 2007.

Amendment 26

GasNet must amend clause 3.5 of its revised access arrangement information so that the total annual allowance for asymmetric risks is $22 000 (in 2003 dollars) for each year of the access arrangement period.

6.2.5 Working capital

In the first access arrangement period, tariffs were based on benchmark revenue which included a return on working capital. This item consisted of the net of debtors and creditors, linepack and spare parts inventory. Since the 1998 Final Decision, the Commission has indicated in other decisions that it does not think that a return on the net of debtors and creditors is necessary as the simplifying assumptions of the revenue modelling more than compensate for the absence of this refinement.[402] GasNet has not proposed a return on the net of debtors and creditors for the second access arrangement period.

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[401] See GasNet submission, 27 March 2002, p. 83.

[402] See, for example, ACCC, *Final Decision: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, pp. 29-30.

However, GasNet does propose that a return be included in the cash flow calculations for the cost of maintaining linepack and inventories (which together it labels as working capital). GasNet is claiming $0.3 million a year as the result of applying the nominal WACC to its investment in these two items.[403]

The Commission would normally consider inventory of spare parts and linepack to be assets which form part of the capital base of the firm. It notes that the GHD valuation in 1997 included values for each of these items. As such, a return on these items is appropriate. As a return on these items was included for the first access arrangement period as working capital, and they were not included in the ICB, the Commission is unable (for reasons discussed in section 4.1 of this Final Decision) to include them in the RAB now. Consequently, the Commission considers it appropriate to continue to provide for the cost of funding these items through a 'working capital' item to be added to the revenue calculations.

While in its submission GasNet suggested the appropriate return is the nominal WACC,[404] the Commission considers the vanilla WACC to be appropriate. Whether a nominal or real (vanilla) WACC is appropriate will depend on whether the linepack and spare parts are valued at nominal or real cost.

The Commission has some concern with the valuations proposed by GasNet and has indicated to it the methodology the Commission considers appropriate. For example, the Commission considers it inappropriate for GasNet to claim a return on spare parts for the LNG facility (which is not part of the RAB and whose services are not regulated) or to claim a nominal return on items with a real valuation. In addition, it would be inappropriate for items to be valued at replacement cost rather than what GasNet actually paid. The appropriate amendments will produce a lower amount than that claimed by GasNet ($0.1 million rather than $0.3 million). Accordingly, and amendment to the access arrangement information is required.

Amendment 27

GasNet must amend clause 3.5 of its access arrangement information so that in calculating a return on linepack and spare parts, GasNet must base the valuation of the items on historical expenditure and must use a valuation approach (nominal or real) consistent with the vanilla WACC to be applied. The value of spare parts not associated with regulated services must be removed from the calculations.

6.3 Capital expenditure

6.3.1 Code requirements

Pursuant to section 8.20 of the Code, reference tariffs may be determined based on forecast new facilities investment for the forthcoming access arrangement period if it is

403 GasNet access arrangement information, 27 March 2002, pp. 9-10.

404 GasNet submission, 27 March 2002, p. 91.

reasonably expected to pass the requirements of section 8.16 of the Code when the investment is forecast to occur.

If the regulator agrees to this approach, the Code (section 8.21) states that this need not imply that the new facilities investment in question will meet the requirements of section 8.16 when the relevant revision to the access arrangement is assessed. However, in determining that reference tariffs may be calculated on the basis of forecast capital expenditure, the regulator may make a binding decision that the forecast new facilities investment will satisfy the Code's requirements and be included in the capital base through a future revisions application. Any application seeking such a decision from the regulator must be treated as if it was an application to revise the access arrangement in accordance with section 2.28 of the Code.

In addition, section 8.22 of the Code requires the reference tariff policy to state, or the regulator to require, how new facilities investment is to be determined when establishing the capital base for a new access arrangement period in accordance with section 8.9 of the Code. This includes whether (and how) the capital base is to be adjusted when actual new facilities investment differs from forecast new facilities investment.

6.3.2 Current access arrangement provisions

GasNet's current policy relating to new facilities investment is set out in clause 5.3.3 of both the PTS and WTS access arrangements. It states that GasNet's extensions and expansions policies (see section 11.3 of this Draft Decision) explain how new facilities investment will affect reference tariffs.

The access arrangement information for the PTS and the WTS identifies a number of capital projects that were forecast to occur within the initial access arrangement period. A total of $56.3 million was forecast.[405] The most significant item was the Brooklyn loop with a forecast cost of $27.15 million.[406] Other projects included compressor automation and general maintenance capital expenditure.

These projects were included in the calculation of revenues and reference tariffs for 1998-2002 on the basis that they were likely to satisfy the requirements of section 8.16 of the Code. However, the Commission did not determine whether the section 8.16 criteria were satisfied at that time. This assessment was expected to occur either at the time the investments took place or after the expenditure had been undertaken when the actual expenditure was known.

The assessment, pursuant to section 8.16 of the Code, of actual capital expenditure for the initial access arrangement period is provided in section 4.2 of this Final Decision.

6.3.3 GasNet proposal

GasNet states that its proposed reference tariffs have been calculated on the basis of forecast capital expenditure that is, in its view, reasonably expected to pass the

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405 TPA access arrangement information, 30 November 1998, p. 13.

406 GasNet submission, 27 March 2002, p. 38.

requirements of section 8.16 of the Code. GasNet notes that it may submit revisions to the access arrangement within the anticipated access arrangement period in relation to other new facilities investments that satisfy the requirements of section 8.16 of the Code.

As permitted by section 8.18 of the Code, GasNet states in its proposed reference tariff policy that it may also carry out new facilities investment that does not meet the requirements of section 8.16 of the Code. If 'speculative investments' are undertaken by GasNet then, as outlined in the Code, the recoverable portion may be added to the capital base and the balance included in a speculative investment fund for possible future inclusion into the capital base.[407]

GasNet has proposed a number of capital projects totalling $87.04 million for the forthcoming access arrangement period. These are outlined in the table below.

Table 6.13 Proposed forecast capital expenditure, 2003 to 2007

	$ million[a]					
	2003	**2004**	**2005**	**2006**	**2007**	**Total**
Brooklyn loop					20.70	20.70
Gooding compressor			6.49	8.13	7.95	22.57
Lurgi pipeline	2.05	2.10	1.55	5.83	5.97	17.50
City gates		2.36	2.53	4.41		9.30
Wollert compressor		1.50	1.82			3.32
Service lines	1.54	1.58	1.62	1.66	1.70	8.10
Maintenance	1.90	1.43	0.51	0.59	1.12	5.55
Total	5.49	8.97	14.52	20.62	37.44	87.04

Source: GasNet access arrangement information, 27 March 2002, p. 12.
Note: (a) All in nominal dollars for years ending 30 June.

6.3.4 Submissions to Issues Paper

The Commission received a number of broad comments in regard to the forecast capital expenditure for the forthcoming access arrangement period. ENERGEX expressed concern about the overall size of the forecast capital expenditure and raised the possibility of the gold plating of assets.[408] BHP Billiton considered that no quantitative analysis had been provided by GasNet to support the forecast capital expenditure. It stated that while users expect the pipeline system to be improved, GasNet had not provided any cost-benefit analysis in regard to the resources that it expects to employ.[409] Similarly, TXU considered that GasNet had not provided enough information to allow any detailed comment but it did suggest that VENCorp could comment on the proposal's consistency with its annual planning review.[410] In contrast, Origin accepted

407 GasNet access arrangement, 27 March 2002, pp. 5-6.
408 ENERGEX submission, 9 May 2002, p. 4.
409 BHP Billiton submission, 17 May 2002, p. 13.
410 TXU submission, 31 May 2002, p. 31.

that 'the proposed forecast capital expenditure is consistent with reasonable and prudent practice'.[411]

More specific comments were also received. EnergyAdvice suggested that the forecast expenditure relating to the Brooklyn loop and the Gooding compressor should be allocated to peak reference tariffs. This is because, in EnergyAdvice's view, these assets would only be used in winter and accordingly, winter users of the pipeline system should pay for these facilities.[412]

6.3.5 Draft Decision

The Brooklyn loop was included in the reference tariff calculations for the first access arrangement period. At the time, TPA expected that forecast peak demand would not be satisfied by gas shipped from Longford after 2000. Accordingly, the Brooklyn loop was proposed to increase the capacity of the Brooklyn to Corio pipeline and allow gas to be supplied from the UGS facility.

On the basis that system-wide benefits may arise from the project, the forecast cost of the Brooklyn loop project was included in the reference tariff calculations for 1998 to 2002.[413] However, the Brooklyn loop project was not undertaken during the initial access arrangement period. GasNet now forecasts that it will be undertaken in 2007.

In the Draft Decision, the Commission noted that the key determinant for this project is the demand forecasts. The VENCorp demand forecasts for 2002 to 2006 do not unambiguously support augmentation of the Brooklyn loop in that period. Nonetheless, GasNet considered that augmentation was required in 2007. The Commission considered that the balance between forecast demand and available capacity was close.

The demand forecasts used by GasNet did not include any gas expected to be sourced from the Yolla field. The Commission's Draft Decision considered that flows from Yolla should be included in the forecast demand figures for the forthcoming access arrangement period. As a result, the flows on the Southwest Pipeline will differ to those proposed by GasNet and the adjusted forecast demand information will not support the need for the proposed Brooklyn loop project in 2007.

It was also noted that the inclusion of the cost of the Brooklyn loop in the forecast capital expenditure for the initial access arrangement period resulted in GasNet obtaining benchmark revenue based on a return on that forecast capital expenditure during that period. However, the Commission does not 'clawback' revenues obtained in this manner. In fact, the ability to retain the additional revenue from unused forecast capital expenditure provides an incentive for GasNet to only undertake appropriate and efficient capital projects as they are required.

The Commission's Draft Decision concluded that it was not appropriate to include forecast capital expenditure relating to the Brooklyn loop in the revised access arrangement. An amendment to the access arrangement was proposed.

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411 Origin submission, 17 May 2002, p. 6.

412 EnergyAdvice submission, 30 May 2002, p. 8.

413 ACCC, 1998 Final Decision, pp. 86-87.

The Commission's Draft Decision noted that it is likely that the Gooding compressor will need to be substantially refurbished in the near future in order to maintain the integrity and contacted capacity of services. The cost could be expected to be a substantial portion of, but not exceed that, of a new compressor station of similar size. The Commission understood that a replacement station could cost between $30 and $35 million (in 2002 dollars). The Commission's assessment was that the proposed cost of the project was not unreasonable. Consequently, the Draft Decision proposed to accept the forecast capital expenditure.

The Lurgi pipeline was constructed in 1956 and is the oldest segment of the PTS. GasNet proposed a two stage process in refurbishing the pipeline in order to maintain the safety, integrity and contacted capacity of services. First, some preliminary work and pigging would be undertaken. The work on the second stage would depend on the results of the pigging but would require the repair of minor defects at the minimum. However, partial modification of the pipeline or major enhancements could also be required in stage two.

Stage one was costed by GasNet at a total of $5.70 million over 2002-2003 to 2004-2005. On the basis of a study by the Commission's technical consultant it was of the view that these estimates were reasonable. It accepted GasNet's proposal for work to be undertaken in this area. The Commission's Draft Decision proposed to accept inclusion of the first stage of the Lurgi pipeline project in the forecast capital expenditure for 2003 to 2007.

However, the Draft Decision noted that there appeared to be considerable uncertainty regarding the most appropriate course of action for the second stage of the project. In acknowledging this uncertainty, GasNet proposed that the forecast capital expenditure in 2005-2006 and 2006-2007 should include an average of the estimated cost of the options identified (a total of $13.35 million in nominal dollars).

In view of the uncertainty surrounding the proposed work and the range of cost estimates provided by GasNet, the Commission determined that it was unable to form an opinion on whether the second stage of the project would be reasonably likely to satisfy the requirements of section 8.16 of the Code. Accordingly, an amendment was proposed in the Draft Decision to exclude any cost estimates relating to stage two of the Lurgi pipeline project in the calculation of tariffs.

It was noted that if this work does proceed, GasNet is able to seek a binding section 8.16 assessment by the Commission at that time pursuant to section 8.21 of the Code.

GasNet identified a number of city gates in the PTS which it considered require upgrading during the next access arrangement period. This upgrading would include the installation of heaters at the Dandenong, Wollert and Tyers city gates. In total $9.29 million was forecast to be spent between 2003-2004 and 2005-2006. The Commission concluded in its Draft Decision that it was satisfied that the work proposed is reasonably expected to meet the requirements of section 8.16 on the basis that it is necessary to maintain the safety, integrity or contracted capacity of services and that the forecast costs, which have been based on previous actual costs, do not appear to be unreasonable. Accordingly, the Commission proposed to accept the forecast expenditure relating to the improvement of the city gates in the calculation of the reference tariff for the revised access arrangement.

GasNet also plans to upgrade the compressor station at Wollert over two years, 2003-2004 and 2004-2005. This was expected to cost a total of $3.32 million. Minor capital expenditure of $5.56 million over the five year period was also planned. The Commission noted that this represented approximately 0.2 per cent of the ORC of the PTS and was comparable with similar expenditures for other transmission pipelines. The Commission concluded in its Draft Decision that it was satisfied that both these expenditures would be reasonably expected to meet the requirements of section 8.16 and should be included in the calculation of the reference tariff for the revised access arrangement.

GasNet's forecast capital expenditure also included $1.5 million per year (in 2002 dollars) for three possible service lines over the forthcoming access arrangement period. However, GasNet also proposed to alter the extensions and expansions policy to allow service lines to not be included automatically in its access arrangement. As discussed in section 11.3 of the Draft Decision (and in this Final Decision) the Commission proposed to accept this revision to the access arrangement. Given the uncertainty as to whether these investments would be covered by GasNet's access arrangement, the Commission decided that it was not reasonable to include the forecast expenditure for service lines in the calculation of the reference tariffs for the second access arrangement period. However, it noted that if these investments are covered by the access arrangement they may be included in GasNet's asset base (subject to the provisions of section 8.16 of the Code). Accordingly, the Commission proposed an amendment to exclude the proposed forecast capital expenditure.

6.3.6 Response to Draft Decision

The Commission has received support for the proposed removal of selected forecast capital expenditure from BHP Billiton and EUCV.[414] However, both these parties expressed concern that the Commission would not verify other expenditure as being necessary and cost effective prior to it being included in the asset base. Amcor and PaperlinX added that 'the ACCC could well be encouraging inefficient investments, and sets a dangerous precedent for future regulatory reviews'.[415]

GasNet has responded to the Commission's Draft Decision proposal not to accept three forecast capital expenditure items.

First, GasNet acknowledged that the amended forecast demand figures are unlikely to support the construction of the Brooklyn loop. Consequently, GasNet proposed that in the event that the project is undertaken, it would apply to the Commission to include the expenditure in the PTS asset base.[416]

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[414] BHP Billiton submission, 13 September 2002; EUCV submission, 13 September 2002, p. 11.

[415] Amcor and PaperlinX submission, 13 September 2002, p. 9.

[416] GasNet submission 20 September 2002, p. 31.

With respect to the second project, GasNet stated:

> In relation to the Stage 2 Lurgi line rehabilitation forecasts, GasNet understands that the Commission may be reluctant to approve these costs when the scope of work and range of costs are uncertain. Accordingly, GasNet will remove this amount from its capital expenditure forecasts.[417]

Again, GasNet noted that it will apply to the Commission to include any stage 2 expenditure that is required in the asset base.

Third, GasNet 'agrees with the Commission that if amendments to GasNet's extensions and expansions policy to allow service lines to be excluded from the Access Arrangement are approved, it may be unreasonable to include the cost of service lines in the forecast capital expenditure'.[418] Consequently, GasNet has accepted the removal of the proposed forecast capital expenditure. Any service lines that it builds and elects to include in the access arrangement will be subject to a revision application to the access arrangement.

Subsequent to the Commission's Draft Decision VENCorp notified GasNet that it required three gas chromatographs to be installed on the PTS at, or near, North Paaratte, Lara and Brooklyn at a total cost of $902 000 (in 2002 dollars).[419] These gas chromatographs are now required due to the more complex flaws possible in the PTS with various supply points. The heating value of the gas flowing at certain points is required to be calculated with accuracy to ensure that all gas supplied into the PTS meets the requirements of the MSOR.[420] GasNet plans to carry out this forecast expenditure in 2003 and has requested that this new expenditure be included in the calculations of revenues and reference tariffs for the PTS.

GasNet has also advised that it considers that the forecast capital expenditure meets the requirements of both section 8.16(a) and 8.16(b)(iii) of the Code. It regards the expenditure as prudent on the basis that it is required by VENCorp and the costs are based on similar installations. In relation to section 8.16(b)(iii) of the Code, the safety and integrity test, GasNet stated that 'in the absence of these facilities the transmission service would be unreliable because the quantities of delivered energy would not be measurable with sufficient accuracy as required by the MSO Rules'.[421]

6.3.7 Final Decision

As discussed above in section 6.3.5, the Commission proposed to accept the majority of GasNet's proposed forecast capital expenditure for 2003 to 2007. However, the Draft Decision proposed that three items included in GasNet's proposal be excluded from the calculation of revenues. These items are:

- Brooklyn loop;

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[417] ibid.

[418] ibid.

[419] VENCorp letter to GasNet, 11 September 2002 (GasNet submission, 20 September 2002, Annexure C).

[420] GasNet submission, 20 September 2002, p. 32.

[421] GasNet information to Commission, 10 October 2002.

- stage 2 of the Lurgi pipeline refurbishment; and
- service lines.

The Commission considers that these items as proposed are unlikely to meet the requirements of section 8.16 of the Code. Consequently, pursuant to section 8.20, the Commission does not consider it appropriate to calculate reference tariffs on the basis of the forecast expenditure. The Commission also notes that as these items are unlikely to satisfy section 8.16 it is not in the interest of users (pursuant to section 2.24(f) of the Code) to pay tariffs that recover the proposed expenditure. In addition, the inclusion of these items would not encourage efficient investment in the pipeline (see section 8.1(d)) of the Code.

As outlined above, GasNet has agreed with the relevant proposed amendments included in the Draft Decision. Accordingly, for the reasons discussed above and provided in the Draft Decision, an amendment to the proposed revised access arrangement is required (see conclusion of this discussion).

Amendment 28

GasNet must amend section 3.6 of its revised access arrangement information to exclude from the calculation of tariffs forecast expenditure relating to the Brooklyn loop, stage two of the proposed Lurgi pipeline rehabilitation project, and possible service lines.

As noted in the Commission's Draft Decision, and by GasNet, if any of these projects (or any other projects not currently forecast) are undertaken during the 2003 to 2007 period GasNet may elect to apply to the Commission for a revision to the access arrangement to include the expenditure undertaken in the asset base. The Commission must find that the expenditure satisfies the requirements of section 8.16 of the Code for it to be incorporated into the capital base and the access arrangement. This assessment process would be public and carried out in accordance with section 2 of the Code.[422]

The Commission has considered the proposal by GasNet to include forecast capital expenditure in relation to the three gas chromatographs, noting that interested parties have had limited opportunity to comment. The analysis by the Commission's technical adviser indicates that the expenditure is not unreasonable and is likely to be prudent. The Commission is also satisfied that in the future, when GasNet proposes to include the expenditure in the asset base, section 8.16(b)(iii) is reasonably likely to be satisfied. Accordingly, the Commission has decided to accept the proposed forecast capital expenditure for 2003.

Conclusion

The total forecast capital expenditure for 2003 to 2007 accepted by the Commission as meeting the requirements of section 8.20 of the Code is $47.36 million and is set out in the table below. The calculation of GasNet's revenue for the period will include this

[422] The Commission has to date carried out assessments of two unscheduled proposed revisions to an access arrangement. These were both in respect of new assets on the PTS – the Interconnect Assets and the Southwest Pipeline.

expenditure. These figures are indicative only as they include GasNet's proposed escalation factor (expected inflation) of 2.5 per cent.

Table 6.14: Approved forecast capital expenditure, 2003 to 2007

	$ million[a]					
	2003	**2004**	**2005**	**2006**	**2007**	**Total**
Gooding compressor			6.49	8.13	7.95	22.57
Lurgi pipeline	2.05	2.10	1.55			5.70
City gates		2.36	2.53	4.41		9.30
Wollert compressor		1.50	1.82			3.32
Maintenance	1.90	1.43	0.51	0.59	1.12	5.55
Gas chromatographs	0.92					0.92
Total	4.87	7.39	12.90	13.13	9.07	47.36

Source: GasNet access arrangement information, 27 March 2002, p. 12; information to Commission, 10 October 2002.
Note: (a) All in nominal dollars for years ending 30 June.

Following the Commission's amendments on forecast capital expenditure and expected inflation the access arrangement information provided in March 2002 will no longer be correct. In addition, it does not include the forecast expenditure on the gas chromatographs. Accordingly, GasNet must amend the access arrangement information and its revenue model to fully reflect this Final Decision.

Amendment 29

GasNet must amend clause 3.6 of its revised access arrangement information to include the approved forecast capital expenditure for the three proposed gas chromatographs. It must also reflect the expected inflation rate specified in the Final Decision. These changes must also be incorporated into the revenue model used to determine reference tariffs for 2003 to 2007.

The Commission expects that at the next scheduled review of the access arrangement, each capital project that has been undertaken by GasNet will be assessed against section 8.16 of the Code (in a manner similar to that discussed in chapter 4 of this Final Decision). The projects and expenditure that are found to satisfy the Code will then become part of the PTS access arrangement and be included in the asset base.

6.4 Depreciation

6.4.1 Code requirements

A service provider must establish a depreciation schedule for the assets that are included in the capital base. This is to consist of a number of schedules for each asset or group of assets. Pursuant to section 8.33 of the Code, under the Cost of Service approach used for the PTS, the depreciation schedule must result in:

- reference tariffs that change over time consistent with the efficient growth of the market for the reference service. This may include 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 occurring over the economic life of the assets with progressive adjustments where appropriate to reflect changes in economic lives of the assets; and
- the asset being depreciated only once so that total depreciation is equivalent to the valuation of the asset at the time it was when initially incorporated in the capital base (subject to an adjustment for inflation, where appropriate).

Pursuant to section 8.5A of the Code depreciation may be expressed on a nominal basis, a real basis or in any other manner that deals with the effect of inflation provided that it is specified in the access arrangement, applied consistently and approved by the regulator.

6.4.2 Current access arrangement provisions

Reference tariffs for the current access arrangement period have been determined using real straight line depreciation on the basis of standard asset lives. In accordance with the current cost accounting approach adopted by the service provider, depreciation costs are adjusted to reflect the revaluation of assets due to inflation. The Commission stated that it accepted this approach as it resulted in fairly level tariffs over time.[423]

To calculate depreciation for the pipeline it was assumed that the economic life of the Longford pipeline concluded in 2030 and that of the other pipeline assets concluded in 2033. That is, at the time of the 1998 Final Decision, the assets had a remaining economic life of 32 and 35 years respectively.

6.4.3 GasNet proposal

GasNet proposes to retain real straight line depreciation with the exception of the Southwest Pipeline.[424] As permitted by section 8.33(c) of the Code, GasNet has reviewed the basis of the economic lives of the assets with respect to recent estimates of gas reserves and other events.

GasNet commissioned Saturn Resources to review and update the analysis of asset lives it conducted prior to approval of the access arrangements. The current report considered the impact of gas reserves, bypass risk, rezoning and forced relocations, and unexpected and unspecified factors. These factors were used to adjust the remaining technical lives of the asset groups to obtain the remaining economic lives of the assets. Following from the Saturn Resources report GasNet adjusted the expected end of life of the Longford pipeline from 2030 to 2023. In addition, it proposed that the life of the

[423] ACCC, 1998 Final Decision, p. 45.

[424] GasNet states that the Southwest Pipeline depreciation allowance will be levelised over the first 20 years. GasNet access arrangement information, 27 March 2002, p. 6.

Southwest Pipeline conclude in 2052. An end of life of 2033 was still regarded as appropriate for the remaining pipeline assets.

As a result, the depreciation schedule proposed for the forthcoming access arrangement period is provided in Table 6.15 below.

Table 6.15: Proposed annual depreciation allowances, 2003 to 2007

	$ million[a]				
	2003	**2004**	**2005**	**2006**	**2007**
Pipelines	14.45	15.04	15.65	16.40	17.33
Compressors	4.24	4.50	4.95	4.99	4.51
System control facilities	0.90	0.94	1.10	1.30	1.37
Odourisation	0.01	0.01	0.01	0.01	0.02
Gas quality	0.02	0.02	0.02	0.02	0.02
General land and building	0.18	0.18	0.19	0.19	0.19
Other	0.27	0.26	0.23	0.19	0.17
Total	20.10	21.00	22.20	23.10	23.60

Source: GasNet, Erratum, 19 July 2002.
Note: (a) All in nominal dollars.

As noted above, GasNet proposed a remaining economic life of 50 years for the Southwest Pipeline, ending in 2052. This reflects 'the fact that the Southwest Pipeline is a new pipeline in competition with other gas injection pipelines, and that a reasonable tariff is required in order to encourage growth on the pipeline'. In addition, GasNet proposes to levelise the revenue requirement for the Southwest Pipeline for the initial 20 years of the pipeline's life. As a result, the depreciation allowance for the Southwest Pipeline will be negative over the first period.[425] GasNet notes that the anticipated life of the Southwest Pipeline was not reduced in light of the anticipated depletion of the Otway Basin. It considers that the Southwest Pipeline will have an on-going value to the system as it is connected to the UGS.[426]

6.4.4 Submissions to Issues Paper

Origin did not consider that there was sufficient information available to support the proposed change in the asset life for the Longford pipeline. It considered that the basic assumptions that were originally used to establish the asset's life had not changed and that new sources of gas would not have a substantial impact on the economic life of the pipeline.[427]

TXU also commented on the Longford pipeline depreciation, suggesting that it should remain as it is. It noted that Esso-BHP had recently embarked on the largest survey of

[425] GasNet submission, 27 March 2002, schedule 5, p. 52.

[426] GasNet response to submissions, 12 June 2002, p. 19.

[427] Origin submission, 17 May 2002, p. 5.

Bass Strait undertaken with the possibility that the earliest new discovery could start between 2006-2009.[428]

BHP Billiton considered that the depreciation period for Longford should be what was established for the initial access arrangement period or longer. It suggested that the proposal to depreciate the Longford pipeline faster than the Southwest Pipeline should be rejected. BHP Billiton regarded the economic life of the Southwest Pipeline to be limited by the reserves of the Otway Basin and accordingly suggests that the Southwest Pipeline would have a relatively short life.[429]

Amcor and PaperlinX also noted that the 'more rapid depreciation adds costs onto Longford related assets and reduces that relative costs of SWP assets'. In addition, they commented that 'the Saturn report ignores undiscovered Gippsland reserves in its economic evaluation'. Amcor and PaperlinX suggested that the following should be considered in relation to depreciation: the expectation of higher reserves for the Gippsland Basin leading to the EGP and Longford to Tasmania pipelines; the substantial exploration recently announced by Esso-BHP Billiton; and the current capacity of the EGP.[430]

In particular reference to the proposed depreciation schedule for the Southwest Pipeline, Esso suggested that the economic life of the Southwest Pipeline had been determined with the aim of reducing the tariff to apply to that asset. It noted that 'It would appear somewhat unusual to determine the economic life of an asset on the basis of the desired tariff profile'.[431]

6.4.5 Draft Decision

The Commission's Draft Decision agreed with GasNet that retention of real straight line depreciation for the majority of assets included in the capital base is appropriate for the forthcoming access arrangement period.

As outlined above, GasNet proposed to reduce the remaining economic life for the Longford to Pakenham pipeline on the basis that reserves in the Gippsland Basin will deplete significantly as they supply Victoria, NSW and Tasmania over the next 20 years. The Commission acknowledged that the Gippsland Basin will be used to supply gas into Victoria, NSW and Tasmania in the future. While this scenario may suggest an increased rate of depletion of reserves, Esso-BHP Billiton recently announced the commencement of an extensive study of Bass Strait for natural gas. The Commission understood that the seismic survey is expected to cost approximately $60 million and will be followed by a two year drilling program costing approximately $250 million.[432]

BHP Billiton reviewed the Saturn report as well as other various sources of information regarding reserves and the supply-demand balance in south east Australia. It suggested

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428 TXU submission, 31 May 2002, pp. 28-29.

429 BHP Billiton submission, 21 June 2002, pp. 14-15; Amcor and PaperlinX submission, 24 June 2002, p. 11.

430 Amcor and PaperlinX submission, 24 June 2002, p. 11.

431 ExxonMobil submission, 5 June 2002, p. 26.

432 'Banking on a new boom in Bass Strait' *Australian Financial Review*, 8 April 2002, p. 14.

that gas producers tend to understate reserves for a variety of commercial reasons and that historically ‘gas reserves have increased or matched supply even when growth in the demand for the gas increases’. BHP Billiton concluded:

> There is no doubt that there is significant imprecision in forecasting gas demand and gas reserves, but the assumptions underlying the Saturn report would seem to overstate the expected demand for gas in the eastern States, and at the same time, understate the potential reserves of natural gas to meet demand in the southeastern States.[433]

The impact of moving the end date of the Longford pipeline’s economic life is that current users of the PTS would face increased tariffs to recover the additional revenue required by GasNet. While this additional revenue requirement is significant in total it would be spread over all users, resulting in a small increase in tariffs for each user.

The Draft Decision noted that generally the Commission would regard asset owners as being in the best position to determine the appropriate effective life and depreciation profile for their assets. However, in this case the Commission concluded that the reduced life for the Longford to Pakenham pipeline would not reflect the likely life of the Gippsland Basin reserves and would be inconsistent with the expected lives of the withdrawal pipelines and distribution systems dependant on it. Consequently, the Commission considered that it would be inappropriate to bring forward the end date of the Longford pipeline life to 2023 (from 2030) and an amendment was proposed in the Draft Decision.

GasNet proposed a remaining economic life of 50 years (ending in 2052) for the Southwest Pipeline. However, BHP Billiton suggested that the Southwest Pipeline will have a relatively short economic life. The Southwest Pipeline may be predominantly used for the transportation of Otway Basin gas in the short to medium term although further development of the Otway Basin may arise in the future.

The Draft Decision also noted that the future development of the gas market in south east Australia may call on greater use of the UGS (and consequently the Southwest Pipeline) than is presently anticipated. It also acknowledged that a long remaining economic life for the Southwest Pipeline reduces the depreciation allowance to be included in the revenue calculations and allows a lower initial tariff. This may be appropriate for a relatively new pipeline that is yet to establish its market.

On balance, the Commission’s Draft Decision proposed to accept the proposed remaining economic life for the Southwest Pipeline of 50 years ending in 2052.

The remaining assets of the PTS have been allocated an economic depreciation of 31 years ending in 2033. As in the first access arrangement period, this results from an averaging of the remaining assets that have a variety of remaining lives. This results in the bulk of the PTS having a different remaining economic life than the Southwest Pipeline. However, the Commission concluded that uncertainties surrounding the market in the future do not support altering the economic life of the PTS at present and it proposed to accept GasNet’s continued use of the economic life ending in 2033 for the remaining portion of the PTS to calculate the depreciation schedule.

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433 BHP Billiton submission, 18 July 2002, p. 9.

6.4.6 Response to Draft Decision

The Commission's proposal to use an asset life for the Longford to Pakenham pipeline ending in 2030 attracted some support from interested parties. ExxonMobil stated:

> We believe an economic life of 2030 for the Longford-Dandenong pipeline to be conservative with an even longer life supportable through continued utilisation due to:
>
> a) significant exploration activities that are being conducted in the Gippsland Bass Strait region with potential for new or additional reserves to be found,
>
> b) interconnection to other markets via the EGP and TGP for other sources of gas well beyond the depletion of any Gippsland gas fields, and
>
> c) future potential gas storages utilising depleted reservoirs in the Gippsland Bass Strait region.[434]

The EUAA also agreed with the proposed amendment, noting that 'the basic assumptions that were originally used to determine the economic life of this pipeline in 1998 have not changed'. It also noted that 'both Esso and BHP-Billiton disagree with the findings of the Saturn report'.[435] BHP Billiton stated that the key error of the Saturn report 'was to assume that demand for NSW, Victoria and Tasmania from Gippsland basin was related to the capacity of the pipelines leading from Longford, a patently incorrect notion'. It noted that as there is 'inherent instability of identifying specific gas supply from one basin' it used a 'holistic' view of reserves and demand for south east Australia.[436] The EUCV also concurred with the Commission's Draft Decision on this matter.[437]

In contrast, GasNet did not accept the proposed amendment relating to the life of the Longford pipeline. It refers to a recent report from ABARE that it regarded as 'consistent with the proposal put forward by Saturn Resources and GasNet. ABARE concludes that it is unlikely that the Gippsland basin will maintain production beyond 2020 unless substantial further discoveries are made'.[438]

GasNet acknowledged that further discoveries would extend the life of the Longford pipeline. However, it noted that the assessment carried out by Saturn Resources made an allowance for undiscovered reserves of 3000 PJ (which is 35 per cent of the current reserve estimates). GasNet considered this to be a reasonable assumption and concluded that:

> Irrespective of the assumption made about undiscovered reserves, GasNet believes that the economic life of a regulated pipeline should be based on reliable, scientifically established reserve estimates ... and not on possible outcomes of speculative exploration activity.[439]

In reference to BHP Billiton's 'holistic' approach, GasNet stated that the 'methodology employed by BHP Billiton is not different to that used by Saturn and ABARE. For

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434 ExxonMobil submission, 10 September 2002, p. 2.

435 EUAA submission, 20 September 2002, p. 4.

436 BHP Billiton submission, 11 October 2002, pp. 20-21.

437 EUCV submission, 13 September 2002, p. 8.

438 GasNet submission, 20 September 2002, p. 33.

439 ibid., p. 35.

example, ABARE calculates a common depletion date for the Eastern Australian reserves of around 2020, rather than field specific dates'.[440]

While, as noted above, ExxonMobil agreed with the Commission's Draft Decision assessment of the life of the Longford pipeline, it did 'not understand why the SWP economic life should be considered longer than that of the Longford-Dandenong pipeline'.[441] The EUCV also expressed concern regarding the proposed asset life of the Southwest pipeline, suggesting that there is some doubt as to the life of the Otway Basin gas fields.[442]

6.4.7 Final Decision

The Commission has reviewed the information presented for the Draft Decision regarding the economic life of the Longford to Pakenham pipeline and notes the following:

- the asset lives established for the initial access arrangement period appear to be based on proved and probable reserves for the Gippsland Basin known at the time. However, this estimate was then augmented and the end of life for the Longford pipeline was extended to 2030;[443]
- while Esso-BHP Billiton are currently conducting substantial exploration activity, the success of the project cannot be determined in any reliable manner at present; and
- BHP Billiton assumed that the EGP, which supplies Bass Strait gas to NSW, would capture 25 per cent of total NSW demand. However, the EGP can, if compressed, carry 90 PJ per year which is approximately 50 per cent of NSW demand in 2012.[444]

Subsequent to the Commission's Draft Decision, ABARE released its latest report on gas supply and demand. With respect to Victoria, the ABARE study assumed relatively modest growth in gas consumption from 1999-2000 to 2019-2020. While consumption in Victoria is high compared to other states, 'the results indicate that the majority of Victoria's needs will continue to be met from local Gippsland basin supplies for the foreseeable future'.[445] ABARE anticipates interstate supplies to be less than 10 per cent of the total demand for Victoria.

In addition, ABARE notes that the Gippsland Basin may also supply South Australia (in its high demand scenario) during the period to 2019-2020. It also expects the Gippsland Basin to have an increasing role in supplying gas into NSW. However, it suggests that while south east Australia will be able to be supplied from current fields until 2019-2020, 'almost all eastern Australian gas reserves are depleted or nearing

[440] GasNet submission, 18 October 2002, p. 3.

[441] ExxonMobil submission, 10 September 2002, p. 2.

[442] EUCV submission, 13 September 2002, p. 8.

[443] GasNet response to submissions, 17 July 2002, pp. 16-17.

[444] GasNet response to submissions, 24 July 2002, pp. 7-8.

[445] M Fainstein, J Harman and A Dickson, *Australian gas supply and demand balance to 2019-20*, ABARE report to the Commonwealth Department of Industry, Tourism and Resources, August 2002, p. 29.

depletion with only an estimated three years worth of production remaining in 2019-20'.[446] ABARE acknowledges this is a conservative analysis and the conclusion may be overstated and should be interpreted with some caution.

The Commission acknowledges GasNet's view that this information from ABARE appears to support its proposal to reduce the economic life of the Longford pipeline. It also notes that this study conflicts with the views of a number of interested parties, notably the producers.

Accordingly, the Commission must balance these views to determine the most appropriate economic life (and depreciation schedule) for the Longford pipeline. If the current economic life is retained, as proposed in the Draft Decision, a number of interested parties would support this approach and there would be no short term increase in tariffs as proposed by GasNet. This would appear to be in the interests of users of the pipeline pursuant to section 2.24(f) of the Code. However, if GasNet's proposal is adopted and the economic life is reduced the target revenue for GasNet will increase by approximately $1 million per year for each year of the forthcoming access arrangement period. That is, tariffs for all users will increase by a small amount in the short term but be lower than otherwise in the longer term. In effect, the change to the depreciation schedule moves future revenues to the immediate access arrangement period. GasNet appears to place a high value on this aspect of its proposal and it could be regarded as being in its legitimate business interests in relation to section 2.24(a) of the Code.

While there are conflicting views on the economic life of the Longford pipeline, the Commission has concluded that it will place greater weight on the ABARE report and, with reference to section 2.24(a) of the Code, GasNet's interests. Accordingly, the Commission will not require GasNet to retain the current economic life of the Longford pipeline. Instead, an economic life ending in 2023 is to be used for the forthcoming access arrangement period.

It should be noted that if future studies indicate a change in the gas reserves of the Gippsland Basin or any other factors that impact on the life of the Longford pipeline then, pursuant to section 8.33 of the Code, the economic life of the Longford pipeline may be altered as part of a future revisions assessment process.

As noted above, ExxonMobil and EUCV did not agree with the Commission's proposal to accept an economic life for the Southwest Pipeline of 50 years. The Commission considers that at this early stage of the pipeline's life it is most appropriate to use a long asset life particularly when there is considerable uncertainty regarding the state of the Victorian gas market so far into the future. The Commission regards this as an appropriate assumption for the Southwest Pipeline. It is also noted that a long asset life reduces the depreciation charge for this pipeline and consequently the relevant tariff. This has a similar effect in the short term as using back-ended depreciation. Generally, a lower tariff in the initial years of a pipelines life assists in the development of its market. In view of section 2.24(a) of the Code, the Commission considers this is an

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[446] ibid., p. 3.

appropriate consideration. The appropriate economic life of the Southwest Pipeline will be reassessed in the future as provided for under section 8.33 of the Code.

The Commission's Draft Decision proposed to retain the current economic life, ending in 2033, for the remaining parts of the PTS. The Commission remains of the view that this is appropriate.

As a result of various amendments specified in this Final Decision (such as inflation and forecast capital expenditure), the proposed access arrangement information does not contain a correct depreciation schedule for the period 2003 to 2007. Accordingly, the Commission requires the access arrangement information to be amended and these amendments to be reflected in GasNet's revenue model.

Amendment 30

GasNet must amend clause 3.3 of the revised access arrangement information regarding depreciation to reflect the Final Decision. These changes must also be included in the revenue model used to determine reference tariffs.

An indicative depreciation schedule is set out in Table 6.16 below. This includes an extra depreciation allowance for the normalisation calculation discussed in chapter 5 of this Final Decision. Normalisation involves smoothing revenue requirements over the life of the assets to avoid a sharp increase in the revenue requirement as taxes become payable. To remove the volatility in revenues a normalisation process is used to alter the depreciation profile of the business and smooth the revenues.

Table 6.16: Approved annual depreciation allowances, 2003 to 2007

	$ million[a]				
	2003	**2004**	**2005**	**2006**	**2007**
Pipelines	12.96	13.41	13.87	14.29	14.69
Compressors	3.89	4.11	4.52	4.51	3.98
System control facilities	0.80	0.84	0.99	1.17	1.27
Odourisation	0.01	0.01	0.01	0.01	0.01
Gas quality	0.06	0.11	0.11	0.12	0.12
General land and building	0.70	0.71	0.73	0.75	0.76
Other	0.43	0.42	0.39	0.36	0.36
Total of assets	18.22	18.97	19.97	20.53	20.50
Normalisation	2.15	2.32	2.52	2.75	3.00
Total	20.37	21.29	22.49	23.23	23.50

Source: ACCC analysis; GasNet regulatory asset base model.
Note: (a) All in end of year nominal dollars (expected inflation for the period of 2.16 per cent).

6.5 Inflation

6.5.1 Code requirements

Section 8.5A of the Code provides that the amount of total revenue can be determined under either a nominal or real approach or ‘on any other basis in dealing with the effects of inflation’ provided that it is specified in the access arrangement, approved by the regulator, and applied consistently.

6.5.2 Current access arrangement provisions

The reference tariff methodology for the initial access arrangement period uses a real framework. In 1998 an expected inflation rate of 2.5 per cent was used to calculate the expected revenues over the access arrangement period. An expected average tariff path was also developed on the same basis. The methodology provides for actual tariffs to be calculated annually according to the change in CPI from one September quarter to the next. Similarly, at the conclusion of the initial access arrangement period, the capital base is to be adjusted for actual inflation.

6.5.3 GasNet proposal

GasNet has applied actual inflation in the roll forward of the capital base which was established in 1998 for the initial access arrangement period as anticipated in the current provisions of the access arrangement.[447] This is part of the calculation to determine the capital base for the commencement of the forthcoming access arrangement period.

GasNet has proposed to continue with a real rate of return methodology. GasNet has used an annual inflation rate of 2.5 per cent to escalate the capital base within the second access arrangement period for the purposes of its application.[448] However, as with the current methodology, at the conclusion of this access arrangement period, an adjustment to the capital base will be made to reflect actual inflation. This will also impact on the inflation component of depreciation.

6.5.4 Submissions to Issues Paper

The Commission did not received any comments from interested parties regarding this issue.

6.5.5 Draft Decision

The Commission assessed GasNet’s inflation adjustments to the capital base over the initial access arrangement period. It determined that the appropriate adjustments have been made and that actual inflation is reflected in the model and the resulting capital base values.

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447 GasNet submission, 27 March 2002, p. 44.

448 GasNet access arrangement information, 27 March 2002, p. 8.

For the Draft Decision the Commission used the expected inflation rate determined by the relevant bond rates at that time, 2.5 per cent, to adjust the capital base through the second access arrangement period.

6.5.6 Response to the Draft Decision

The Commission received comments from interested parties regarding the inflation adjustment made to the capital base for the initial access arrangement period. BHP Billiton, EUCV and Amcor and PaperlinX claimed that the GST inflation spike had been ignored in the adjustment to the capital base. The parties argued that the inflation adjustment to the capital base should exclude the impact of the introduction of the GST on inflation.[449]

6.5.7 Final Decision

As noted above, the adjustments to obtain the correct value for the capital base for the commencement of the forthcoming access arrangement period include an adjustment for actual inflation for the initial access arrangement period. The Commission's Draft Decision concluded that this had been carried out correctly by GasNet.

To remove the impact of the GST from the adjustment to the capital base, as recommended by some interested parties, would result in an erosion of the real (inflation adjusted) value of GasNet's assets. This would be inconsistent with its legitimate business interests (pursuant to section 2.24(a) of the Code).

GasNet has also used a forecast inflation rate of 2.5 per cent for 2002 in its calculation of the regulatory asset base at the beginning of 2003. The Commission has required it to replace this forecast with the actual figures known (see section 4.1.7 of this Final Decision).

With the adoption of this change, the Commission considers that the inflation adjustment required for the initial access arrangement period will have been carried out appropriately and no further change to GasNet's method will be required.

Expected inflation for the forthcoming access arrangement period has been calculated as 2.16 per cent for this Final Decision.[450] This figure is used in the CAPM and in the revenue model where, for example, escalation of the capital base is required through the period.

6.6 Revenue calculation

Accompanying the proposed revised access arrangement, GasNet provided the Commission with a confidential model which calculates the proposed revenue requirement. The Commission has audited the model and found a number of errors.

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[449] BHP Billiton submission, 13 September 2002, p. 13; EUCV submission, 13 September 2002, p. 8; Amcor and PaperlinX submission, 13 September 2002, p. 9.

[450] See section 5.5 of this Final Decision document.

Many of these have been accepted by GasNet which has subsequently provided the Commission with revisions of the model.

As noted elsewhere (section 6.2.5), the Commission's modelling contains certain simplifying assumptions (which are generally to the benefit of the regulated entity). They include the assumption that receipt of revenues, depreciation, operating and maintenance (O&M) expenditure and capital expenditure all occur on the last day of the year.[451] Consequently, return on capital is calculated on the opening RAB balance rather than, for example, an average of the opening and closing balances which would reflect an assumption that revenues and costs occurred on average in the middle of the year.

GasNet's modelling reflects the Commission's assumptions (that depreciation and capital expenditure occur at the end of the year) by calculating return on the opening balance of the RAB. However, inconsistent with this, GasNet's modelling also includes a return (at half rate) on capital expenditure for the year in which it occurs, and half a year of depreciation, which reflects the assumption that capital expenditure occurred on average half way through the year. While this particular assumption may be closer to actual occurrence, it gives an inappropriate increase in revenue to GasNet when combined with the Commission's other assumptions. While it is a legitimate business interest of GasNet to seek higher revenue (section 2.24(a) of the Code), this needs to be balanced against the interests of users and prospective users (section 2.24(f)) and the objective of having tariffs at an efficient level (section 2.24(e)). As adhering to the Commission's assumptions will still provide GasNet with the opportunity to earn a revenue stream that recovers efficient costs (section 8.1(a)), the Commission has decided that GasNet should remove from its revenue calculations any return on capital expenditure or depreciation of capital expenditure in the year in which it is forecast to occur.

Amendment 31

GasNet must correct its revenue model so that no return on capital or depreciation is calculated on capital expenditure in the year in which it is forecast to occur. Capital expenditure should be added to the opening balance of the asset base in the subsequent year at the forecast mid-year expenditure amount (as currently provided to the Commission) inflated to the end of the year.

6.7 Pass-through events

As noted in the discussion on reference tariffs, GasNet has proposed a pass-through mechanism to avoid going through the Code's section 2 review process for specific cost changes within the second access arrangement period. The mechanism proposed by GasNet includes a pass through for tax increases, increased regulatory requirements and a rise in insurance premiums. The proposed mechanism would be asymmetric, and the Commission would only have 20 days to approve any pass through adjustment.

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[451] See, for example, ACCC, *Final Decision: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*,12 September 2001, pp. 29-30.

The Commission considers that in principle a pass-through mechanism may be appropriate, but has proposed a number of amendments to the GasNet mechanism. These amendments are detailed in section 3 of this Draft Decision.

7. Volumes and revenue

7.1 Volumes

7.1.1 Code requirements

The Code (section 8.2(e)) requires that any forecasts used in setting the reference tariff should represent ‘best estimates arrived at on a reasonable basis’.

7.1.2 Current access arrangement provisions

Volume forecasts for the first access arrangement period were based on a forecast developed by GASCOR in 1997 and adjusted to take into account factors such as new developments (for example, Carisbrook and the Interconnect).[452]

7.1.3 GasNet proposal

Both GasNet and VENCorp base their demand forecasts on those published in the VENCorp Annual Planning Review. The annual demand forecasts incorporate a substantial revision to the temperature trend used for earlier projections which has the effect of lowering demand expectations. GasNet proposes to adjust these estimates to account for a warming trend in Melbourne which it says arises from a combination of an enhanced greenhouse effect and an urban heat island effect. GasNet states that the effect of this adjustment is to reduce the forecast annual load in 2007 by approximately 1.2 PJ. GasNet provided a consultancy report by the CSIRO as an annexure to it submission in support of this adjustment.[453]

GasNet noted that the VENCorp Annual Planning Review had not identified any associated trend in peak day flows. GasNet commented:

> However, the coldest day EDD [effective degree day] is more variable year to year than the annual EDD and therefore it is more difficult to identify whether a trend is present. As it is likely that such a trend is likely to be very small, GasNet currently accepts the forecasts provided by VENCorp without modification.[454]

Table 7.1: GasNet’s forecast demand, 2003 to 2007

Demand and volume	2003	2004	2005	2006	2007
Peak demand (TJ/day)	1 132	1 174	1 209	1 235	1 257
Annual volume (PJ)[a]	216.2	225.3	232.7	237.2	241.3

Source: GasNet access arrangement information, 27 March 2002, p. 15.
Note: (a) Excludes storage refills of 3.6, 3.6, 4.3, 3.2 and 3.4 PJ over this period. GasNet submission, 27 March 2002, p. 105.

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452 TPA additional supplementary information, 16 March 1998, p. 18.

453 CSIRO, *Projected changes in temperature and heating-days for Melbourne, 2003-2007,* November 2001.

454 GasNet submission, 27 March 2002, p. 106.

GasNet disaggregated its total demand forecasts, provided here in Table 7.1, by zone (see Table 7.2) on the basis of a range of assumptions including:

- Esso/BHP Billiton flows from Longford would fall from a maximum daily quantity (MDQ) of 830 TJ/day to 810 TJ/day;
- 35 TJ/day from the Baleen/Patricia/Kipper fields would be injected via a connection facility at Longford known as the VicHub (after being processed at Orbost and backhauled along the EGP);
- imports from Culcairn would fall from 28 TJ/day to 17 TJ/day;
- on-shore Otway Basin production would grow from 25 TJ/day to approximately 55 TJ/day before declining as production grows from Thylacine and Geographe to 60 TJ/day in 2006 and 90 TJ/day in 2007; and
- the Yolla project would not proceed.[455]

Table 7.2: Forecast zonal volumes, 2002 to 2007

	TJ/year					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
La Trobe	14 820	11 875	14 387	17 367	17 886	18 204
Tyers		2 390	3 213	3 337	3 762	4 388
Lurgi	1 475	1 521	1 564	1 611	1 659	1 709
Metro	166 110	170 437	174 858	178 091	180 640	182 895
Calder	8 435	9 509	9 907	10 181	10 396	10 536
Carisbrook	760					
South Hume	842	874	909	933	952	961
Echuca	6 735	6 986	7 262	7 451	7 611	7 691
North Hume	6 868	2 290	2 381	2 442	2 495	2 521
Wodonga		4 707	4 754	4 801	4 849	4 898
Murray Valley	829	1 094	1 364	1 608	1 849	2 127
Barnawartha	1 177					
Southwest Pipeline	520	570	573	578	681	784
Western	3 757	1 894	1 979	2 060	2 144	2 228
Koroit		580	606	631	656	682
Allansford		1 463	1 529	1 592	1 657	1 723
Total	212 328	216 190	225 287	232 683	237 239	241 346

Source: GasNet Erratum, 15 May 2002, p. 2.

455 ibid., schedule 6, p. 63.

7.1.4 Submissions to Issues Paper

VENCorp noted that the demand forecasts provided by it and by GasNet are derived from the VENCorp Annual Planning Review (30 November 2001) forecasts which exclude UGS withdrawals and NSW exports. VENCorp has provided the calendar year forecasts shown in Table 7.3 below to allow a direct comparison with data from GasNet.

Table 7.3: Comparison of GasNet and VENCorp demand forecasts

	PJ[a]		
Year	**GasNet**	**VENCorp/NIEIR[b]**	**Difference**
2002		211.4	
2003	216.2	216.6	0.4
2004	225.3	225.9	0.6
2005	232.7	233.5	0.8
2006	237.2	238.3	1.1
2007	241.3	242.6	1.3

Source: VENCorp submission, 13 May 2002, p. 20.

Notes: (a) Forecasts exclude UGS withdrawals and exports to NSW.

(b) VENCorp's Annual Planning Review forecasts were developed in conjunction with the National Institute of Economic and Industry Research (NIEIR).

VENCorp submitted that the difference in annual demand forecasts reflects different assumptions in respect of urban and global warming effects but is not material when other factors are taken into account:

> In summary, VENCorp has corrected forecast loads for the trend in temperature observations due to localised urban heating effects whereas GasNet's adjustments to the VENCorp forecasts assumes there is a heating effect across the PTS as a whole.
>
> The differences are not material when compared with the normal annual load variations due to weather cycles and load forecast uncertainty over 5 years.[456]

VENCorp also provided a comparison of peak day forecasts (see Table 7.4 below). It submitted that the differences between the two sets of forecasts are essentially due to the difference in reference year (that is, between calendar and financial years). VENCorp forecasts that the peak winter day occurs in July or August which means, for example, that the 2004 calendar year peak day would occur in the 2004-05 financial year.

[456] VENCorp submission, 13 May 2002, p. 21.

Table 7.4: Comparison of GasNet and VENCorp peak day demand forecasts

	TJ				
Peak day	**2003**	**2004**	**2005**	**2006**	**2007**
GasNet[a]	1 132	1 174	1 209	1 235	1 257
VENCorp[b]	1 104	1 133	1 170	1 208	1 236

Source: VENCorp submission, 13 May 2002, p. 21.
Notes: (a) Calendar year.
(b) Financial year.

Table 7.5 below provides VENCorp's forecasts of exports to NSW and withdrawals from UGS. It complements the data provided in Table 7.3.

Table 7.5: Forecast exports to NSW and UGS, 2001-2002 to 2007-2008

	TJ		
Year[a]	**NSW exports**	**UGS**	**Total**
2002	500	3 277	3 777
2003	500	4 499	4 999
2004	500	2 922	3 422
2005	500	4 178	4 678
2006	500	5 088	5 588
2007	500	5 809	6 309
2008	500	6 216	6 716

Source: VENCorp submission, 13 May 2002, p. 21.
Note: (a) Year ending 30 June.

Origin considered that there is considerable uncertainty surrounding local and regional temperature change trends, including the impact of various influences such as urban pollution and wind patterns on local climate.[457] On this basis, Origin did not accept that it is appropriate to include a warming trend in the demand forecast for the forthcoming access arrangement period. Origin suggested that the GasNet and VENCorp access arrangements should incorporate consistent demand forecasts. Further, Origin considered that GasNet would achieve 'asset over-recovery' if it included both a warming trend in the demand forecast and a higher asset beta based on exposure to volume risk.[458]

While acknowledging the difficulties attached to forecasting the impact of gas-fired power generation projects, Origin considered that 'the VENCorp and GasNet demand forecasting methodologies should be segmented into power plant demand and non-

457 Origin submission, 17 May 2002, p. 7.

458 ibid., p. 10.

power demand' which it considers would assist the understanding of system utilisation and the likely impact on tariffs.[459]

BHP Billiton commented that GasNet's forecasts 'omit the impact of Yolla introducing gas at Lang Lang, … of Minerva gas going to South Australia, and of TXU shipping gas to South Australia from Ion[a]'.[460] BHP Billiton also stated that GasNet has omitted zonal data on gas demand which it regards as necessary in order to demonstrate the appropriateness of zonal tariffs. BHP Billiton considered that GasNet should provide zonal data including MDQ and five and 10 day average maximum demand, and that the data should be compared to the actual capacity of the different zones.[461] Further, in the context of expected depletion rates for the Gippsland Basin gas reserves, BHP Billiton submitted that 'demand forecasts by ABARE and NIEIR (relied upon by GasNet) are too high'.[462]

BHP Billiton comments that the difference between the GasNet and VENCorp forecasts is less than 0.5 per cent and suggests GasNet can adjust tariffs through the K factor mechanism in response to disparities between forecast and achieved volumes. BHP Billiton suggests 'that a slight under estimation of forecast volume would be preferred to an over estimate' and that the Commission should ensure 'that any over recoveries resulting from poor gas volume forecasting are quickly returned to users'.[463]

ENERGEX commented that it tended to support VENCorp's analysis regarding warming associated with greenhouse and urban heat island effects. ENERGEX questioned GasNet's reliance on metropolitan weather station data and commented that urban and rural weather station data were unable to support GasNet's claim. Further, ENERGEX considered that 'even if the reduction suggested by GasNet were true, the effect would be "in the noise" of the other statistical uncertainties underpinning the forecast'.[464] ENERGEX concluded:

> On balance therefore, we suggest that the GasNet model provides little value and that energy flows over the period of the access regime should be referenced to VENCorp's annual forecast. Consistent with our earlier proposal for joint application by VENCorp and GasNet, we believe that the underlying assumptions for the treatment of the assets should be the same for both of the two businesses.[465]

ENERGEX stated its preference that VENCorp's forecasts be used for both access arrangements. However, it noted that the proposals being put forward by the Victorian distribution businesses appeared to be more consistent with the GasNet approach and encouraged overall uniformity of approach.[466]

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[459] ibid., pp. 7-8.

[460] BHP Billiton submission, 17 May 2002, p. 9.

[461] ibid., p. 10.

[462] ibid., p. 6.

[463] BHP Billiton submission, 21 June 2002, pp. 34-35.

[464] ENERGEX submission, 9 May 2002, p. 2.

[465] ibid., pp. 2-3.

[466] ibid., p. 8.

DEI recommended that consistent demand forecasts be required across the two access arrangements but did not specify a preference for either set of forecasts.[467] In addition, DEI stated that it considers that GasNet's forecast flows do not represent the most likely levels of production across the Victorian network. DEI considers that the forecasts significantly underestimate daily quantity flows for the VicHub facility while overestimating flows from Thylacine and Geographe (whose start-up date it considers may be outside the second access arrangement period). DEI also queried the forecast increase in La Trobe zone flows between 2001 and 2002 and suggested that an in-depth analysis of the demand forecasts is warranted.

AGL noted the difference between the two sets of forecasts and commented that 'the effect of a reduced load forecast coupled with a proposed increased capital base would tend to infer higher overall tariffs than would otherwise be the case'.[468]

7.1.5 Draft Decision

The Draft Decision noted that demand forecasts represent a critical element of any regulatory assessment under a building block approach like that applicable to GasNet's access arrangement. A service provider is subject to aggregate demand risk and will earn greater (less) than forecast revenue if actual demand is greater (less) than that forecast. As a result, a service provider has a strong incentive to exceed the forecasts. It may seek to achieve this by encouraging demand growth. It may also attempt to base its tariffs on conservative demand forecasts.

The Commission considered the views expressed by a number of parties that the aggregate demand forecasts for the second access arrangement period should be consistent across the two access arrangements and that the VENCorp forecasts should be preferred. It also considered views relating to likely supply capacities from different sources over the next five years and the potential impact on flows across segments of the PTS.

The Commission stated that it considers that the VENCorp Annual Planning Review forecasts have been determined through a transparent process involving public consultation and form a sound basis for the demand forecasts that will be used to derive the tariffs to apply for the second access arrangement period. It noted that the CSIRO report commissioned by GasNet supports a comparatively small adjustment to these estimates and that VENCorp considers that the differences between the estimates are not material when other factors are taken into account. It also noted that GasNet considers that no credible critique has been provided of the CSIRO report.

The Commission noted the comparatively small differences between the aggregate gas demand projections underpinning the proposed GasNet and VENCorp tariffs. It considered that that these forecasts should be consistent across the two access arrangements.

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467 DEI submission, 13 May 2002, p. 2.

468 AGL submission, 9 May 2002, p. 3.

The Commission proposed in its Draft Decision to accept GasNet's total demand forecasts for the PTS over the second access arrangement period. Accordingly, it proposed an amendment for the revised VENCorp access arrangement to ensure that consistent forecasts are used across the two access arrangements.

The Commission noted that the accuracy of GasNet's zonal and customer class demand forecasts is also important as these feed directly into the tariff formulation. Customers in a zone or class (Tariff D or V) will be charged too much (little) if relevant future flows are under (over) estimated and GasNet will achieve more (less) than the expected revenue. However, the K factor adjustment can compensate for divergences in product mix. The Commission acknowledges the difficulty in accurately forecasting zonal and customer class flows, especially given the uncertainty attached to supply developments. Generally, it does not consider it appropriate to attempt to 'micro-manage' forecasts at this level. It also stated that it considers it reasonable for GasNet to enjoy some insulation from zonal demand risk.

The Commission carefully assessed GasNet's zonal demand forecasts (provided in Table 7.2) for the Draft Decision, as well as the comments of interested parties on likely flows during the second access arrangement period (including VENCorp's projections for exports to NSW and the UGS facility (Table 7.5)). The Commission also examined expected demand over assets such as the Southwest Pipeline which GasNet proposes to include in the capital base (see chapter 4). As a consequence, changes were proposed to GasNet's injection forecasts. The Commission concluded that forecast flows from the Yolla field should be included from 2004. It stated that it expects that full production (20 PJ/year) will commence in early September 2004. Accordingly, the Draft Decision included a proposed amendment to GasNet's revised access arrangement.

The Commission also took into consideration a range of other issues raised in submissions. For example, it noted BHP Billiton's suggestion that GasNet's K factor mechanism can satisfactorily accommodate divergences from forecast demand. Similarly, it noted TXU's concerns that GasNet's proposed price control formula would allow GasNet the opportunity to earn more than its revenue requirement for reasons outside its control.[469] On this point the Commission noted that the K factor mechanism provides compensation for product mix variations but not for differences in aggregate demand.

The Commission's Draft Decision notes the difficulty in accurately forecasting zonal demand. While some parties have commented on individual aspects of GasNet's zonal forecasts, no overall alternatives have been proposed. The Commission stated that it does not have the expertise to propose alternative zonal forecasts. Accordingly, it proposed to accept GasNet's zonal forecasts as being reasonable.

469 TXU submission, 31 May 2002, p. 34.

7.1.6 Response to Draft Decision

In response to the Draft Decision, GasNet:

- accepted the amendment proposed in the Draft Decision to include flows from the Yolla field in its injection forecasts;
- expressed concern 'that there may have been a shift in the weather in Victoria' that would lead to lower annual demand;
- proposed a reassessment of weather patterns in 2004, and if warranted, an adjustment to the forecast volumes for 2005 to 2007; and
- stated that it had now identified a warming trend in the top 10 days which is consistent in percentage terms with the trend in annual EDD and that it proposes to amend the forecast of the top 10 peak days.[470]

In response to the Commission's GasNet and VENCorp draft decisions, VENCorp stated that its earlier comments about materiality had not been intended to indicate acceptance of the methodology proposed by GasNet for forecasting loads.[471] It considered that no clear case has been established to factor the urban warming trend recorded in the Melbourne CBD into demand forecasts outside the metropolitan area.[472] VENCorp's detailed assessment is provided in an appendix to its submission.[473] VENCorp considered that the information in the CSIRO report provided by GasNet was incorrectly applied and that the methodology used to derive tariffs would be incorrect. Nonetheless, as VENCorp considered that use of the GasNet forecasts will have minimal impact on the setting of its tariffs for the second access arrangement period, it accepted the Commission's proposed use of these forecasts.

7.1.7 Final Decision

Table 7.6 below demonstrates that gas demand forecasts accepted for the initial access arrangement period proved considerably optimistic. However, it needs to be noted that the calculated shortfall is approximately 4 PJ a year too high as the forecasts accepted in 1998 included demand on the WTS which is not included in the achieved figures. Nonetheless, GasNet has suffered considerable demand shortfalls and has been unable to earn the anticipated benchmark revenue.

[470] GasNet submission, 20 September 2002, pp. 35-36.

[471] VENCorp submission, 13 September 2002, pp. 7-8.

[472] ibid., p. 9.

[473] ibid., Appendix 1.

Table 7.6: Annual demand, 1998 to 2002

	PJ				
	1998	**1999**	**2000**	**2001**	**2002**
Forecast in 1998 (PTS and WTS)	205	212	216	223	227
Achieved – injections (PTS)	189	193	206	205	na
Shortfall - injections[a]	16	19	10	18	na
Achieved – withdrawals (PTS)	188	192	206	206	na
Shortfall - withdrawals[a]	18	20	10	17	na

Source: TPA access arrangement information, 30 November 1998, p. 28; VENCorp System Demand Data, 1982 – July 02, http://www.vencorp.com.au/.

Note: (a) The shortfall is overstated by approximately 4 PJ/year as the forecast demand includes volumes for both the PTS and WTS whereas the achieved data relate only to the PTS.

The forecasts provided by both GasNet and VENCorp with respect to the second access arrangement period recognise an enhanced warming trend that leads to proportionately lower demand projections for the second access arrangement period.

The forecasts provided by GasNet (and accepted by VENCorp) with respect to the second access arrangement period recognise an enhanced warming trend that leads to a step change in the demand forecasts which is illustrated in Table 7.7 below. The Commission estimates that the size of this change is approximately 14 PJ.[474]

Table 7.7: Annual demand forecasts, 1998 to 2007

PJ									
1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
205	212	216	223	227	216	225	233	237	241

Source: TPA access arrangement information, 30 November 1998, p. 28; GasNet access arrangement information, 27 March 2002, p. 15.

On 16 September 2002, VENCorp submitted amended revisions to its access arrangement that comply with the proposed amendments. Accordingly, the Commission has issued a Final Decision that approves VENCorp's amended revisions that incorporate demand forecasts consistent with those proposed by GasNet.

The Commission noted in its Draft Decision that the ESC had proposed to accept demand projections for the three Victorian gas distribution businesses' access arrangements which are consistent with GasNet's approach.[475] However, the ESC decided in its final decision that the VENCorp forecasts are more appropriate.

The Commission acknowledges that, as a result, the volume forecasts used for the gas transmission businesses vary from the forecasts used for the gas distributors. As previously noted, the variation is slight. The Commission has discussed this issue with

[474] Annual demand figures were estimated for 2003 to 2007 by using linear regression on the early forecasts. These estimates are on average 13.6 PJ higher than GasNet's forecasts.

[475] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 132.

the ESC and both regulators are of the view that the variation would be unlikely to have any material impact.

The Commission notes the suggestion by Origin that GasNet would achieve 'asset over-recovery' if it included both a warming trend in the demand forecast and a higher asset beta based on exposure to volume risk. While the appropriate value for the asset beta is considered in chapter 5, it is useful to examine the extent to which GasNet is exposed to volume risk in the context of the demand forecasts that will apply for the second access arrangement period.

It was noted that GasNet's volumes have been significantly lower than those forecast, resulting in a revenue shortfall for the first access arrangement period that GasNet expected to exceed $19.3 million. This shortfall supports the view that GasNet was exposed to substantial volume risk over the first access arrangement period. However, it is the demand forecasts for the second access arrangement period that are relevant to the current assessment. These have been based on a revised assessment by VENCorp of long term temperature trends (with further adjustment by GasNet) that results in GasNet's tariffs being set on the basis of considerably lower demand than would have been the case under the trend previously used.[476]

Estimates derived by the Commission indicate that demand outcomes for the first access arrangement period are consistent with the temperature trend factored into forecasts for the second access arrangement period. This suggests that revenue 'lost' during the first period reflects errors in forecasting rather than demand volatility. This loss would not be expected to recur following recognition of the temperature trend.

The Commission has decided to confirm its proposal in its Draft Decision to accept the demand forecasts included in GasNet's submission of 27 March 2002. While not discussed explicitly in the Draft Decision, the Commission has had to weigh the competing factors of section 2.24 of the Code in coming to its decision on this issue. Among other relevant factors, the Commission has had to balance the interests of users and prospective users against the legitimate business interests of the service provider.

The Commission does not consider it appropriate to accept at this stage a modification to VENCorp's peak demand forecasts (as suggested by GasNet in its response to the Draft Decision). Interested parties have not had the opportunity to respond to these proposals and would have a legitimate expectation that previously proposed forecasts would be adopted by the Commission. As noted earlier, GasNet stated when lodging its revisions that it 'currently accepts the forecasts provided by VENCorp without modification'.[477] The Commission acknowledges that GasNet may seek an early review of its revised access arrangement if it has sufficient evidence to support its contention that a further warming trend in terms of 10 peak days needs to be accommodated.

The Draft Decision proposed that GasNet include forecast flows from the Yolla field in its flow assumptions from 2004. GasNet has indicated to the Commission that it

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[476] It was estimated earlier that the annual demand figures for 2003 to 2007 would have been approximately 13.6 PJ higher if the earlier trend was used. GasNet's adjustment accounts for no more than 1.3 PJ of this difference (in 2007).

[477] GasNet submission, 27 March 2002, p. 106.

accepts this proposed amendment. No other comments have received on this matter. The Commission has concluded that the proposal in the Draft Decision remains appropriate. Accordingly, an amendment is required.

Amendment 32

GasNet must amend section 4 of its revised access arrangement information to include forecast flows from the Yolla field in its flow assumptions from 2004.

7.2 Forecast revenue

7.2.1 Code requirements

As noted previously, the Code sets out (section 8.4) three alternative methodologies for determining total revenue: Cost of Service, IRR and NPV.

7.2.2 Current access arrangement provisions

GasNet's predecessor used a Cost of Service methodology for the initial access arrangement period. Table 7.8 shows the benchmark revenue for the first access arrangement period which was calculated as the return on the value of the capital base and working capital plus depreciation of the capital base plus the operating and maintenance costs incurred in providing its services over the covered pipeline.

Table 7.8: Benchmark revenue, 1998 to 2002

	$ million				
	1998	**1999**	**2000**	**2001**	**2002**
Return on assets	28.8	29.6	30.8	31.8	31.6
Depreciation	12.3	13.1	14.0	14.9	15.0
Return on working capital	0.7	0.6	0.6	0.7	0.7
Operations and maintenance	19.3	19.4	19.1	18.7	18.8
Total	61.1	62.7	64.5	66.1	66.0

Source: TPA access arrangement information, 30 November 1998, p. 17.

7.2.3 GasNet proposal

GasNet proposes to continue to use the Cost of Service methodology. Its proposed revenue and its constituents are shown in Table 7.9 below. A CPI-X price path giving the same NPV as the forecast revenue requirement is proposed in order to achieve a smooth tariff path. The revenue requirement and the benchmark revenue for the second access arrangement period are also shown.

Table 7.9: Proposed revenue, 2003 to 2007

	$ million				
	2003	**2004**	**2005**	**2006**	**2007**
Return on assets	45.73	45.62	45.72	46.02	46.17
Depreciation	19.28	20.04	21.16	21.91	22.16
Non-capital costs	42.91	23.69	23.43	25.25	25.66
Total revenue	107.92	89.35	90.31	93.18	93.99
Benchmark revenue	93.92	94.96	96.11	96.53	96.67

Source: GasNet submission, 27 March 2002, p. 104.

7.2.4 Submissions to Issues Paper

No material issues were raised in submissions about the composition of GasNet's revenue requirement for the second access arrangement period.

7.2.5 Draft Decision

The Commission noted that it considers that GasNet's proposal to maintain the Cost of Service approach and to utilise tariff smoothing is appropriate. However, as discussed elsewhere in the Draft Decision, a number of changes were required to GasNet's benchmark revenue assumptions. On average, the nominal annual revenue for the second access arrangement period was estimated to be approximately $75.5 million if the proposed amendments were implemented.

7.2.6 Response to Draft Decision

A number of parties referred to aspects relating to specific revenue components. These are discussed in the relevant sections of this Final Decision.

7.2.7 Final Decision

The Commission notes that a number of factors need to be considered when comparing the regulatory revenues for the second access arrangement period with the amounts shown in Table 7.8 for the first period:

- GasNet underperformed the forecasts for 1998 to 2002 by an estimated $19.3 million due to lower than forecast demand. Consequently, the forecasts overstate GasNet's achieved performance. Approximately $12.9 million of this is included as K factor recovery in the second period;
- GasNet's tariffs and benchmark revenues increased by approximately 10 per cent in 2000 as a result of including the Interconnect Assets in the RAB (which is not shown in Table 7.8); and
- GasNet has been earning substantial unregulated revenues since 1 October 2000 under five year take-or-pay contracts with the three foundation retailers totalling 100 TJ/day for use of the Southwest Pipeline. GasNet appears to be earning further unregulated revenues as only 60.6 TJ/day of capacity on that pipeline is currently not reserved (of a total capacity of approximately 260 TJ/day), however, the

Commission understands that details of these arrangements are not publicly available.[478] Consequently, the forecasts in Table 7.8 understate GasNet's achieved performance when both regulated and unregulated gas transmission revenues are considered. These unregulated revenues will cease at the end of 2002 and will be replaced by regulated revenues.

Table 7.10 below summarises GasNet's (unsmoothed) regulatory revenue over the second access arrangement period consequent to its proposals and the amendments required by the Commission.[479] On average, the nominal annual benchmark revenue for the second access arrangement period is expected to be approximately $77.0 million.

Table 7.10: Approved regulatory revenue, 2003 to 2007

	$ million				
	2003	**2004**	**2005**	**2006**	**2007**
Return on capital	42.5	42.1	41.8	41.8	41.9
Depreciation	7.5	8.4	9.4	9.9	9.8
Normalisation	2.2	2.3	2.5	2.8	3.0
Equity raising costs	0.4	0.4	0.4	0.4	0.4
Operations and maintenance	19.3	19.9	19.5	21.2	21.5
Return on 'working capital'	0.1	0.1	0.1	0.1	0.1
K factor carry forward	12.9				
Total revenue	84.9	73.2	73.7	76.2	76.7

Source: ACCC analysis.

478 VENCorp Public Register of Spare Capacity for the Gas Transmission System, http://www.vencorp.com.au/.

479 Some minor adjustments to these amounts may be required as a result of further enhancements to the financial models.

8. Reference tariffs

8.1 Cost allocation and tariff structure

8.1.1 Code requirements

Section 8.38 of the Code requires that reference tariffs should to the maximum extent that is commercially and technically reasonable recover costs directly attributable to the reference service and a fair and reasonable share of joint costs while meeting the objectives of section 8.1 of the Code. Section 8.42 requires that recovery of a particular user's contribution to revenue also follows these principles. In addition, the Code requires the regulator to take into account the service provider's legitimate business interests, the interests of users, the public interest and the other items identified in section 2.24.

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 raising tariffs to 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.

8.1.2 Current access arrangement provisions

Under the provisions of GasNet's access arrangements, all costs of a direct capital nature (return on capital and depreciation) are allocated to each of the 24 asset groups on the basis of the ORC of the assets in each group. Locational O&M costs are allocated to asset groups on the basis of pipeline length. The costs for each asset group are allocated to off-take points within that group based on usage and the length of pipe used. Costs of an indirect nature (that is, non-locational O&M, return on and depreciation of corporate headquarters buildings) are allocated on a postage stamp basis (a set amount per gigajoule transported).

For pricing, the off-take points are amalgamated into eight pricing zones. Costs are recovered through three tariffs: an injection charge on the five peak injection days; a peak withdrawal charge on the five peak withdrawal days; and an anytime withdrawal charge on the total volumes throughout the year. Some tariffs are reduced for users upstream of the notional hub at Pakenham to reflect the fact that they do not use all of the injection pipeline.

The direct costs associated with the injection pipeline are recovered by the injection tariff. The direct costs associated with the withdrawal zones are recovered by the peak withdrawal tariff. The costs recovered by these two peak charges are 65 per cent of total costs. The locational O&M and the indirect costs are recovered by the anytime withdrawal tariff.

8.1.3 GasNet proposal

GasNet proposes to abolish the current peak withdrawal tariff and simply continue to charge an injection tariff based on peak usage and a withdrawal tariff based on annual usage. GasNet states that while users have concerns over the operation of the peak withdrawal tariff 'no concerns have arisen with respect to the use of peak day injection tariffs, or with the extent and coverage of the tariff zones'.[480] GasNet proposes that the new structure would be re-assessed at the next scheduled access arrangement revision.[481] GasNet also proposes to add to the current tariff classes (Tariff D and Tariff V) a new class of Refill tariff for storage which would be charged at marginal cost (which is the cost of compressor fuel at the appropriate compressor station).[482]

Under GasNet's proposal, direct capital costs (return on capital and depreciation) associated with pipeline, regulator and compressor assets are apportioned among the 27 pipeline segments according to the ORC of each asset. Direct operating costs are allocated to these segments according to pipeline length (in the first access arrangement period they were allocated only to withdrawal pipes). There are two major exceptions to this method. First, the costs (capital costs and incremental operating costs) associated with the Southwest Pipeline are allocated directly to that asset. Second, the majority of the Interconnect costs are allocated on a postage stamp basis (see below) while the remaining costs of the Interconnect (eight per cent of the total) are allocated directly to that asset.

The remaining costs are the indirect costs and consist of the capital costs of non-system assets, general and administrative O&M, return on working capital, benefit sharing allowance, recovery of unrecovered K factor balance, asymmetric risks and capital raising costs, as well as the majority of the Interconnect costs rolled in under the system-wide benefits test. These costs are allocated on a 'postage stamp' basis: that is, each gigajoule transported is allocated the same cost, irrespective of where it enters and leaves the system.

Costs associated with injection pipes will be recovered by the peak injection charge. A separate injection charge applies to each injection point and is based on the 10 peak days usage at the relevant injection point. Injection costs account for 27 per cent of total costs.

The costs for each pipeline segment, other than for injection pipeline assets, are then allocated to each off-take point within the pipeline segment (and to gas flowing through the segment) on the basis of usage and distances flowed.[483] GasNet proposes, for the complete PTS, that usage be determined by forecast peak usage (which is now defined as 1 in 2 winter peak flows rather than the 1 in 20 winter peak flows used in the first access arrangement period) for the allocation of 60 per cent of the costs and by anytime usage for the other 40 per cent of the costs. It proposes that the costs associated with

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[480] GasNet submission, 27 March 2002, schedule 5, p. 36.

[481] ibid., p. 47.

[482] ibid., p. 51.

[483] To work this out, one needs to determine the direction of forecast flows. The injection point for each off-take is determined by allocating forecast injection volumes to the off-takes nearest the injection point until all forecast volumes are allocated.

injection pipelines be allocated 100 per cent by peak usage (as the tariff will be a peak tariff) and that the remaining costs, associated with the withdrawal zones, be allocated 45 per cent by peak usage and 55 per cent by annual usage to each off-take. Thus a total of 60 per cent of costs will be allocated by peak volumes.[484]

The total costs applicable to users at an off-take will be the costs calculated above plus the appropriate proportion of the costs calculated for gas passing through all other segments on the physical path from the injection point to the off-take point. Finally, the costs associated with all the off-takes in each price zone are added together and divided by the annual usage to derive the withdrawal anytime tariff. GasNet proposes to divide users into 15 price zones, an increase over the current 12.[485] Throughout this process the costs applicable to Tariff V and Tariff D customers are isolated so that separate tariffs are calculated.

The above cost allocation and tariff structure mean that while 60 per cent (compared with 65 per cent in the first access arrangement period) of costs are <u>allocated</u> to users on the basis of peak volumes, only 27 per cent of costs (compared with 65 per cent in the current access arrangement period) are <u>recovered</u> through peak charges.

GasNet has proposed several refinements to the general approach described above. Consistent with the access arrangement as it currently stands, GasNet proposes lower injection tariffs for zones close to Longford (which do not use the full injection pipeline). GasNet is proposing a similar approach for matched withdrawals close to other injection points.

GasNet also proposes that withdrawal tariffs in the northern zones (North Hume, Wodonga and Murray Valley) be reduced for gas injected through the Interconnect to reflect the smaller portion of the system used. Further, several points on the system have been identified where GasNet considers it would be prudent to offer a discount (to avoid creating a bypass opportunity).

8.1.4 Submissions to Issues Paper

Some submissions strongly supported the removal of the peak withdrawal tariff and call for the removal of the peak injection charge. The main argument for this position was that users are unresponsive to price signals and the result would be administratively easier.[486] Other submissions stated that the peak withdrawal charge

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484 27% + 45% of (100%-27%).

485 As noted above, the access arrangement currently divides users into eight zones. A ninth zone was defined (in the west Gippsland area) but it did not contain any users. The Murray Valley Pipeline was not considered a zone as users on it had to pay the tariff for the North Hume zone as well as an incremental tariff for the Murray Valley Pipeline. The Murray Valley Pipeline is now considered a separate zone. Since 1998, the Interconnect and the Southwest Pipeline have both been added to the system and each of these is considered to constitute a separate zone. Consequently, while eight zones were noted in the first access arrangement period, the 15 zones now proposed are a result of adding three new zones to the 12 current at the end of 2002.

486 ENERGEX submission, 9 May 2002, p. 4; AGL submission, 9 May 2002, p. 1; TXU submission, 31 May 2002, pp. 17, 19 and 22.

should be retained to give appropriate price signals to users.[487] BHP Billiton stated that the GasNet system is designed to accommodate peak winter demand and therefore a high proportion of revenue should come from these maximum demand requirements. It was argued that allocating costs on annual flows does not send the appropriate signals to users to reduce demand at times of constraint and is not cost reflective.[488] However EnergyAdvice, in its argument for peak price signals, also acknowledged that these signals have limited ability to alter behaviour. It stated '[t]he incentive for end users to try to avoid system peak withdrawal days has significantly diminished with the tariff redesign, however we are unaware of end users actively seeking to avoid these costs under the current tariffs'.[489]

Some submissions opposed the allocation of costs on a postage stamp basis. BHP Billiton, Amcor and PaperlinX regarded a more appropriate basis of allocation to be MDQ or number of transactions (for general and administrative), diameter-length of pipeline (for working capital) and a K factor redistribution towards those assets not returning the anticipated share of expected revenue.[490]

Several submissions commented on the allocation of the under-recovered K factor amount. BHP Billiton maintained that future benefits and K factor under-recoveries need to be allocated to where they are generated but also that the postage stamped costs need to be allocated to discrete elements (such as the Southwest Pipeline and WTS).[491] However, it also sought no cross-subsidisation between WTS, Southwest Pipeline and PTS including separation of the first two from the K factor calculations.[492] EUAA made similar points.[493]

BHP Billiton contended that the tariff structure must reflect the expectation that the Southwest Pipeline will be an under-utilised resource in the second access arrangement period.[494]

DEI expressed concern with the definition of 'shipper' which could exclude some activity from being treated as matched withdrawals when it is more appropriate that they be so.[495]

AGL pointed to what it considers to be an inconsistency in the Culcairn withdrawal charge.[496]

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487 Amcor and PaperlinX submission, 24 June 2002, pp. 16-17; Origin submission, 17 May 2002, p. 9; EnergyAdvice submission, 30 May 2002, pp. 3-4.

488 BHP Billiton submission, 21 June 2002, p. 17.

489 EnergyAdvice submission, 30 May 2002, p. 5.

490 BHP Billiton submission, 21 June 2002, pp. 13, 19 and 36; Amcor and PaperlinX submission, 24 June 2002, pp. 18-19.

491 BHP Billiton submission, 21 June 2002, p. 11.

492 ibid., p. 10.

493 EUAA submission, 11 July 2002, pp. 6 and 10.

494 BHP Billiton submission, 21 June 2002, p. 12.

495 DEI submission, 13 May 2002, p. 3.

496 AGL submission, 9 May 2002, p. 2. As the Commission understands GasNet's proposal, no exports to NSW are forecast. Consequently, the costs allocated to the Interconnect are recovered by the

EnergyAdvice suggested that if users responded to the new price signals by undervaluing demand management then the supply side could become prematurely stressed requiring additional investment and thus higher tariffs.[497]

TXU considered that the proposed tariffs are very complex, are likely to distort investment decisions and are not efficient.[498] TXU called for a reduction in the number of zones to reduce complexity and reduce rural and urban price differentials.[499] TXU was very concerned that all charges (specifically the injection charge) cannot be allocated to specific customers.[500] TXU appeared to advocate charges being standardised between users.

TXU noted that the VENCorp planning review says there is unlikely to be major congestion in the next five years, and questioned the peak pricing approach.[501]

Amcor and PaperlinX opposed the proposed allocation of costs on a postage stamp basis on the grounds that it would disadvantage users with a flat load.[502]

VENCorp and ENERGEX submitted that GasNet and not VENCorp should be responsible for offering prudent discounts.[503] However, ENERGEX was not convinced that customers generally should finance the prudent discounts that GasNet is proposing.[504] No reason was given for this view.

8.1.5 Draft Decision

The Draft Decision noted that much of the proposed tariff structure and cost allocation is essentially unchanged from that approved by the Commission in 1998. At that time the Commission was satisfied that the cost allocation methodology was appropriate and that tariffs would recover a fair and reasonable share of costs from each user.[505] The Commission's assessment in the Draft Decision was that this general structure continues to be appropriate for the reasons indicated in the 1998 Final Decision. It noted that GasNet undertook a public consultation process in 2001 which considered

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injection tariff for the Interconnect which is based on the volumes forecast to flow south along it. The withdrawal tariffs for the northern zones are calculated based on these zones being supplied from Longford, but with no export volumes being included in the calculation. In the event that some volumes are exported, GasNet has developed a tariff by calculating the North Hume withdrawal tariff as before but including 3PJ of export volumes as well. This produces a lower withdrawal tariff for exports (reflecting the fact that if they occur then the tariff should be lower to reflect the greater volumes flowing). There would be no Interconnect injection tariff charged on these exports. The Commission does not understand what AGL considers inconsistent in this approach.

497 EnergyAdvice submission, 30 May 2002, p. 5.

498 TXU submission, 31 May 2002, pp. 16-17.

499 ibid., p. 19.

500 ibid., p. 22.

501 TXU submission, 31 May 2002, p. 23.

502 Amcor and PaperlinX submission, 24 June 2002, p. 17.

503 VENCorp submission, 13 May 2002, p. 7; ENERGEX submission, 9 May 2002, p. 2.

504 ENERGEX submission, 9 May 2002, p. 2.

505 ACCC, 1998 Final Decision, p. 91.

users' tariff preferences. The Draft Decision concentrated on those elements of the GasNet proposal which differ from the arrangements currently in place.

The key proposed changes which prompted concern from the Commission and/or were raised in submissions were:

- the increased complexity of the tariffs (with consequent concerns by some parties that GasNet may be able to over-recover costs in some instances);
- the removal of the peak withdrawal tariff and the change in relativities between peak and anytime tariffs;
- the allocation of direct O&M to injection pipelines;
- the allocation of the unrecovered K factor adjustment, GasNet's share of the efficiency benefits from the first period and the capital raising costs by the postage stamp method;
- the introduction of a cross-system withdrawal tariff; and
- an increased number of matched withdrawal tariffs and the introduction of prudent discounts.

In the 1998 Final Decision, the Commission accepted the proposed proportion of revenue to be recovered by the peak and anytime charges (67:33 per cent), noting that there was no theoretically correct proportion (as recovery of total costs necessitated charging at above marginal cost). The Commission foreshadowed that it would revisit the issue at the end of the first access arrangement period.[506] Also in that Final Decision, the Commission noted the dependence of the derived tariffs on the assumptions in the modelling on the assumed source of gas. It indicated that the review in 2002 would be a more appropriate time in which to take sourcing into account for the annual tariff calculation.[507]

Overall complexity

The Draft Decision noted that cost allocation and tariff structure design for pipelines will generally be expected to involve a number of trade-offs. Considerable complexity may be required to achieve a high level of cost-reflectivity but this may result in needlessly high costs. This is recognised in the Code (sections 8.38 and 8.42) which requires cost-reflectivity to be maximised subject to the constraint of it being technically and commercially reasonable.

In responding to comments by parties favouring greater equalisation of charges and simpler tariffs, GasNet noted that it is constrained by the requirements in the Code for efficient cost allocation.[508]

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[506] ibid., p. 85. The peak:anytime ratio of 67:33 was for 1998. It was noted that it would increase to 70:30 in 2002. As noted in section 8.1.3, GasNet refers to the split in the first access arrangement period as 65:35.

[507] ibid., p. 88.

[508] GasNet response to submissions, 12 June 2002, p. 10.

In considering these tensions, the Commission was aware that individual users and end-users may be comparatively advantaged or disadvantaged by a particular approach. For example, merging of tariff zones would have the effect of averaging charges that would otherwise differ. Similarly, different tariff designs can impact significantly on the charges which would be paid by customers with different usage patterns.

GasNet proposed to remove the peak withdrawal tariff but to add extra matched withdrawal tariffs, prudent discounts, a transmission refill tariff, a cross-system withdrawal tariff, three extra pricing zones and more injection points. Some parties regarded this complexity as unnecessary. Further, some considered that certain features of the proposed tariff structure would allow GasNet to over-recover the benchmark revenue. The Commission considered an example provided by TXU to demonstrate potential over-recovery.[509] However, the Commission's assessment was that GasNet would not over-recover in this case as the K factor adjustment at the end of the year would lower the tariffs applicable in the following year.

While the K factor mechanism has been in effect since 1999, comments in several submissions suggest that not all interested parties fully understood its operation. Importantly, the Draft Decision noted that GasNet's access arrangement contains (and it is proposed that it will continue to contain) an average revenue (not total revenue) control. Any differences between the total volume actually demanded, and that forecast, will be borne by GasNet. Any changes in the product mix (for example, the relativities between zones or customer classes) are borne by users. Any under-recovery or over-recovery of average revenue, because of changes in product mix, is corrected by the K factor adjustment to future tariffs. The average revenue control therefore does not allow for the potential over-recovery that concerns some interested parties.

The Commission considered concerns about the complexity of the proposed tariffs. It recognised that there are more elements to the tariff structure, requiring a significant and detailed assessment of the proposed tariff structure. However, the Commission concluded in the Draft Decision that it was not persuaded that this complexity would hinder the operation of the market to the extent that the structure should be rejected. The appropriateness of each element is assessed below.

Peak and non-peak relativities

As noted in the Draft Decision, while GasNet proposed that 60 per cent (65 per cent in the first access arrangement period) of costs be <u>allocated</u> to users on the basis of peak volumes, it proposed only 27 per cent of costs (65 per cent in the first access arrangement period) be <u>recovered</u> through peak charges. The Commission noted in the Draft Decision that this is a major difference in the way in which revenues are collected from users. The effect on individual customers is that the higher a customer's load factor, the greater will be the increase in average tariffs compared to customers with low load factors. That is, customers with high load factors will now contribute to the recovery of costs more than they used to, compared to customers with low load factors, and thus the differential between the tariffs paid by high load and low load users is reduced. A customer's load factor will be reflected in its injection charge and whether it is a Tariff V or a Tariff D customer (the load factors of these two user groups

[509] TXU submission, 31 May 2002, pp. 24-25. See also AGL submission, 9 May 2002, p. 2.

determine, in part, the differential between the two withdrawal charges).[510] The Commission noted that this may diminish the incentive customers have to manage their load. The peak charge is a price signal about the cost of congestion and that would be removed in part (it would still exist in the injection tariff).

GasNet asserted that most laterals are low volume and unconstrained and that with more gas being supplied at injection points other than Longford there are no constraints within the hub.[511] The Commission observed that on this basis it would be inappropriate for these parts of the system to be priced based on peak flows. However, if there is little likelihood of these pipes being constrained, it could be argued that no peak signal at all is appropriate (and consequently that there should be one withdrawal tariff for Tariff V and Tariff D customers). GasNet recognised this argument but proposed that some pricing according to peak usage should remain so that peaky and non-peaky customers do not experience a significant change in relative tariffs.[512]

The Draft Decision noted that there are many alternatives available to GasNet for the pricing of its services. Broadly speaking, apart from that proposed by GasNet, two were suggested by interested parties. One was that the peak withdrawal charge be maintained and the other was that the peak injection tariff be removed. The first option is essentially that the current tariff structure be maintained. The alternative is that all peak pricing signals be removed, which is essentially a view that there be one common anytime tariff.

The Commission considered these two options, as well as GasNet's proposal, mainly turned on the primary question of whether there should be peak pricing signals. This turned on two associated questions: is there (or is there likely to be) constraint on the system; and will users respond to the possible price signals available?

On the question of system constraints, GasNet stated that there are no constraints on the system at present and, if there are to be any constraints, they are likely to occur on the injection pipelines and not the rest of the system.[513] However, the Commission noted some factors which indicated that the pipelines more likely to face constraint could be withdrawal rather than injection pipelines. The discussion in the Draft Decision provided reasons for believing that the pipelines could be constrained in the next access arrangement period and also reasons why they may not. It appeared to the Commission that a reasonable case could be made for either scenario.

The Commission concluded that it was not convinced that congestion was likely in the next access arrangement period. However, it considered congestion was possible in the access arrangement period starting 2008, raising the need for users to face stable tariff structures. It would be unnecessarily disruptive for all peak signals to be removed for the second period only to be reintroduced in the third period. The Commission also

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510 The other factor that determines the difference between the Tariff V and Tariff D withdrawal tariffs for a particular zone will be the location of users (the average distance from the start of the zone).

511 As well as the access arrangement information and accompanying submission, GasNet repeated this claim in its response to submissions, 12 June 2002, pp. 10-11.

512 GasNet submission, 27 March 2002, schedule 5, p. 42.

513 GasNet response to submissions, 12 June 2002, pp. 10-11.

noted that peak signals are appropriate before congestion occurs: they are not only a tool for the allocation of capacity costs to those who constrain the system, they are also a tool to discourage users from producing the capacity constraint. In addition, the Commission considered that the evidence suggested that congestion is likely to occur on withdrawal pipes first, rather than injection pipes as GasNet has claimed.

On the question of users' and end-users' response to peak signals, while some submissions requested peak pricing signals to provide appropriate signals, they did not provide evidence that the signals have any effect. Other submissions indicated that users had not responded to the peak signals in the current tariff structure.

GasNet indicated that transmission charges account for only about 5 to 10 per cent of the final cost of delivered gas for the average user.[514] The Commission considered that for such a user, the motivation to alter behaviour in order to possibly avoid 65 per cent of transmission charges (or, as proposed, only 27 per cent of charges) is quite small. There are some users for whom transmission is a bigger component of the overall price (for example, users in high tariff zones who do not use any distribution system). However these users are only a small proportion of all users, and even for most of these users avoidable transmission costs under the current access arrangement are less than 16 per cent of delivered cost.[515] Thus, while for a few users the existence of peak tariffs would afford the opportunity to significantly reduce the delivered cost of gas, it was difficult for the Commission to see how the current provision of peak signals could produce a significant difference in usage. This analysis accorded with the observations on users' behaviour noted in the submissions mentioned above.

The Commission concluded in the Draft Decision that it was not convinced that a significant proportion of users respond to the current price signals. Consequently, it was less likely that the proposed (weaker) peak price signals would affect user behaviour.

The Draft Decision noted that while cost-reflective pricing and efficient pricing signals were of concern to the Commission, there were also other factors to be taken into consideration. Many users regarded the current tariffs as too complex, confusing and cumbersome. However, the most concern was in relation to the annual 'wash up'. This is an account settling process necessary because users pay peak charges each month to smooth out their payments. This necessitates charges based on forecasts until such time as actual usage on the peak days is known and the appropriate adjustment can be made. Users considered this process not only to be complex but also to multiply administrative difficulties in allocating costs to individual customers (especially contestable customers). It appeared to be for this reason that many interested parties advocated the abolition of all peak charges. In contrast, GasNet while acknowledging these issues, considered them to be largely connected with the peak withdrawal charge, claiming that it has received little complaint about the peak injection charge.

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514 ibid., schedule 5, p. 36.

515 The highest case scenario (except for the few users in the Murray Valley) is a Tariff D customer in North Hume where (for 2002) the anytime charge is 27 cents and the peak is 55 cents, assuming a load factor of 70 per cent. If it is assumed that gas costs $2.70 then the avoidable cost as a percentage of total cost is 15.7 per cent (55/(27+55+270)). Note that this analysis does not consider the VENCorp charges which would make the percentage of costs that are avoidable slightly less.

The Draft Decision concluded that the Commission did not find the evidence available to be particularly supportive of any of the three alternative tariff structures. Therefore, it proposed not to oppose GasNet's proposal to remove the peak withdrawal tariff but retain the peak injection tariff (which will recover 27 per cent of revenues).

Cost allocation

The Draft Decision noted that the main variation from the current provisions of the access arrangement was that GasNet proposed to allocate direct operating costs to both withdrawal and injection pipelines. At present the allocation is only to withdrawal pipelines. The Commission accepted this proposed change in its Draft Decision as being an appropriate allocation of these costs.

As noted above, some interested parties suggested that general and administrative costs would be better allocated on the basis of MDQ or the number of transactions. The Commission recognised that various parameters can be considered appropriate for each type of non-capital cost. However, as noted in the Commission's 1998 Final Decision, it considered that for simplicity, allocation of locational operating costs on the basis of pipeline length alone was a reasonable approach to cost allocation.[516] Similarly, while various parameters can be considered appropriate for the allocation of common costs, for simplicity, allocation on volume alone (the postage stamp approach) was considered reasonable. The only exceptions to this were costs which were not included in the common costs for the first access arrangement period. Their consideration in the Draft Decision is indicated below.

In the current cost allocation, locational and common operating costs are identified separately for the Western zone and charged to that system.[517] GasNet did not indicate that it proposed to continue this separation and the Western zone is allocated operating costs and other common costs (except for the rolled-in Interconnect costs) in the same way as other zones. The Commission considered this approach to be consistent with the integration of the WTS into the PTS.

Postage stamp allocation

The rationale for allocating costs on a postage stamp basis (a fixed amount per gigajoule transported, irrespective of the distance transported) is that the costs so allocated are costs incurred by users equally, irrespective of their physical location or other attributes (such as load factor). This approach was accepted by the Commission in 1998 for indirect costs (such as corporate office functions) and in the Draft Decision the Commission did not see any reason to change this approach for the next access arrangement period.

However, there are several new costs (or categories of costs) which GasNet proposed to be included in the tariff calculations and which it proposed to allocate on the postage stamp basis. The appropriateness of this approach needed to be assessed for each of these new cost categories.

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[516] ACCC, 1998 Final Decision, p. 84.

[517] ibid., p. 80.

As indicated in section 10.1.5 of the Draft Decision, the Commission did not consider it appropriate for GasNet to receive any additional revenue in the second access arrangement period on the basis of claimed efficiencies in operations and maintenance costs in the first period. Similarly, a return on working capital was not considered to be appropriate (see section 6.2.5 of the Draft Decision). Consequently, there was no need to consider the proposed cost allocation of these costs.

The Commission concluded that the allowance for asymmetric risks is appropriately allocated on a postage stamp basis as the benefits to users are not discernibly related to users' location. However, it was considered that this is not true of the amount for unrecovered K factor adjustment and capital raising costs.

The K factor adjustment has remained partly unrecovered because of the limitation on individual tariff increases in the first access arrangement period. Generally the K factor adjustment has been recovered by increasing each tariff by the same percentage amount (see section 6.2.2).[518] Consistent with this, the Commission considered that the K factor recovery should be allocated to all tariffs (except the tariff for the Southwest Pipeline) as a uniform percentage increase. The K factor adjustment should not be allocated to the Southwest Pipeline as it is not currently in the K factor calculations and therefore has not contributed to the unrecovered revenues.[519] An appropriate amendment was proposed in the Draft Decision.

Capital raising costs are costs linked to the level of capital required. The Commission considered it appropriate to allocate these costs on the same basis as other capital costs (which are apportioned over all system assets on the basis of their ORC). Consequently, an amendment was proposed in the Draft Decision.

Allocation by usage

Some submissions suggested that removal of the peak tariff is inappropriate as it could produce tariffs which are not cost reflective. However, the Draft Decision considered that cost-reflective tariffs result from the distribution of costs to users based on usage. The resulting tariffs will be cost-reflective whether the usage is defined as peak usage or annual usage. The choice of usage definition depends on what the tariff design is intended to achieve. As noted above, if there is congestion, a peak tariff may be appropriate (assuming it provides a price signal to which users are able to respond). Alternatively, if there is no congestion an annual tariff may be more appropriate.

Direct capital costs were allocated to users on the basis of peak usage in the initial access arrangement period. These costs are associated with the capacity of the system. These direct capital costs are 65 per cent of all costs. GasNet proposed for the second access arrangement period to allocate 60 per cent of total costs to users on a peak usage

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518 This is only approximately correct: the control would allow some tariffs to be set at a lower rate but only as long as those tariffs increasing at a faster rate (to maintain the average increase) did not increase by more than one percentage point above the increase in the average tariff.

519 As BHP Billiton appropriately noted, the K factor under-recovery should be allocated to those assets which generated it: BHP Billiton submission, 21 June 2002, p. 11. This approach of the Commission is contra to submissions which called for the Southwest Pipeline to be allocated some of the K factor under-recovery. See Amcor and PaperlinX submission, 24 June 2002, p. 10; BHP Billiton submission, 21 June 2002, p. 13; EUAA submission, 11 July 2002, p. 10.

basis. This reduction did not reflect a fall in direct capital costs. Rather, GasNet considered that signals relating to system capacity are at present of limited value as the system is not approaching constraint. GasNet considered that a larger reduction would result in an unnecessarily large tariff shock.[520]

As noted above, with 60 per cent of total costs allocated to users on a peak usage basis, if all injection costs (27 per cent of all costs) are allocated on this basis, 45 per cent (55 per cent in the current access arrangement period) of the withdrawal costs will also be allocated on the basis of peak usage.

In GasNet's proposal, allocation of costs to each off-take point within an asset zone (on the basis described in the paragraph above) occurs after costs are allocated to asset zones (see the discussion on cost allocation earlier in this section). It is this allocation procedure that helps create the difference between the tariffs for Tariff V and Tariff D customers within a zone. It will increase the tariff for Tariff V users (and lower the tariff for Tariff D users) because Tariff V users tend to have peakier demand.[521]

GasNet's proposal to allocate 45 per cent of withdrawal costs to peak usage (down from 55 per cent) will reduce these relativities. Whether this is appropriate depends on the questions discussed above on the issue of whether there should be peak charges: are there (potential) system constraints which should be signalled, and are users likely to respond to those signals? Alternative approaches would include maintaining the allocation at 55 per cent and for it to be completely based on annual usage.

The Draft Decision noted that the pricing signals produced by GasNet's proposed withdrawal tariffs will be much more muted than in the initial periods given the proposed removal of the peak withdrawal tariff. It is proposed that there would be two tariffs in each zone: for Tariff V and Tariff D (as there are now). However, the Commission noted that end-users are not able to respond to these signals resulting from tariff differentials between these two classes. Thus, it was questionable whether the differential between Tariff V and Tariff D serves any useful price signal.

The Commission noted that effective price signalling is not the only reason to maintain these relativities: each user's tariff is meant to reflect the costs associated with that user. However, the question then becomes: if there is no constraint, does the cost of a gigajoule shipped by users differ according to a user's load factor, or more correctly, according to whether they are Tariff V or Tariff D? On balance, the Draft Decision proposed not to oppose GasNet's proposal to allocate 45 per cent of withdrawal costs on the basis of peak usage.

Matched rebates

Matched rebates on injection tariffs were proposed for users who do not use all of the injection pipeline. These rebates currently apply to users in the La Trobe and Lurgi

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[520] GasNet submission, 27 March 2002, schedule 5, p. 42.

[521] The other contributor to the Tariff V:Tariff D differential is the location of customers within the zone. For example, if the majority of Tariff V customers are located close to the supply source of the zone and the majority of Tariff D customers are located near the end of the zone (and thus use more system assets) then in this case Tariff D tariffs will be higher and Tariff V tariffs lower.

zones whose gas is matched to injections at Longford. It was proposed that Tyers and West Gippsland would also be rebated for such injections. Similarly, matched injections were proposed for the Interconnect zone users who inject at Culcairn, and South West and Western zone users injecting at Port Campbell. The Commission considered it appropriate that the injection tariffs reflect the portion of the injection assets used by customers and did not object to the proposed matched rebates in the Draft Decision.

GasNet proposed to offer matched rebates on withdrawals from the North Hume, Murray Valley, Interconnect and Wodonga zones for gas injected at Culcairn in order to reflect the shorter transportation distance, that is, the lower use of the PTS, compared to gas sourced from Longford. Flows through the North Hume zone are relatively low resulting in a substantial increase in tariffs (for Longford sourced gas) in that zone and those zones further north: at least 50 per cent higher than current tariffs. GasNet considered that the tariffs are not genuinely cost-reflective because they will substantially exceed the long run marginal cost of supply to these zones. However, GasNet regarded tariffs that fall between marginal cost and stand-alone costs as efficient.[522] The Commission noted that the Code requires tariffs to recover any costs directly attributable to a service and a fair and reasonable share of joint costs. Any tariff between marginal cost and stand-alone costs can be considered to be free of cross subsidy. However, the Commission must consider whether the costs reflected by a particular tariff are appropriate or whether a different tariff would reflect a more appropriate allocation of costs.

GasNet stated that to the extent that they are above marginal cost, tariffs will send an inappropriate price signal and discourage gas consumption. However, the nature of the PTS assets is that most tariffs will be above marginal cost. If all tariffs were set at marginal cost, GasNet would not recover its required revenue. More appropriately, GasNet argued that adherence to its cost allocation model in this case will produce very high tariffs that will discourage gas flows to a greater extent than a marginal increase on the Metro zone (to the extent needed for the two approaches to be revenue neutral).

Consequently, GasNet proposed (for the four northern zones mentioned above) to calculate tariffs for Longford sourced gas on the assumption that all gas used in the northern zones is sourced from Longford, and to calculate tariffs for Culcairn sourced gas on the assumption that all gas used in the northern zones is sourced from Culcairn. This produced tariffs which it considered are more likely to encourage gas flows. The shortfall in revenue was proposed to be allocated to the Metro, Lurgi and Tyers zones and also to the Wodonga, North Hume and Murray Valley zones for gas injected at Culcairn in proportion to the direct operating costs allocated to those zones. In the Metro zone this was equivalent to an increase in tariffs of approximately 2 cents/GJ.

In summary, GasNet proposed to allocate some costs which its cost allocation model would normally allocate to the northern zones to other zones. The purpose is to produce tariffs in the northern zones which will not discourage gas transportation, and to recover the shortfall from zones in which a marginal increase in tariffs will not discourage gas transportation.

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522 GasNet submission, 27 March 2002, schedule 5, p. 44.

GasNet claimed that the delivered cost of gas in the northern zones, without the proposed adjustment, approaches the cost of alternative fuels, but does not give any evidence for this. It also claimed that the proposed tariffs are above the zones' marginal cost but again does not provide evidence. The Commission noted that no submissions from interested parties dealt with this issue.

The Commission must consider whether it is fair and reasonable for the majority of users, who are in the zones with low tariffs, to pay some of the costs attributable to users in the zones with high tariffs, in order for those users in the higher tariff zones to face tariffs which will encourage greater use of the system. In the Draft Decision the Commission concluded that there was insufficient evidence available to it at that time to indicate that the proposed modification would not satisfy the principles of the Code. Accordingly, the Commission proposed not to oppose GasNet's proposal.

In addition, GasNet proposed to offer a matched withdrawal tariff to customers who withdraw gas which is injected at Pakenham from three specific connection points in the Metro zone (near Pakenham). This proposal was effectively a prudent discount which was designed to counter a potential bypass opportunity. It was dealt with in the section on prudent discounts below.

The Draft Decision acknowledged GasNet's intention to prepare an amendment to the proposed revised access arrangement to allow a VicHub trader and a withdrawing retailer to confirm a matching arrangement.[523]

Cross-system tariff

As noted in the Draft Decision, the Lurgi, Tyers, La Trobe, West Gippsland and Southwest withdrawal zones have withdrawal tariffs which reflect the cost of gas transported from their nearest injection point. GasNet proposed that for these zones when gas is not sourced from the nearest injection point, an additional tariff should apply to reflect the additional use of the system.

The Commission understood the concept behind this tariff to be that the gas under question would contribute to the physical volumes flowing from the injection zone to the Metro zone. Contractually, and conceptually, this gas would flow further, although not physically. GasNet intended, therefore, to charge users an amount similar to the Metro withdrawal tariff to match the tariff to the use of the system. GasNet stated that the tariff 'will be the Metro zone tariff discounted for the indirect cost allocations (which are already recovered from the withdrawal zones)'.[524] TXU considered the tariff was likely to inhibit competitive market development because it adds to transportation costs.[525] However, if the tariff reflects appropriate cost allocation, which in this case the Commission considered it did, then market development should not be hindered.

The Commission noted that for gas flowing from Port Campbell to the La Trobe zone the proposed tariffs would not give a total withdrawal charge similar to the Metro tariff. This was because the La Trobe zone is discounted to avoid presenting a bypass

[523] GasNet response to submissions, 12 June 2002, p. 18.

[524] GasNet submission, 27 March 2002, schedule 5, p. 46.

[525] TXU submission, 31 May 2002, p. 21.

opportunity. It may have been more appropriate for there to be a different cross-system withdrawal tariff in this instance, so that the combined withdrawal tariffs equated the tariff for the Metro zone. However, the Commission noted that this would increase the complexity of the tariff structure and did not consider that the potential advantages would outweigh the cost of the added complexity. The Commission's Draft Decision therefore proposed to accept the cross-system withdrawal tariff as proposed by GasNet.

Some submissions indicated an anomaly with the cross-system tariff as it applies to the northern zones. GasNet responded that this tariff was not intended to apply to flows to the northern zones as the costs of transmission through the Metro zone are included in the northern withdrawal tariffs.[526] The Commission agreed with GasNet and considered this appropriate. The Commission noted that while in Schedule 1 of the access arrangement, section 1.5(c) may be ambiguous, section 1.5(d) appeared to clarify the situation.[527]

DEI and AGL expressed a concern that GasNet could over recover its revenue requirement through the operation of the cross system withdrawal tariff.[528] However, as noted in the discussion of overall complexity above, and by GasNet,[529] the K factor operation will not allow GasNet to over-recover revenues by virtue of the application of the cross-system withdrawal tariff.

TXU also considers that the cross-system tariff produces a pricing anomaly as it would be cheaper to transport Longford gas to the Southwest Pipeline withdrawal zone than it would be for Port Campbell gas.[530] The Commission noted that this would be the case if all the gas was supplied on peak days, which would appear to be an unlikely scenario as the peak days are not known in advance. If supplied all year, the Port Campbell sourced gas is transported more cheaply.[531]

Prudent discounts

GasNet proposed to introduce prudent discounts for:

- the withdrawal tariff at Wodonga for gas matched to injections at Culcairn;
- the withdrawal tariff at three withdrawal points within the Metro zone which are close to Pakenham for gas matched to injections at Pakenham;
- the withdrawal tariff at La Trobe; and
- the withdrawal tariff for Warrnambool and Koroit in the Western zone.

In all cases the prudent discount was targeted at existing users who have, or will have, the opportunity to completely bypass the PTS. In the absence of the discount the customers in question would not use the system.

526 GasNet response to submissions, 12 June 2002, p. 11.

527 GasNet access arrangement, 27 March 2002, pp. 21-22.

528 DEI submission, 13 May 2002, p. 3; AGL submission, 9 May 2002, p. 2.

529 GasNet response to submissions, 12 June 2002, p. 11.

530 TXU submission, 31 May 2002, p. 24.

531 19 cents/GJ from Port Campbell compared to 32 cents/GJ from Longford for a customer with 100 per cent load factor.

A number of interested parties expressed opposition to this proposal. They considered that the provision of a prudent discount for one customer (or group of customers) would result in other customers paying higher tariffs. The Commission considered that it may be that other customers will pay more than they did before the threat of bypass. However, according to the Code, a prudent discount is one which results in other users paying lower tariffs than they would in the absence of the discount (and consequently the absence of the user targeted by the discount).

The Commission evaluated the methodology used by GasNet to calculate the bypass tariffs. It agreed with the principles used and considered the input data appropriate. While it did not concur with all the assumptions and calculations made by GasNet, the differences between the Commission's preferred approach and that adopted by GasNet generally had little impact on the level of the tariffs calculated. In particular, the Commission's approach would not have had the effect of increasing the size of the discount that needed to be offered and therefore recovered from other users. Further, the Commission agreed with GasNet's assessment that in the absence of the prudent discounts there is a significant likelihood that the target users would cease to use the PTS. Consequently, the Commission proposed in the Draft Decision to accept the prudent discounts proposed for the second access arrangement period.

TXU considered the prudent discounts for users in Warrnambool and Koroit on the WTS should not be offered until the bypass threat is actual rather than perceived.[532] This prudent discount proposal was expressed in terms of it being initiated if 'either the SEA Gas Pipeline or the Southern Gas Pipeline has been commissioned'.[533] At the time of the Draft Decision there were two pipelines proposed.

The Commission acknowledged that either of these proposed pipelines might pose a bypass threat affecting parts of the WTS. This would depend on both the likely associated costs and the commercial strategies of the proponents. It was not clear from GasNet's proposal that introduction of a prudent discount should be triggered automatically by the commissioning of either pipeline without taking other factors into account. The Commission considered that evidence would be needed that a specific bypass threat is credible before prudent discount is triggered. Accordingly, the Commission proposed an amendment to require GasNet to provide sufficient evidence to establish that a bypass threat is credible.

Origin requested that the access arrangement have the flexibility to allow for future prudent discounts as the need arises, if the new project provides system-wide benefits.[534] The Commission considered that this request indicates a misunderstanding of the role of prudent discounts. If a project has system-wide benefits it can be included in the asset base (through section 8.16(b)(ii) of the Code). This will result in all users contributing to its costs. Prudent discounts are appropriate to gain or retain users who would not be users at the proposed tariffs but would be users at lower tariffs which are higher than the incremental cost of servicing those users (in which case the

[532] TXU submission, 31 May 2002, p. 4.

[533] GasNet access arrangement, schedule 1, clause 1.3(f).

[534] Origin submission, 17 May 2002, p. 5.

users in question would contribute to common costs which would result in lower tariffs for other users).

Origin also suggested that a prudent discount is also appropriate for withdrawals from the UGS to the proposed SEA Gas pipeline and from the Longford plant to the EGP at the VicHub.[535] GasNet indicated that it was willing to work with VENCorp to design appropriate prudent discounts.[536] The Commission considered it appropriate that GasNet publish its proposal on these two issues in the form of a submission to this access arrangement process in time for interested parties to also make comments in their submissions to the Draft Decision.

It was suggested in submissions that GasNet and not VENCorp should offer any appropriate discounts. The Commission agreed that it would be simpler for one organisation to offer any prudent discounts required and that GasNet is best placed to do so. Further, to the extent that GasNet would apply the shortfall in revenue to other users in the same way that VENCorp would, the Commission considered that users and GasNet should be indifferent to which organisation offers the discount. The Commission stated that it understood that users are ultimately concerned with their final delivered price and if this is the same irrespective of the organisation implementing the discounting then users should be unconcerned.

It could be argued that if the discounting would produce a tariff lower than the marginal cost of the user to GasNet then VENCorp should take up the balance of the required discount. However, the result would not be different to GasNet reducing its tariff below marginal cost in order to implement the whole prudent discount (as long as it allocates the unrecovered costs to other users in the same way that VENCorp would have). In fact, GasNet and users should be indifferent even if the prudent discount were less than VENCorp's tariff, and required the GasNet tariff to be negative.

None of the proposed prudent discounts assessed above were below GasNet's marginal cost and thus the concerns addressed in the above paragraph were not immediate. However, the Draft Decision suggested that it may be that the two situations nominated by Origin will raise these concerns.

Further adjustments

The Commission noted in the Draft Decision that it was continuing to assess GasNet's cost allocation model with respect to whether it implements the procedures described in the proposed revised access arrangement. It also noted that, with the amendments the Commission proposed in the Draft Decision, adjustments would need to be made to some of the detail of the model and that the relativities between tariffs may be different to those originally proposed by GasNet.

8.1.6 Response to Draft Decision

GasNet generally agreed with the comments made by the Commission on the degree of congestion on specific pipelines. GasNet acknowledged that, with the development of

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535 ibid., p. 4.

536 GasNet response to submissions, 12 June 2002, pp. 17-18.

the Yolla field, the pipeline at Brooklyn is unlikely to be constrained and it has thus removed any looping of that pipeline from its capital expenditure forecasts.[537] GasNet acknowledged the potential for congestion on the Wollert to Wodonga pipeline but considered it impractical to levy a peak tariff on one pipeline only. With respect to the injection pipelines, GasNet states that congestion is much more likely as it can occur on the basis of users' sourcing decisions (where as congestion on withdrawal pipelines requires increases in demand which can generally be forecast) and peak signal pricing is consequently appropriate. It also stated that peak injection charges are levied on retailers (as opposed to withdrawal charges levied on end-users) who are in a position to be responsive to price signals. Finally, GasNet acknowledged that congestion may not be forecast to occur in the next access arrangement period but claimed it is likely in the subsequent period and to provide continuity in pricing there should continue to be a peak charge in the next access arrangement period.[538]

The EUCV insisted that 'users must contribute in proportion to their peak demand' because the system is designed for peak demand. It claimed that the prime purpose for charging for peak usage is for cost reflectivity and not to provide price signals to users. This is supported by Amcor and PaperlinX who claim that an anytime charge does not comply with the cost reflectivity requirements of the Code.[539] The EUCV also claimed that the Commission appears to accept GasNet's proposed move away from peak tariffs as the only way to achieve simpler tariffs.[540]

Several submissions suggested that the injection charge be based on peak volume over the winter period rather than over the 10 peak days. This would retain some peak price signals but reduce the administrative complexity.[541] They noted that it is impossible for retailers to directly attribute injection charges to individual customers.[542] TXU also requested that postcodes remain as the basic building block for the definition of zones and that zones be aggregated to avoid complexity.[543]

Origin stated that 19 zones increases the complexity and the cost reflectivity is unlikely to outweigh the added billing costs.[544] It claimed that the peak withdrawal tariffs failed to transmit signals to customers most likely to respond and considered it appropriate that they be removed although it did support peak usage pricing signals.[545] AGL stated that very few large customers would allow peak signals to influence their locational decisions and the signals do not get through to small customers.[546] It also noted that the annual 'wash-up' is difficult to achieve, being complicated by customer churn and lack

537 GasNet submission, 20 September 2002, p. 31.

538 ibid., p. 37.

539 Amcor and PaperlinX submission, 13 September 2002, p. 9.

540 EUCV submission, 13 September 2002, pp. 12-13.

541 TXU submission, 16 September 2002, p. 3; Origin submission, 18 September 2002, p. 6; AGL submission, 18 September 2002, p. 2.

542 TXU submission, 16 September 2002, p. 4, Origin submission, 18 September 2002, p. 5.

543 TXU submission, 16 September 2002, p. 7

544 Origin submission, 18 September 2002, p. 5.

545 ibid., p. 5.

546 AGL submission, 18 September 2002, p. 3.

of cooperation from all retailers.[547] It believed the proposed tariff structure does not give the appropriate balance between cost reflectivity, simplicity and not distorting investment.[548]

EnergyAdvice considered that it is not in end users' interests to face different tariff structures every five years. Users require predictable input costs on a timeframe much longer than 5 years. A long term consideration would produce tariffs which favour high load factor and counter-seasonal gas demands.[549]

Santos supported retention of the current tariff structure (with the peak charges over 10 days rather than five days) even though it acknowledged that consumers do not see the peak cost at the moment because retailers roll it into an average (bundled) tariff.[550]

With regard to the Murray Valley Pipeline, GasNet's initial response to the Draft Decision was to propose to set the tariff for Murray Valley users at a level which is just sufficient to pass the economic feasibility test, in order to encourage connection to gas by users of alternative fuels.[551] GasNet subsequently proposed to calculate a tariff for the Murray Valley Pipeline based on the incremental costs associated with the pipeline. The tariff will not follow the general cost allocation methodology of allocating 45 per cent of costs to peak usage. Instead it is proposed to allocate all capital costs to peak flows and all non-capital costs to annual flows. This maintains the current cost allocation methodology for the Murray Valley Pipeline in order to minimise tariff shock. As well as this incremental tariff, users will pay a tariff for use of the system to the entrance of the Murray Valley at Chiltern Valley. This tariff will be calculated using the standard cost allocation methodology which will include a share of joint costs.[552]

BHP Billiton noted GasNet's intention to recover from Murray Valley users the minimum revenue necessary for the pipeline to pass the economic feasibility test. It concluded that this implies a cross subsidy from other users which is inconsistent with the Code's requirements for cost reflectivity in tariffs.[553]

8.1.7 Final Decision

The Commission has reconsidered the issues discussed in the Draft Decision in the light of subsequent submissions. These considerations are below under the same headings as used in the Draft Decision. The one new issue raised since the Draft Decision, that of a different tariff approach for the Murray Valley zone, is addressed in its own section following the other issues.

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547 ibid.

548 ibid., p. 2.

549 EnergyAdvice submissions, 19 September 2002, p. 2 and 18 October 2002, p. 1.

550 Santos submission, 20 September 2002, pp. 5-6.

551 GasNet, Regulatory Treatment of Murray Valley Pipeline, 15 August 2002, p. 1.

552 GasNet, Murray Valley Tariff – Revised Proposal, 24 October 2002, p. 1.

553 BHP Billiton submission, 11 October 2002, p. 21.

Overall complexity

One submission to the Draft Decision suggested that postcodes remain as the basic building block for the definition of zones and that tariff zones should be aggregated to reduce complexity. The Commission notes that GasNet has responded to the first request by amending its proposed revised Schedule 2 to define withdrawal zones by postcode. The Commission agrees that aggregation of zones would reduce complexity, but at the same time it would also reduce the cost-reflectivity of tariffs. As noted in the Draft Decision, the Commission needs to balance these two competing claims on tariffs. The Commission notes that Origin also considers the tariff structure too complex and questions whether the cost reflectivity exceeds the cost of billing software redesign, although it gives no indication of this cost. Having re-considered the issue, the Commission remains unconvinced that the complexity will unduly hinder the market operation. In coming to this conclusion the Commission has been mindful of the interests of users and prospective users (section 2.24(f)) and the public interest in having competition in the market (section 2.24(e)) as well as the need for efficiency in the structure of the reference tariffs (section 8.1(e)) and a fair sharing of costs between users (sections 8.38 and 42).

Peak and non-peak relativities

In the Draft Decision the Commission considered that whether peak signals were appropriate depended on whether the system was constrained or had the potential to face constraint. EUCV, Amcor and PaperlinX have suggested that the Code's requirement for cost reflectivity requires the use of peak tariffs: that users must be charged according to their demand for system capacity and that the charging for peak usage is not primarily for sending pricing signals. The Commission notes that peak pricing can fulfil both functions. It also notes that the Code requires consideration of replicating competitive markets, not distorting investment signals (sections 8.1(b) and (d)) and economically efficient operation of the pipeline (section 2.24(d)). This requires a consideration of the appropriate pricing signals. While current or expected demand may have led to the current sizing of the system, efficient use of the system will mean that where constraint does not exist, or is not likely in the medium term, it would be inappropriate to implement a tariff structure that discourages usage.

Since the Draft Decision, GasNet has acknowledged the validity of the Commission's comments on congestion. The Commission also notes that with the advent of gas from Yolla, the Wollert to Wodonga pipeline is the only withdrawal pipeline likely to face the possibility of constraint (under certain conditions) in the medium term. The Commission also agrees with GasNet that even if a price signal were appropriate for this pipeline, it would be impractical to levy one only on that pipeline. Furthermore, as noted in the Draft Decision, there is little evidence that end users of the PTS respond to pricing signals.[554] The Commission considers that, on balance, it is quite unlikely that peak withdrawal tariffs have much effect on overall demand. Consequently, for the reasons noted above and in the Draft Decision, the Commission concludes that GasNet's proposal to remove peak withdrawal tariffs and simply levy an anytime tariff

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[554] While AGL and Origin offered their support to the view that customers are not likely to respond to peak signals, submissions to the Draft Decision did not provide any new arguments or evidence on the issue.

is appropriate. This change provides tariffs that meet the legitimate business interests of GasNet, the interests of users, promote efficiency and deliver a fair sharing of costs between users (pursuant to section 2.24 of the Code). Consequently, the Commission does not oppose GasNet's proposal to remove the peak withdrawal tariff.

The Commission considers that congestion, while not likely in the access arrangement period, is possible during most winters depending on the sourcing decisions of users (which are difficult to forecast and can change quickly). Congestion may be more likely in the third access arrangement period when more gas is expected to be available from the Otway basin and total demand will probably be higher. On balance, the Commission considers that while peak injection signals may not be necessary now, they may be required in the third access arrangement period.

The Commission notes the suggestion that injection charges be based on peak winter volumes instead of the 10 peak days. While this would reduce the complexity faced by users, it would also reduce the effectiveness of the peak signalling. Also, such a change would exacerbate the tariff shock many individual end-users will already experience from the implementation of the proposed changes.[555]

Few submissions mentioned the move from five peak days to 10 peak days as the charging parameter. There was a suggestion that this proposed move is a backward step as it makes it more difficult for users to avoid the peak days. The Commission does not consider this a valid objection. If users cannot predict the peak days to avoid peak charges they will have to modify their behaviour over the whole period in which the peak charges may arise. This is a desirable result from the peak signal.

The Commission notes comments from both GasNet and users that stability in tariffs is in the interests of users (section 2.24(f) of the Code) and considers that maintaining a peak injection tariff would facilitate the efficient use of the pipeline (section 2.24(d)) and not distort investment decisions (section 8.1(d)). Consequently, the Commission does not oppose GasNet's proposal to continue levying a peak injection tariff.

Cost allocation

The general approach to cost allocation is very similar to the approach adopted in the first access arrangement period and was discussed in the Draft Decision. The Commission continues to consider this approach an appropriate method (when adjusted for specific circumstances which are discussed below) of allocating joint costs to produce tariffs that are efficient, do not distort investment signals (sections 8.1(e) and (d)) and which fairly share these costs between services and users (sections 8.38 and 8.42).

In the 1998 Final Decision the Commission noted that the assumptions contained in the tariff model about the source of gas for various zones were simplified and flagged that in the 2002 review it would reassess the attribution of UGS as a source and the impact of this on tariffs. GasNet's proposed assignment process is explained in section 1.5 of Schedule 1 of the proposed revised access arrangement. No submissions were received

555 It would further increase the costs faced by users with flatter winter loads compared with those with peaky loads.

on this proposed assignment. The Commission considers that GasNet's tariff model adequately models this assignment of withdrawals to injection locations for the purposes of tariff calculations.

Operating costs are now allocated to the Western zone on the same basis as the rest of the PTS which the Commission considers consistent with the integration of the WTS (see the Draft Decision discussion).

Postage stamp allocation

As discussed in the Draft Decision, the Commission considers that it is appropriate to allocate existing indirect costs on a postage stamp basis. It also considers this an appropriate allocation basis for the asymmetric risk costs. However, the Commission considers that the unrecovered K factor adjustment should be allocated on a percentage basis as it would have been recovered from users if it had been recovered under the normal yearly adjustment mechanism. This approach would be consistent with the interests of GasNet, users and prospective users, and end-users (section 2.24 of the Code). GasNet has indicated that it agrees with this amendment.[556]

Amendment 33

GasNet must amend section 5.3 of its revised access arrangement information to allocate the K factor under-recovery of $12 903 127 (in 2003 dollars) to all tariffs (other than those for the Southwest Pipeline) as a uniform percentage increase.

The Commission also considers that capital raising costs should be allocated on the same basis as other capital costs. GasNet has indicated that it agrees with this amendment.[557]

Amendment 34

GasNet must amend section 5.3 of its revised access arrangement information to allocate capital raising costs on the same basis as it allocates depreciation and return on capital.

In the Draft Decision, the Commission rejected the proposal to include a return on working capital. The Commission now accepts (with amendments) this proposal (see section 6.2.5 of this Final Decision).[558] GasNet has proposed to allocate this cost on the postage stamp basis. It could be argued that users benefit from linepack in proportion to the length of pipeline they use. Benefits of the spare parts inventory are less clearly ascribed as they include pipe, valve components and compressor components. As the sum in question is relatively small (approximately $100 000 a year) the Commission considers it unreasonable to require an amendment to the allocation model. Consequently, the Commission has decided to accept GasNet's proposed allocation approach for working capital.

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556 GasNet submission, 20 September 2002, p. 38.

557 ibid.

558 Note that this working capital is not the usual definition of working capital (debtors, less creditors), a return on which the Commission has rejected in the past. See section 6.2.5 for further explanation.

Allocation by usage

In the Draft Decision, the Commission discussed the question of what proportion of costs associated with withdrawal pipelines should be allocated on the basis of peak (rather than annual) usage. It raised two questions: are there (or are there likely to be) constraints on the pipelines; and do users respond to pricing signals? As noted in the discussion on peak and non-peak relativities (above), the Commission considers that there is little likelihood of constraint on the withdrawal pipelines and that users are unlikely to respond to peak pricing signals. As discussed in the Draft Decision, under the current proposal of only two withdrawal tariffs (anytime tariffs for Tariff D and Tariff V) the peak signal is very muted, as it is limited to the difference between Tariff V and Tariff D. Even if the signal was not muted, most end-users are not able to respond to this signal by changing their customer category. Further, it is not clear to the Commission that the costs of servicing these end-users differ when there is no constraint on the system. Consequently, it can be argued that there is little reason for any differentiation between Tariff D and Tariff V end-users and no need to allocate any withdrawal costs on the basis of peak usage.

However, to allocate 100 per cent of costs on the basis of annual usage at this time would result in a very large tariff shock at a time when there will already be a shock from the removal of the peak withdrawal charge. GasNet proposes that 45 per cent of withdrawal costs be allocated on the basis of peak usage (compared to 55 per cent in the current access arrangement). This is a relatively small movement towards a common tariff for both classes of end-users which would not contribute much to the tariff shock. The Commission considers that it is in the interests of users (section 2.24(f)) and end-users (section 2.24(g)) to minimise any tariff shock and does not object to this aspect of the proposed cost allocation.

An exception to the above is GasNet's latest proposal for the Murray Valley Pipeline. GasNet proposes to allocate all capital costs on peak usage and all operating costs on annual usage. This is the approach implemented under the current access arrangement. GasNet claims this reduces the tariff shock for these users. This approach relates to that portion of the tariff which is based on the incremental costs of the Murray Valley Pipeline. Those costs associated with system usage up to Chiltern Valley will be calculated using the standard cost allocation model. The Commission considers this proposal for the Murray Valley zone is appropriate and accommodates the interests of GasNet in recovering efficient costs (see section 8.1(a) of the Code) and the interests of users (section 2.24(f)) while making a fair and reasonable allocation of costs.

Matched rebates

No submissions were received in response to the Draft Decision on this issue. Following the discussion in the Draft Decision, the Commission does not oppose the matched rebates GasNet proposes in its proposed revised access arrangement.

Cross-system tariff

No submissions were received in response to the Draft Decision on this issue. As indicated in the Draft Decision, the Commission accepts the proposed cross-system tariff.

Prudent discounts

No submissions were received from interested parties in response to the Draft Decision on this issue. As discussed in the Draft Decision, the Commission has concluded that the proposed prudent discounts have been determined in accordance with the requirements of the Code and are appropriate.

In its proposed revised access arrangement GasNet proposed a prudent discount for three withdrawal points within the Metro zone which are close to Pakenham, for matched injections at Pakenham.[559] In September 2002, GasNet provided an amended Schedule 1 to its proposed revised access arrangement. One amendment was to expand the number of withdrawal points subject to the matched withdrawal at Pakenham from three to 26 and to label these points as a new zone – 'Metro South East'.[560] No justification for this expansion was provided at that time. A subsequent letter from GasNet has indicated that the expansion of those points to which the matched discount is available is a practical necessity flowing from the interconnectedness of these points.[561] The Commission has considered this proposed change to the Pakenham prudent discount. It has found that it does not alter the financial assessment of the appropriateness of the proposal. The Commission has decided to accept the expansion of the withdrawal points which will be offered the matched withdrawal tariff as a technically reasonable adjustment (see section 8.38 of the Code).

Since the Draft Decision, International Power, Origin and TXU have announced their intention to build a single pipeline between the Otway basin and South Australia. However, whether this proposed pipeline will pose a bypass threat to the PTS remains unclear. To institute a prudent discount before there is a bypass threat would not be in the interests of users or prospective users (section 2.24(f) of the Code) and would be an unnecessary deviation from tariffs which contain a fair share of joint costs (sections 8.38 and 8.42). The Commission considers that waiting until there is a credible threat does not deny GasNet's legitimate business interests (section 2.24(a)). For these reasons, and the reasons in the Draft Decision, the Commission considers that GasNet should supply evidence of a credible specific threat before the prudent discount can be offered.

Amendment 35

GasNet must amend clause 1.3(g), schedule 1 of its revised access arrangement (as amended in September 2002) to require the provision of sufficient evidence to the Commission to support a claim that a specific bypass threat is credible. In addition, it must state that the introduction of the Warrnambool and Koroit prudent discounts would be subject to the Commission's approval.

In the Draft Decision the Commission considered it appropriate that GasNet publish its proposed response to Origin's suggestion that there be prudent discounts offered on withdrawals from the UGS to the proposed SEA Gas pipeline and from the Longford

[559] GasNet access arrangement, Schedule 1, p. 20.

[560] GasNet proposed amendments to revised access arrangement and draft access arrangement information, Schedule 1, 13 September 2002, pp. 6, 16-17.

[561] GasNet, Pakenham Prudent Discount Procedure, 30 October 2002.

plant to the EGP at the VicHub. In its proposed amendment to the revised access arrangement, GasNet has proposed a 'System Export Tariff' for Longford to the EGP of $0.00/GJ. GasNet noted the short distance between the two points and that VENCorp charges would still apply. It also noted that its injection charge would also apply and so proposes not to charge for withdrawal.[562]

For UGS/North Paaratte to the Port Campbell to Adelaide Pipeline (SEA Gas) GasNet proposes a tariff of $0.02/GJ to apply instead of the normal withdrawal tariff for that zone. GasNet notes various uncertainties surrounding the proposed SEA Gas pipeline including where it will connect to the GasNet system and that if gas were injected at the UGS and withdrawn at the SEA Gas pipeline, the injection charge would be zero. Consequently, it considers it reasonable to charge the notional withdrawal tariff mentioned above.

The Commission notes that no volumes are forecast for these two scenarios in the tariff model and therefore no other tariffs will be altered on the introduction of these two discounted tariffs. Such prudent discounts are in the interests of users and prospective users (section 2.24(f) of the Code) and are in the public interest as otherwise wasteful bypass would be encouraged (section 2.24(e)) which would also distort investment decisions (section 8.1(d)). Consequently, the Commission considers these proposed tariffs to be appropriate and accepts GasNet's proposal.

Murray Valley tariff

The proposed revised access arrangement included proposed tariffs for the Murray Valley zone which were derived from GasNet's cost allocation model.[563] As such, they included a share of the system's capital and operating costs. These costs are above the stand alone costs for the Murray Valley Pipeline itself. The proposed tariffs were $2.0377/GJ for Tariff D and $2.5556/GJ for Tariff V.

Subsequent to the Draft Decision, GasNet has altered its approach and proposes to calculate the tariffs in two parts: a tariff which covers the costs of system use from the source of gas to Chiltern Valley (the beginning of the Murray Valley Pipeline) and an incremental tariff covering the costs of the Murray Valley Pipeline. This is the same structure that has been used for the first access arrangement period. The calculation of the Chiltern Valley tariff is to be based on the standard cost allocation model (which was also the approach for the first access arrangement period). This should produce tariffs slightly less than the North Hume tariffs (as is the case for the first access arrangement period). The calculation of the incremental tariff is designed to recover in the next access arrangement period all the costs associated with the Murray Valley Pipeline for that period. This is the same approach as for the rest of the PTS (with the exception of the Southwest Pipeline). It is proposed that all capital costs be allocated to users (Tariff V or Tariff D) on the basis of peak usage and all non-capital costs be allocated on the basis of annual usage. This cost allocation approach is different to the proposed standard cost allocation model (which allocates 45 per cent of all withdrawal costs on the basis of peak usage) but is the same as the cost allocation methodology

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562 GasNet proposed amendments to revised access arrangement and draft access arrangement information, Schedule 1, 13 September 2002, pp. 1 & 7.

563 GasNet, Regulatory treatment of the Murray Valley Pipeline, 15 August 2002, p. 1.

used for the Murray Valley incremental tariff for the first access arrangement period. GasNet states that it has employed this methodology to minimise tariff shock for Murray Valley users.

The resulting proposed incremental Murray Valley tariffs are $0.7929/GJ for Tariff D and $1.7593/GJ for Tariff V. Using the proposed North Hume tariffs as a proxy for the Chiltern Valley tariff, the total tariffs for Murray Valley end-users are different to those proposed in March 2002 (Tariff V is nearly 40 cents higher and Tariff D is nearly 40 cents lower) but are similar to those under the current access arrangement.[564] This accords with GasNet's aim to minimise tariff shock. Minimising tariff shock is a particularly important consideration for Murray Valley which is a relatively new market with a customer base that is still developing. The Commission agrees with the new proposed approach, noting that it is in the interests of users to have relatively stable tariffs (section 2.24(f) of the Code).

However, the Commission is also mindful of the need for cost reflective tariffs which would result from the application of the standard cost allocation methodology. It recognises that this methodology cannot be implemented completely in this next access arrangement period without resulting tariff shocks. It does note, though, that tariffs for Murray Valley users in subsequent access arrangement periods are likely to be lower than those proposed for the next access arrangement period (due to the declining asset base) which would facilitate rebalancing the tariffs towards a more cost reflective level. The Commission considers that for the next access arrangement period an appropriate balancing of these competing considerations is for the method of cost allocation to be as close as possible to the standard approach as long as the resulting tariffs (for either Tariff V or Tariff D) do not increase over their current level. This is an appropriate principle for both subsequent revisions and for this current one.

The tariffs the Commission approves for Murray Valley for 2003 to 2007 will be lower than those proposed as a result of the Final Decision amendments, particularly the lower WACC. The Commission calculates that if 75 per cent (rather than the 100 per cent proposed) of the costs of Murray Valley are allocated on the basis of peak usage then this would result in a tariff for Tariff D customers which is approximately the same level as that proposed (and that paid in the first access arrangement period) and a tariff for Tariff V customers which would be less than that proposed by more than 30 cents/GJ. The Commission considers that this would produce an appropriate balance between the Code's requirements for tariffs to contain a fair and reasonable share of joint costs (sections 8.38 and 8.42) and the interests of users and prospective users in avoiding tariff shocks (section 2.24(f)). Consequently, the Commission considers it appropriate to accept the new proposed tariff structure for Murray Valley but to require 75 per cent of costs associated with Murray Valley to be allocated to users on the basis of peak usage.

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564 This assessment is based on assumed average load factors for Tariff V and Tariff D.

Amendment 36

In calculating tariffs, GasNet must amend its proposed revised access arrangement to calculate a tariff for Murray Valley users which is a combination of an incremental tariff for the Murray Valley Pipeline and a tariff for system usage to Chiltern Valley. These tariffs must be based on the standard cost allocation methodology (as expressed in GasNet's submission of 24 October 2002) except that GasNet must allocate 75 per cent (rather than 100 per cent) of Murray Valley costs to users on the basis of peak usage and 25 per cent on the basis of annual usage.

Conclusion

As discussed above, there are many competing Code requirements the Commission needs to take into account in considering GasNet's proposed tariff structure. In coming to its conclusions the Commission has been mindful of the interests of users and prospective users (section 2.24(f) of the Code) in having a structure that is easy to understand and implement and in not facing significant tariff shock; GasNet's legitimate business interests such as having tariffs that allow it to recover a revenue stream that covers efficient costs, and which facilitate market development (section 8.1(a)(f)); the need for tariffs which do not distort investment signals (section 8.1(d)) and the public interest in having competition in the market (section 2.24(e)) as well as the need for efficiency in the structure of the reference tariffs (section 8.1(e)) and a fair sharing of costs between users (sections 8.38 and 8.42) as well as the other aspects of sections 2.24 and 8.1 of the Code. The Commission notes that interested parties had widely differing views on this issue. The Commission has balanced competing interests in coming to its decision.

The Commission considers that the tariff structure and cost allocation methodology proposed by GasNet, as modified by the Commission's amendments, offer an appropriate balance to the (sometimes competing) requirements of the Code. This structure is not the only one that could have been considered appropriate by the Commission, but it is the one proposed by GasNet and the Commission considers that it complies with the requirements of the Code (as modified by the required amendments).

8.2 Tariff path

8.2.1 Code requirements

Section 8.3 of the Code provides discretion to service providers in how the reference tariffs may be varied during an access arrangement period. For example, tariffs may change according to a price path. That is, tariffs follow a path determined at the start of the period without adjustment for subsequent events until the commencement of the next access arrangement period. An alternative method is a cost of service approach where tariffs are set on the basis of anticipated costs and are adjusted throughout the access arrangement period in light of actual outcomes. The Code also allows variations or combinations of these approaches to be used.

8.2.2 Current access arrangement provisions

The current reference tariff policy (section 5.3 of the access arrangement) states that a CPI-X price path approach consistent with section 8.3 of the Code will apply to the tariffs for the PTS.

An average revenue control is applied to GasNet and each year the tariffs to be charged are altered in accordance with the Tariff Order (Part A of Schedule 5). The average revenue control requirement is that the forecast average transmission tariff (FATT) must be less than the maximum average transmission tariff (MATT). For each year the FATT will be the weighted average of the proposed tariffs, using the latest forecast volumes for the weighting. The MATT calculated each year is the average transmission tariff (ATT) for that year (as determined in 1998 and adjusted by CPI-X for each year since) less K. The X factor is a smoothing mechanism (not a productivity factor) and was set at 2.7 per cent for the initial access arrangement period. The K factor is a correction factor that aims to correct for any differences in average revenue resulting from differences between forecast and actual product mix.[565]

Following the calculation of the MATT for the forthcoming year each individual tariff can be adjusted. The maximum increase that can be applied to any individual tariff is CPI+Y where Y was set at –1.7 per cent for the initial access arrangement period. This has the effect of limiting the ability of GasNet to move away from the tariffs that were accepted by the Commission in 1998.[566]

Consequently, at each year the average tariff for the PTS is calculated with reference to the average tariff set at the start of the access arrangement period, CPI, X and the difference in revenue resulting from differences between actual and forecast product mix (K). Each individual tariff can be altered subject to the re-balancing control (Y). As a result, at the conclusion of year seven (when the full K factor impact for the initial access arrangement period has flowed through to tariffs) it would be expected that GasNet would have obtained the average revenue determined as appropriate by the Commission in 1998.

The Tariff Order also sets out, at clause 9.2, a number of fixed principles to apply for the duration of the subsequent access arrangement. These include:

- utilise incentive-based regulation adopting a CPI-X approach and not rate of return regulation; and
- set the X factor in the CPI-X formula so that only one X factor applies without revision for the entire subsequent access arrangement period.

565 Product mix refers to the balance of usage between Tariff V and Tariff D customers within zones, the balance between zones and the balance between peak and anytime demand. A change (between forecast and actual) in the proportions of any of these categories will affect the average revenue achieved.

566 It effectively means that no tariff can be increased more than one percentage point above the CPI-X increase.

8.2.3 GasNet proposal

In general, GasNet is proposing to retain the existing approach which it regards as a price path approach. That is, tariffs are determined for the initial year of an access arrangement period and then move according to the price control formula mechanism in accordance with schedules 3 and 4 of the access arrangement. It considers that the use of a price path constitutes an incentive mechanism and exposes GasNet to both volume and cost risk.[567]

GasNet also proposes to retain the average revenue control mechanism. However, there are some differences that it proposes for this new access arrangement period which are outlined in the following discussion.

Schedule 3 of the proposed revised access arrangement sets out the process to be followed by the Commission and GasNet for the annual tariff adjustment. In brief, GasNet is required to submit tariffs for the forthcoming regulatory year (which is 12 months from 1 January) at least 15 business days before the start of that year. The Commission must then assess whether those tariffs comply with the formulae set out in schedule 4 of the access arrangement. Schedule 3 provides the Commission with 15 business days in which to assess GasNet's proposal. If GasNet has not received a notification from the Commission within 15 business days the Commission is deemed to have approved the proposal.

Schedule 4 of the proposed revised access arrangement sets out the price control formula that would apply for each annual tariff alteration. The schedule provides that the maximum average transmission tariff will move over the access arrangement period according to CPI-PPT where PPT is 4.5 per cent and is the weighted average of the X factors.[568]

The rebalancing control formula used in the subsequent calculation of individual tariffs allows any individual tariff to increase by up to two percentage points more than the increase in MATT provided that overall MATT remains unchanged. This is a significant change over the formula in the current access arrangement. First, the current formula only allows a one percentage point difference. More significantly, the current formula allows individual tariffs to be one percentage point above the rise in ATT, not MATT. This created the K factor revenue under-recovery discussed in section 6.2.2.

An X is also identified for each individual tariff in schedule 1 of the proposed revised access arrangement. Many individual tariffs have an X of five per cent. However, a number of tariffs have an X factor of zero. As a result, the weighted average X factor for all tariffs (PPT) is 4.5 per cent. The tariffs with a zero X are:

- injection at Port Campbell and Dandenong;
- withdrawal at Murray Valley and for storage at LNG and UGS;
- matched withdrawal at Murray Valley, Wodonga and Pakenham; and

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[567] GasNet access arrangement information, 27 March 2002, p. 30.

[568] The formula used is $(1+CPI)\times(1-X)$. GasNet access arrangement, 27 March 2002, p. 34.

- prudent discount tariffs for withdrawals in the Western zone.

Clauses 4.9 and 4.10 of the proposed revised access arrangement allow GasNet to amend tariffs within the access arrangement period for pass through events and the alteration of tariff zones. These clauses are discussed in detail in chapter 3 of this Final Decision.

8.2.4 Submissions to Issues Paper

A number of submissions expressed concern at the tariff path proposed by GasNet for the forthcoming access arrangement period. ENERGEX stated:

> An increase of 11% in real terms is frankly unacceptable in a commercial climate where industry, governments and the community is seeking efficiency gains from infrastructure owners.[569]

A similar view was expressed by Pulse who suggested that the lump sums associated with efficiency gains and the K factor should be treated as annuities to avoid steps in the tariff path.[570]

TXU also regarded the proposed tariff path as unacceptable, noting it was 'surprised' at the proposal. In particular, TXU suggested that 'the Commission should consider making it a precondition of approving the GasNet access arrangement on the basis that the Reference Tariffs reflect a smooth transitional from the current level in 2002 to the level required by 2007'.[571]

In addition, Origin did not regard the proposed tariff path as appropriate for a regulated business. It stated that it understood that the tariff path for the forthcoming period 'reflects a view that tariffs in the third access period will be much lower and are designed to avoid a "price shock" in the transitional year between the end of the second access period and the start of the third access period'. Origin regarded this as inconsistent with the proposed price shock for the first year of the forthcoming period and considers that a 38 per cent increase in tariffs will have a substantial impact on the market.[572]

EnergyAdvice calculated tariffs on the basis of GasNet's proposal for customers located in various zones and with different load profiles. On this basis EnergyAdvice stated that the average effect of GasNet's proposals across zones is an increase in tariffs of approximately 26 per cent in the first year. EnergyAdvice also commented that 'the impact of the significant price shock is not only prohibitive to new cogeneration projects but also adds considerably to the marginal cost of gas fired generation'.[573]

More specifically, DEI estimated that the proposed changes to tariffs will result in an effective increase of up to 171 per cent for gas injected into the PTS at Longford. DEI

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569 ENERGEX submission, 9 May 2002, p. 5.

570 Pulse submission, 16 May 2002, p. 5.

571 TXU submission, 31 May 2002, p. 33.

572 Origin submission, 17 May 2002, p. 8.

573 EnergyAdvice submission, 30 May 2002, p. 9.

noted that ‘given there has been no, or little, augmentation on this section of the network, this increase does not seem warranted’.[574]

8.2.5 Draft Decision

GasNet described its form of regulation as a price path approach. This method provides a service provider with incentives to out perform the forecasts that are used in establishing the price path.[575] However, GasNet has modified its price path, which can generally be thought of as a CPI-X mechanism, to accommodate some actual events within the access arrangement period. This is done firstly by the K factor, which ensures that GasNet has the opportunity to achieve the average revenue set at the start of the access arrangement period. In addition, GasNet has proposed a pass through mechanism that extends to a number of costs that may alter within the period. Both these mechanisms reduce the incentive benefits of the initial price path approach established by CPI-X. In fact, the pass through mechanism is an element of a cost of service approach. As a result, the Draft Decision noted that it would appear to be incorrect to suggest GasNet has established a true price path approach and is subject to the incentives suggested by this description. It would be more correct to describe GasNet’s approach as complying with section 8.3(c) of the Code, that is, a combination of a price path and cost of service approach.

As noted above, the Tariff Order established a number of fixed principles for this next access arrangement period. Fixed principles can only be changed with the agreement of the service provider. However, as GasNet has not proposed to alter any of the fixed principles, the proposed revised access arrangement must also comply with these principles.

The first principle of relevance noted above is the requirement to use a CPI-X approach and not a rate of return approach. While GasNet has proposed to modify its price path mechanism further with the introduction of an expanded pass through mechanism, the basis of regulation for GasNet remains CPI-X. The approach has not been altered to the extent that it could be accurately described as rate of return. The Draft Decision concluded that GasNet had complied with this fixed principle.

The second fixed principle is that only one X factor is to apply throughout the entire access arrangement period. The Commission interprets this principle as requiring an X to be set for the whole period and not vary year to year within the period. GasNet has proposed an X of zero for some tariffs and five per cent for other tariffs. This does not conflict with the fixed principle as these X factors are constant over the entire period. GasNet has complied with this fixed principle.

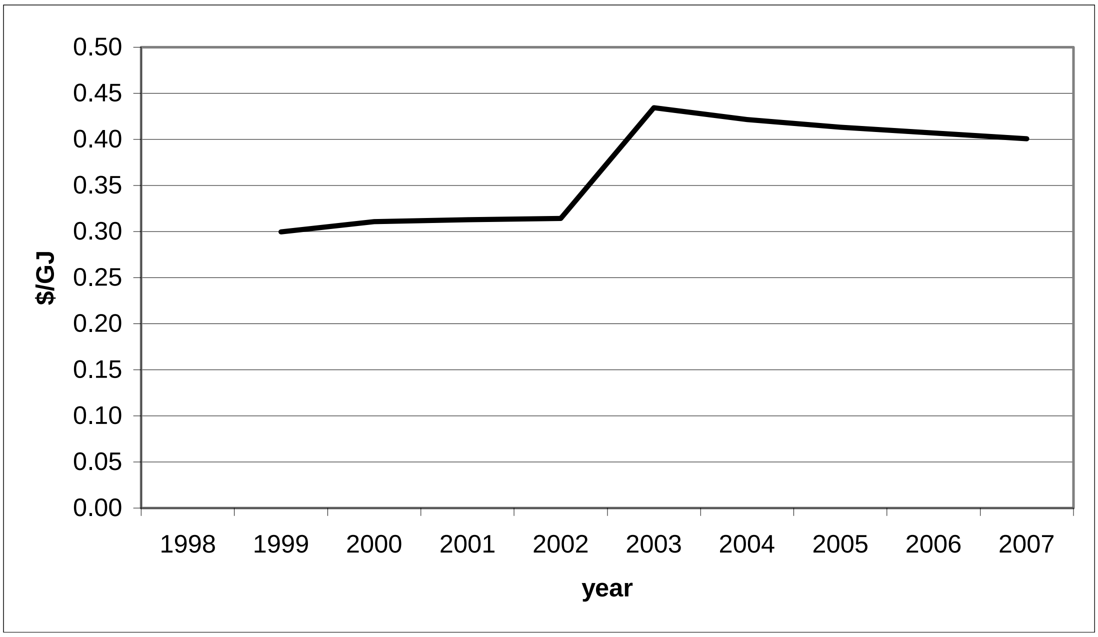
The tariff path for the ATT for 2003 to 2007 reflects the revenue requirement, or target revenue, established by GasNet in its proposal. In addition to the movement of tariffs within the access arrangement period, there is a step in the average tariff from 2002 to 2003. This change largely reflects GasNet’s proposed increase in revenues based on the proposed change in the capital base and an increase in the rate of return to 8.22 per

574 DEI submission, 13 May 2002, pp. 3-4.

575 One pipeline that has price path approach in this sense is the Central West Pipeline.

cent. As illustrated in the figure below, the change from 2002 to 2003 is significant, approximately 38 per cent.

Figure 8.1: Nominal average transmission tariff path, 1998 to 2007



Source: GasNet access arrangement information, 27 March 2002, p. 15; GasNet submission, 27 March 2002, p. 104; TPA access arrangement information, 30 November 1998, p. 17; ACCC analysis.
Note: For 1998 to 2002 the FATT is illustrated. For 2003 to 2007, the ATT is illustrated.

The figure above indicates the change in average tariffs. Customers in different zones will experience significantly different changes in their tariffs between 2002 and 2003. For example, customers with a 50 per cent load factor in the Metro, Wodonga, South Hume and Carisbrook zones will incur an increase. Users with the same load factor in the zones Tyres, Lurgi, Echuca and Latrobe will experience decreases (between 20 and 50 per cent).

It should also be noted that the change in tariffs also varies according to the load factor of the user. In comparison to the changes noted above, if a load factor of 100 per cent is assumed, increases occur in Metro, North Hume, Wodonga, South Hume and Murray Valley. Only Murray Valley Tariff D users will experience an increase less than 40 per cent.

The difference in the proposed tariff change between 2002 and 2003 suggests that the greater burden of recovering the proposed increased revenue is to fall on users with high load factors. This will tend to be Tariff D users.

The Draft Decision noted that as a consequence of various amendments proposed by the Commission the revenue requirement is less than that proposed by GasNet and the proposed tariff path will be inappropriate.

The Commission stated that in general, it would be reluctant to accept any tariff path of the shape proposed by GasNet, that is, a large initial increase followed by a substantial fall over the access arrangement period. It also acknowledged that the proposed tariff path is a concern to users and other interested parties.

The Draft Decision identified three aspects that must be considered when determining an appropriate tariff path. These are:

- the initial change in tariffs (for GasNet this is the change between 2002 and 2003);
- the movement of tariffs within the period (as indicated by X); and
- the change in tariffs at the end of the period moving into the subsequent period (for GasNet this the change from 2007 to 2008).

It also noted that GasNet appears to be particularly concerned with the third aspect to the detriment of other users of the PTS.[576]

The Commission acknowledged the desirability of a smooth transition between the tariffs for 2007 and 2008 (a reason GasNet gave for its proposed tariff path). However, a smooth transition between 2002 and 2003 and the slope of the path are also important considerations. Consequently, a balance between the three aspects of the tariff path must be found.

The Commission suggested in the Draft Decision that a tariff path with an initial tariff change between 2002 and 2003 of approximately four per cent with a CPI-X path over the subsequent years with an X factor of two per cent (inflation assumed to be 2.5 per cent) would be more appropriate than GasNet's proposal. An indicative estimate of the tariff movement between 2007 and the estimated tariff for 2008 for this tariff path is a fall of approximately 14 per cent.

In suggesting this tariff path in the Draft Decision the Commission placed a little more weight on limiting the extent of the initial tariff movement and degree of the path slope within the period. This is because the target average tariff for 2008, and consequently the end period tariff change, is the least certain element.

The Draft Decision also noted that GasNet proposed an X of five per cent for some tariffs while others have an X of zero. In light of the proposed amendments, the Commission stated that GasNet could apply a single X factor to all reference tariffs.

The Commission concluded that GasNet should establish a forecast average tariff path for the period 2003-2007 that produces a small nominal increase in the average tariff over the period with a limited initial increase (between 2002 and 2003).

The Commission did not receive any submissions in reference to the annual tariff assessment process. Nonetheless, the Draft Decision proposed a number of amendments to GasNet's proposed revisions.

The proposed schedule 3 of the access arrangement provides 15 business days for the Commission to assess an annual tariff proposal from GasNet. The current provisions

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[576] Although it states that it has selected an X 'which it believes reasonably balances the tariff changes at the commencement of the next and the subsequent Access Arrangement Periods'. GasNet response to submissions, 12 June 2002, p. 10.

contained in the Tariff Order state that GasNet must provide its proposal at least 30 business days prior to the commencement of the new regulatory year. The Commission then has 20 business days in which to assess the proposal and notify GasNet of its decision. In the Commission's experience the current time frames are adequate and appropriate but a reduction would limit the Commission's ability to adequately assess the proposed changes. Accordingly, the Draft Decision included a proposed amendment to the effect that the current time frames as specified in the Tariff Order are included in the proposed schedule 3 of the revised access arrangement.

Chapter 6 of the Tariff Order includes provisions to the following effect:

- the annual tariff statement must set out the proposed tariff components for each of the tariffs (clause 6.1(a)(1)(B)); and
- the Commission must approve an annual tariff statement if all the forecasts included in the statement are satisfactory to the Commission (clause 6.1(f)(2)).

The Commission noted that schedule 3 of the proposed revised access arrangement does not include these provisions. The annual assessment of tariffs requires sufficient information on tariff components to allow a full assessment to be undertaken and this should be provided. In addition, it was noted that if GasNet is to retain the ability to update forecasts within an access arrangement period rather than use the initial forecast data for the entire access arrangement period then the Commission requires discretion to determine whether the new forecasts are appropriate to use. Accordingly, the Draft Decision proposed an amendment to the proposed revised access arrangement to include the Tariff Order provision noted above.

8.2.6 Response to Draft Decision

The Commission received support from some interested parties in regard to its comments on the appropriate tariff path for GasNet for the forthcoming access arrangement period. For example, the EUCV stated:

> The requirement of the ACCC to have a tariff path which has a zero or small increase at 2003, and only small deviations for the access arrangement period, is strongly supported.[577]

TXU noted that a flatter path would 'reduce the potential for price shock to end use customers'.[578] It also noted that the Draft Decision did not include a proposed amendment regarding tariff path. It requested that an amendment be incorporated in the Commission's Final Decision. Origin and AGL also expressed similar views.[579]

GasNet stated that it accepts there is a need to balance the three factors identified by the Commission in its Draft Decision and has undertaken to recalculate the tariff path with regard to these principles. However, it also 'believes it is appropriate to expect some

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577 EUCV submission, 13 September 2002, p. 13. See also BHP Billiton submission, 13 September 2002, p. 14.

578 TXU submission, 16 September 2002, p. 8.

579 Origin submission, 18 September 2002, p. 2; AGL submission, 18 September 2002, p. 4.

increase in zonal tariffs to allow for the inclusion of that part of the SWP which is rolled-in under the system-wide benefits test'.[580]

In regard to X, 'GasNet believes it is appropriate to maintain a zero X-Factor in certain zones'. For example, where there is a threat of bypass.[581]

The Commission has not received any response from interested parties or GasNet in relation to the Draft Decision's proposed amendments 27 and 28 regarding clause 6.1 of the Tariff Order.

8.2.7 Final Decision

As noted by a number of interested parties, the Commission did not include a proposed amendment specifying a tariff path in its Draft Decision. This has also been discussed at various meetings with interested parties.

The Commission did not include a proposed amendment in the Draft Decision as it recognised that there may be some revenue aspects of the access arrangement that may change in the Final Decision. These include some CAPM parameters and the rate of expected inflation to apply to the revenue model. The exclusion of a proposed amendment also provided GasNet with the flexibility and opportunity to develop a new proposed tariff path in response to the Commission's Draft Decision.

The Commission recognises that an amendment specifying an appropriate tariff path will be required in this Final Decision. This follows the discussion below.

It appears from submissions that interested parties are particularly concerned about the initial price change from 2002 to 2003. This contrasts with GasNet who appears to consider that a step in tariffs would be expected by users and is justified on the basis that the Southwest Pipeline enters the capital base in 2003.

The Commission agrees with GasNet that the introduction of the Southwest Pipeline to the capital base in 2003 would result in a step in the benchmark regulated revenue from 2002. However, this step will be countered to some degree by the decline in the asset base that would otherwise occur, as well as any decline in the rate of return for the second access arrangement period. Following the amendments in this Final Decision, the net effect of these factors is an increase of approximately 19 per cent in the benchmark regulated revenue (in nominal terms) from 2002 to 2003.

While an initial step of 19 per cent is considerably less than the step proposed by GasNet, it is coupled with an X of approximately seven per cent. In having regard to the requirements of section 8.1 of the Code as well as the interests of users (section 2.24(f)), the Commission does not accept that this tariff path is appropriate as it provides users with a significant step coupled with an X that produces a substantial decline in tariffs over the period. The Commission considers that it is generally preferable to limit any tariff shock to users where possible while still ensuring that the

[580] GasNet submission, 20 September 2002, p. 38.

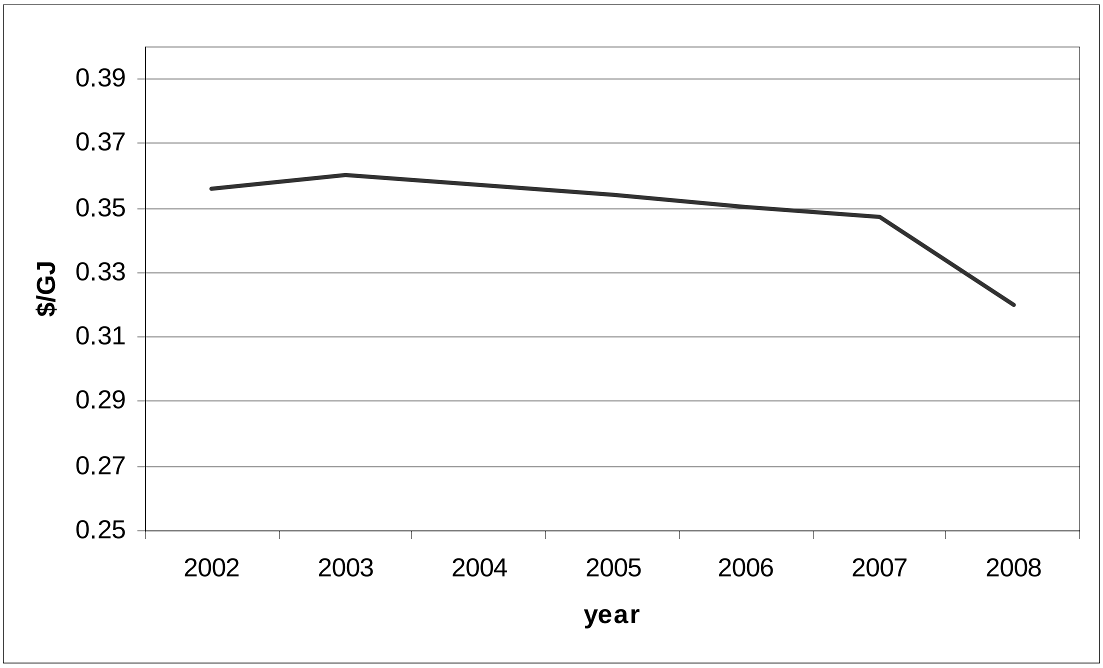
[581] ibid., p. 37.

service provider has a reasonable expectation of earning the required revenue over the period.

Consequently, the Commission has smoothed the expected average tariff path for GasNet for the forthcoming access arrangement period. This has been carried out with reference to finding a balance between the initial step in tariffs (between 2002 and 2003) and the tariff path over the period (2003 to 2007).

Following this approach, the Commission has determined that an appropriate balance in this instance is where X is three per cent and the initial tariff step is approximately 10 per cent. On the basis of the expected inflation rate of 2.16 per cent, this provides a small decline in the real average tariff over the access arrangement period. An illustration of the expected nominal tariff path is provided in Figure 8.2 below.

Figure 8.2: Expected nominal tariff path, 2003 to 2007



Source: ACCC analysis.

It should be noted that while this results in an initial increase in the average regulated tariff of approximately 10 per cent, the change in average tariffs paid by users and collected by GasNet will not be significant. This is because the average tariff achieved by GasNet includes the average regulated tariff plus an amount for the Southwest Pipeline. Consequently, the Commission anticipates that GasNet's total revenue, and average tariff, for 2003 will be similar to 2002.

The Commission has considered GasNet's proposal to implement an X of zero at certain points on the system that it considers to be under threat of bypass. In reference to section 2.24(a) of the Code, the Commission considers that it is appropriate for GasNet to have the ability to price its services with regard to market developments. Without this ability GasNet may find assets have limited usage. Users may also find unnecessary duplication of assets arising. As a result, users may ultimately pay more for their gas and service providers may not be able to recover their investments. This outcome would not be in the interest of either GasNet or users. Accordingly, the Commission has decided to accept GasNet's proposal to have an X of zero for selected tariffs as specified in the proposed schedule 1 of the revised access arrangement.[582]

In conclusion, with the exception of the specific tariffs noted above, the Commission requires GasNet to implement an X in its CPI-X price path of three per cent.

Amendment 37

GasNet must replace the proposed X of five per cent in schedule 1 of the revised access arrangement with an X of three per cent.

As discussed in section 8.2.5 above, the Commission proposed two amendments to the proposed revised access arrangement in relation to the annual tariff assessment process in its Draft Decision. These proposed amendments did not attract any comments from interested parties or GasNet.

The Commission has considered the amendments further and remains of the view that the procedures are necessary for the smooth operation of the assessment process. The Commission does not consider that these amendments conflict with GasNet's business interests pursuant to section 2.24(a) of the Code.

Accordingly, and for the reasons outlined above and in the Draft Decision, the Commission requires GasNet to amend annual tariff assessment process in the access arrangement.

Amendment 38

GasNet must amend schedule 3 to its revised access arrangement so that the annual tariff review time frames currently in clause 6.1 of the Tariff Order are retained. GasNet must also include the provisions currently in clauses 6.1(a)(1)(B) and 6.1(f)(2) of the Tariff Order in schedule 3 to its revised access arrangement.

8.3 Compliance with tariff principles

8.3.1 Code requirements

Section 3.5 of the Code requires the 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.

The reference tariff policy and reference tariffs should be designed to achieve a number of objectives that are outlined in section 8.1 of the Code:

(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 that Service;

[582] This will result in the average weighted X (PPT) being slightly less than three per cent.

(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 they can best be reconciled or which of them should prevail.

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 the 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 this 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 this 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 this 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 this 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 sections 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, section 8.1 includes objectives that may, at times, be in 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 states:

... In assessing a proposed Access Arrangement, the Relevant 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;

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

The recent WA Supreme Court Epic decision provides guidance as to the appropriate application of sections 8.1 and 2.24 by a regulator. The Court 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).[583]

8.3.2 Commission's considerations

The Commission considers that GasNet has complied with section 3.5 of the Code in providing a reference tariff policy in the access arrangement. A discussion on the reference tariff policy and the reference tariff methodology is located at chapter 3 of this Final Decision.

Each of the aspects of the reference tariff and reference tariff policy has been assessed in the relevant sections of this Final Decision together with a discussion of why the proposed amendments are necessary given the relevant provisions of the Code. The following discussion draws together the Commission's conclusions within the framework of sections 8.1 and 8.2 of the Code.

As noted in section 1.2 of this Final Decision, pursuant to section 2.46 of the Code, when assessing proposed revisions to an access arrangement the Commission must take the factors set out in section 2.24 and the provisions of the access arrangement into account. The Commission has given due consideration to each of these factors in assessing GasNet's proposed reference tariff and reference tariff policy (and the other elements set out in sections 3.1 to 3.20 of the Code) particularly where the objectives in section 8.1 conflict and the Commission, as the relevant regulator, must balance and reconcile these objectives. In addition, where the Commission has exercised a discretion, it has been guided by the criteria in section 2.24.

The following discussion specifically comments on the application of these factors in respect of the reference tariff and reference tariff policy.

Section 8.1 objectives

Recovery of efficient costs associated with the provision of reference services (8.1(a))

Section 8.1(a) provides that one objective which a reference tariff and a reference tariff policy should be designed to achieve is to provide the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference services over the expected life of the assets used in delivering that service.

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[583] Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at paragraph 85.

In the Epic case the Court noted that this objective does not necessarily set a ceiling or floor of the revenue that a service provider may earn. That is to say, the objective is not a revenue stream that recovers no more than efficient costs or at least efficient costs.[584] In assessing GasNet's proposed rate of return (see chapter 5 of this Final Decision) against this objective the Commission has also had regard to the factors (a), and (d) to (f) in section 2.24 of the Code. The Commission notes that in the Epic decision the Court took the view that 'legitimate' business interests are not limited to the recovery of normal profits or an economically efficient revenue stream.

It is important to note that the Commission does not consider this criterion guarantees a right for a service provider to recover monopoly profits. Criterion (a), to the extent that it allows such recovery, must be weighed against other criteria in section 2.24. While weight must be given to each of these criteria, it ultimately falls to the Commission as the relevant regulator to decide how they should be balanced.

The Commission has applied this framework to its consideration of the proposed reference tariff policy. It has also considered capital and non-capital costs proposed by GasNet. Many of these costs have been determined as not unreasonable costs for a prudent service provider. However, a number of adjustments are required to particular cost categories.

The Commission considers that the amendments it requires to be made to the reference tariff policy will generate a revenue stream that will be more comparable with the efficient costs of providing the reference service and are consistent with the objective in section 8.1(a) and the factors in section 2.24. It does not consider the legitimate business interest of GasNet requires a different outcome.

Replicating the outcome of a competitive market (8.1(b))

Setting the regulated rate of return of CAPM benchmarks results in a return that is expected to be similar to those achieved by firms facing similar commercial risks operating in a competitive environment. The return will be based on only those assets necessary to deliver the services required, consistent with section 2.24(d).

The reference tariffs will also allow GasNet to achieve a return in excess of a normal return from increased efficiencies and growth in sales, as occurs in a competitive market. However, over time, as in a competitive market, this benefit will pass onto customers. The Commission has proposed the efficiency carryover mechanism to encourage efficiencies and ensure that they are shared appropriately. In exercising this discretion to ensure the design of the reference tariff is consistent with the objective in section 8.1(b) of the Code the Commission has had regard to the factors in section 2.24 and notes that it regards the incentive mechanism and benefit sharing approach with the required amendments as benefiting both GasNet and users (see sections 2.24(a) and (f)).

Efficiency, equity considerations and a balancing of a service provider's interests with those of users and proposective users generally support a tariff path with a levelised real tariff over time, or one that declines slightly in real terms to reflect declining costs

[584] ibid., at paragraph 142.

relative to output. The Commission's modeling of tariffs indicates that such a tariff structure is achievable for GasNet (see section 8.2 of this Final Decision).

Pricing reflective of efficient costs is also a feature of competitive markets and, as noted in reference to section 8.1(a) above, the Commission aims to ensure that tariffs are reflective of efficient costs to the extent that this is practicable and reasonable.

There are some changes to the cost allocation and tariff structure for the period from 2003 to 2007 in comparison to the initial access arrangement period. As discussed in section 8.1 of this Final Decision, the Commission has concluded that the proposed approach is acceptable and, with the required amendments, will satisfy section 8.1(b) of the Code.

Ensuring the safe and reliable operation of the pipeline (8.1(c))

The reference tariffs are based on cost forecasts as being necessary for the safe and reliable operation of the pipeline. Each review of the access arrangement provides an opportunity for GasNet to increase its revenue if the safety and reliability of the pipeline demands it. GasNet may also submit early revisions to the access arrangement if desired. In addition, from the commencement of the forthcoming access arrangement period the access arrangement will include a pass through mechanism. This mechanism includes costs incurred as a result of requirements from the Office of Gas Safety. Other factors that will tend to preserve the integrity of the system include the contractual arrangements between GasNet and VENCorp to maintain the SEA.

The Commission considers that with the amendments required in this Final Decision the proposed costs for the PTS will remain appropriate for the safe operation of the pipeline system and are consistent with the objectives in section 8.1(c) and criterion 2.24(c) of the Code.

Not distorting investment decisions (8.1(d))

Efficient investment decisions upstream and downstream will be facilitated by transmission pricing based on an allocation of costs to users which approximates long run costs of providing the service. This is approximated by the adoption of tariffs which are consistent with sections 8.38 to 8.43 of the Code. Efficient investment decisions for pipeline systems are also likely to follow if an appropriate rate of return is applied to the asset. The return should be neither excessively high so as to encourage over investment, nor so low as to discourage efficient investment in the pipeline. In addition, it should be noted that excessive returns may discourage efficient investment in upstream and downstream markets. Conversely, inadequate returns may encourage upstream and downstream over investment in the short term (but may lead to lower investment levels in the longer term).

The return should be considered in conjunction with other aspects of the access arrangement to understand the full regulatory framework in which the business operates. In the case of GasNet, over investment is unlikely to be encouraged due to the redundant capital policy provisions in the access arrangement.

In addition, the extensions and expansions policy will provide GasNet with discretion regarding the coverage of extensions, providing flexibility to meet the needs of a growing market and the potential to earn returns greater than the benchmark nominated by the Commission.

GasNet has raised concerns regarding potential bypass situations that may arise in the future. The Commission considers that the revised access arrangement will provide GasNet with the flexibility to manage these situations as they occur and in anticipation of the event occurring. This includes the ability to use prudent discounts, the redundant capital policy and its depreciation schedule.

Accordingly, the Commission considers that with the required amendments in place, the revised access arrangement will not have a tendency to distort investment decisions in upstream and downstream markets or in regard to the PTS in particular and is consistent with the objectives in section 8.1(d) and the factors set out in section 2.24.

Efficiency in the level and structure of reference tariffs (8.1(e))

The Commission has assessed the proposed approach to the allocation and recovery of costs. It considers that the resulting approach strikes a balance between GasNet's legitimate business interests (section 2.24(a)), the efficient operation of the pipeline (section 2.24(d)) and the interests of users (section 2.24(f)) and satisfies the Code (in particular section 8.1(e), 8.2(a) and 8.2(b)) and should therefore be accepted.

A number of amendments to the costs forecast by GasNet are required by the Commission. The purpose of these amendments is to ensure the level of tariffs, on average, will be more appropriate and reflect the economically efficient operation of the pipeline (section 2.24(d)).

The Commission does not consider that the tariff path proposed by GasNet is appropriate or that it meets the Code principles. In response to concerns from interested parties, the Commission has proposed that the tariff path be levelled, to the extent practicable, over the access arrangement period taking into account potential tariff shocks at the start and end of that period. The Commission considers that a level tariff path is in the interest of users and prospective users (section 2.24(f)). It also considers that it is not inconsistent with GasNet's legitimate business interests pursuant to section 2.24(a) as it maintains the total revenue for the period that the Commission has considered to be appropriate.

Incentives to reduce costs and expand the market (8.1(f))

GasNet's exposure to changes in total demand and use of forecast costs provide an incentive to develop the market for gas and achieve efficiencies in operations and maintenance and capital expenditures. In addition, the Commission has accepted specific costs for market development by GasNet.

The Commission considers that in the second access arrangement period the adoption of the rolling carryover approach for operations and maintenance costs will continue to provide GasNet with the initial benefits of achieving efficiencies while ensuring that the benefits are passed onto users in the longer term.

The Commission has required some amendments to be made to the proposed forecast costs and the proposed benefit sharing mechanism. The Commission anticipates that GasNet will have an incentive to reduce costs and develop the market as required by section 8.1(e). The Commission considers that the benefits that arise ensure that this approach is in the interest of GasNet, users and prospective users.

Section 8.2 factors

Section 8.2 of the Code contains the following five factors about which the Commission, as the relevant regulator, must be satisfied in determining 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 (8.2(a))

Total revenue is to be determined by either the cost of service, IRR or NPV methods (or a variation or combination of these approaches). GasNet has adopted a Cost of Service approach with the use of a cost of service/price path approach to determine the movement of reference tariffs within the access arrangement period.

This approach is permitted by section 8 of the Code and the Commission concludes that GasNet has satisfied this requirement of the Code.

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 (8.2(b))

The Commission has determined that the allocation of capital and non-capital costs to the various reference tariffs satisfy the Code and should be accepted. It has also determined that the proposed allocation method for the K factor under-recovery and capital raising costs are not appropriate and must be amended (see section 8.1 of this Final Decision). With the adoption of the required amendments the Commission anticipates that this Code principle will be satisfied.

The proportion of total revenue recovered from users of a service is calculated consistent with the principles of section 8 of the Code (8.2(c))

The Commission has been particularly concerned about the allocation of costs between Tariff V and Tariff D users and GasNet's application of peak pricing. The Commission has also considered the proposed matched rebates and prudent discounts and their impact on users across the system. A number of aspects of the tariff and cost allocation proposal require alteration. However, with these amendments the recovery of revenues from users is generally consistent with the principles of section 8 of the Code. The Commission has accepted some aspects of the determination of reference tariffs that are broadly consistent with section 8.

Incentive mechanisms that are incorporated are consistent with the principles of section 8 of the Code (8.2(d))

The Commission has assessed GasNet's proposed incentive mechanism and has determined that it does not fully meet the relevant principles of section 8 of the Code. The Commission requires some changes, most significantly, the adoption of the rolling carryover mechanism for operations and maintenance costs. With the adoption of these amendments, the Commission considers that this aspect of the revised access arrangement will meet the principles in section 8 the Code.

Forecasts are best estimates determined on a reasonable basis (8.2(e))

The Commission has specified a number of amendments to the forecast operations and maintenance costs, other non-capital costs and capital costs for the period 2003 to 2007. It also requires GasNet to amend its volume forecasts (see chapter 7 of this Final Decision) to include more recent events and revised market expectations. In addition, it does not accept the suggestion from GasNet that a 10 per cent warming trend should also be recognised.

The Commission considers that these amendments will result in the revised access arrangement using the best estimates available on a reasonable basis.

Conclusion

A number of amendments have been included in this Final Decision. For example, amendments are required in regard to capital and non-capital costs, benefit sharing mechanism and the rate of return.

The Commission considers that with the adoption of the specified amendments, the reference tariff and reference tariff policy satisifes the factors in section 8.2 and is consistent with the objectives in section 8.1 (applied with reference to section 2.24).

Part C – Non tariff issues

9. Access arrangement information

9.1 Code requirements

The service provider's access arrangement information must contain sufficient information in the opinion of the regulator to:

- enable users and prospective users to form an opinion as to the compliance of the proposed revised access arrangement with the provisions of the Code (section 2.6); and
- understand the derivation of the elements in the proposed revised access arrangement (section 2.6).

According to section 2.7 of the Code, the access arrangement information provided may include any relevant information, but must at least contain the categories of information described in Attachment A to the Code, which is summarised in Figure 9.1 below.

Figure 9.1: Summary of Attachment A information

The information required is divided into six categories:

Category 1: access and pricing principles
Tariff determination methodology; cost allocation approach; and incentive structures.

Category 2: capital costs
Asset values and valuation methodology; depreciation and asset life; committed capital works and planned capital investment (including justification for); rates of return on equity and debt; and debt/equity ratio assumed.

Category 3: operations and maintenance costs
Fixed versus variable costs; cost of services by others; cost allocations, for example, between pricing zones, and cost categories.

Category 4: overheads and marketing costs
Costs at corporate level; allocation of costs between regulated and unregulated segments; cost allocations between pricing zones, services or categories of asset.

Category 5: system capacity and volume assumptions
Description of system capabilities; map of piping system; average and peak demand; existing and expected future volumes; system load profiles and customer numbers.

Category 6: key performance indicators
Industry KPIs used to justify 'reasonably incurred' costs; service provider's KPIs for each pricing zone, service or category of asset.

Indicators used to justify 'reasonably incurred' costs

Under section 2.8 of the Code, information included in the access arrangement information may be categorised or aggregated. The extent to which it may be categorised or aggregated is that which is necessary to ensure that disclosure of the information is, in the opinion of the regulator, not unduly harmful to the legitimate business interests of the service provider, a user or prospective user.

If the regulator is not satisfied that the access arrangement information meets the requirements of the Code, it may require the service provider to make changes to the access arrangement information. Likewise, 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 the inclusion of material which, in the regulator's opinion, if released, could be unduly harmful to the legitimate business interests of the service provider or of a user or prospective user (section 2.30).

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 reasonable time to make the changes and to resubmit the access arrangement information.

This chapter relates specifically to access arrangement information provided for users and prospective users. The regulator also has wider information gathering powers under the GPAL. That Law gives the regulator power to require a person to give the regulator information or a copy of a document. The power can be exercised if the regulator has reason to believe that a person has information or a document that may assist the regulator in the performance of any of the regulator's prescribed duties under the Law. Section 2.8 of the Code states that nothing in that section limits the regulator's power under the Law to obtain information, including information in an uncategorised or unaggregated form. The Code and the Law place separate limitations on the regulator's discretion to disclose information received that has been identified as being of a 'confidential or commercially sensitive nature'.

These statutory powers aside, the Commission values the cooperation of service providers and other interested parties in making information available in response to the numerous queries that inevitably arise in considering complex matters.

9.2 Current access arrangement information

When the Commission approved the PTS and WTS access arrangements in 1998 it concluded that the accompanying access arrangement information, as amended and supplemented, satisfied the requirements of sections 2.6 and 2.7 of the Code and sufficient data with respect to all the categories listed in Attachment A to the Code had been provided. This information is available from the Commission's website (www.accc.gov.au).

9.3 GasNet proposal

GasNet submitted revised access arrangement information in support of its proposed revised access arrangement. In addition, it provided a detailed supporting submission which included nine schedules and 12 annexures. Of these, GasNet initially claimed confidentiality for seven annexures but subsequently agreed that six should be released publicly. In addition, GasNet provided additional clarification and information in the form of Errata and information regarding the Murray Valley Pipeline. This information is available from the Commission's website (www.accc.gov.au).

9.4 Submissions to Issues Paper

A number of parties reported difficulties in understanding the information provide by GasNet in either general terms or specifically with respect to the derivation of the elements of the proposed revised access arrangement or in forming an opinion as to its compliance with the provisions of the Code.[585]

TXU stated that it found the approach taken by GasNet of providing most of its supporting information in a separate submission with additional schedules and annexures to be 'particularly complex' and suggested that GasNet should resubmit its application in a simpler and clearer form that substantiates the proposed changes.[586]

ENERGEX believed that it was not possible to understand the relationship between the GasNet and VENCorp access arrangements without access to the SEA and that it should be made publicly available.[587] ENERGEX also requested that non-financial information relating to arrangements between GasNet and incumbent retailers with respect to the WTS be made available. Further, ENERGEX considered that the absence of historic data on operations and maintenance expenditure makes it 'difficult, if not impossible for participants to make cogent assessment of the veracity of the substantive proposals for price increases'.[588]

BHP Billiton requested that the Commission review the adequacy of the access arrangement information provided by GasNet pursuant to section 2.30(b) of the Code. Similarly, TXU stated that it believes that GasNet has not satisfied the requirements of sections 2.6 and 2.7 of the Code, and suggested that the Commission 'request GasNet to resubmit its access arrangement'.[589] The EUAA also requested that the Commission review the adequacy of the access arrangement information provided by GasNet in relation to sections 2.6 and 2.7 of the Code.[590] BHP Billiton and EUAA also requested that the Commission review GasNet's confidentiality claims regarding annexures to its submission.

9.5 Draft Decision

The Commission noted in its Draft Decision that GasNet provided extensive documentation in support of its proposed revisions. It also acknowledged the difficulties expressed by interested parties in understanding the application. These difficulties were considered to reflect the large number of revisions proposed by GasNet and their complexities. However, the Commission was concerned that the format adopted by GasNet added to these difficulties. It suggested that it would be preferable if the proposed revised access arrangement information could be read as a

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585 TXU submission, 3 May 2002, pp. 1-2; ENERGEX submission, 9 May 2002, p. 6; BHP Billiton submission, 17 May 2002, pp. 3-8.

586 TXU submission, 3 May 2002, p. 1.

587 ENERGEX submission, 9 May 2002, p. 6.

588 ibid., p. 6.

589 TXU submission, 31 May 2002, p. 39.

590 EUAA submission, 4 June 2002, pp. 1-2.

stand-alone document. In practice it must be read along with GasNet's submission (including its schedules and annexures) as it contains information needed to allow a reasonable assessment of the proposals. The Commission commented that the Code makes no specific provision that access arrangement information be provided in a single document. The Commission proposed to accept the inclusion of access arrangement information in two documents for the purposes of the Draft Decision. The Commission suggested that GasNet could consolidate this information. Otherwise, its documents would be considered to together form the access arrangement information.

The Commission also expressed concern that parties had reported difficulties in understanding aspects of GasNet's proposals. These difficulties have been evident from misunderstandings expressed in submissions about GasNet's proposals.

The Commission considered this suite of documents in its assessment of the access arrangement information's compliance with the provisions of the Code on its own volition (section 2.30(a)) and in response to BHP Billiton's request (section 2.30(b)) and formed the view that the following information may be needed to satisfy the requirements of sections 2.6 and 2.7 of the Code:

- addition of KPI information in terms of operations and maintenance costs/TJ/km;
- historical operations and maintenance expenditure (for the first access arrangement period); and
- data in support of GasNet's proposed inclusion of the Murray Valley Pipeline in its asset base.

The Draft Decision noted that this assessment had required the Commission to consider the level of detail needed to satisfy the condition of the Code that the access arrangement information should contain sufficient information to allow users and prospective users to understand the derivation of the elements of the access arrangements and to form an opinion as to whether the proposed revised access arrangement would comply with the provisions of the Code.

GasNet queried the need to provide additional access arrangement information. Primarily at issue was whether service providers only need to provide sufficient information to allow users and prospective users to understand the methodology used (for example, allocation of costs), or whether users and prospective users are given sufficient financial data to allow them to replicate the service provider's tariff calculations. The Commission noted in its Draft Decision that it considers that the Code does not require the service provider to provide publicly sufficient information to enable users and prospective users to replicate the service provider's tariff calculations. It does, however, require that the regulator be able to replicate these calculations. Sufficient information was provided to the Commission to form this assessment. It also requires that users and prospective users be able to form an opinion as to compliance with the provisions of the Code.

The need for additional KPI data was discussed in section 10.2.5 of the Draft Decision and an amendment was proposed. GasNet provided data in relation to the Murray Valley Pipeline to the Commission on 1 August 2002. The Commission considered whether to delay release of the Draft Decision in order to allow additional time for interested parties to comment on this information. However, while the Commission noted that the information is important, it was cognisant of the need to expedite the review process. It recommended that interested parties consider the additional information carefully when responding to the Draft Decision.

The Commission considered concerns raised by ENERGEX that the following information has not been disclosed: the SEA; certain information relating to the WTS; and historic data on operations and maintenance. The Commission noted that the SEA is publicly available from its website and that it expected that a revised version would be similarly available once details regarding the WTS have been incorporated (see section 11.1 for discussion of GasNet's services policy). However, it was not aware of any basis under the Code for pursuing ENERGEX's request for disclosure of non-financial information relating to arrangements between GasNet and incumbent retailers with respect to the WTS.

The Commission noted in the Draft Decision that it shares ENERGEX's concerns about the difficulty that interested parties would have in reasonably assessing GasNet's tariff proposals in the absence of historic data on operations and maintenance expenditure. Accordingly, it advised GasNet of its view that this information should be publicly available. GasNet responded that it does not consider that this information should be published:

> This data has been provided to the Commission to assist in its evaluation of our forecast operating cost proposal. However we do not believe that this historical data would be useful to the public in forming a view on our proposals. The historical data is not necessarily a useful guide to future costs, and it is certainly not sufficient to make an informed assessment. In fact, it could potentially mislead the public. For example, the historical data does not include certain governance costs which were borne by GPU and not passed through. In addition, GasNet was obliged to reduce its costs temporarily, and in an unsustainable way, in response to very large revenue shortfalls. On balance, we believe the public should be sufficiently informed by our benchmarking and KPI data, and by a comparison of the previous forecast of operating costs 1999-2002 with the new forecast 2003-2007.[591]

Pursuant to section 7.12 of the Code the Commission must not disclose information for which GasNet has requested confidentiality unless it is of the opinion that disclosure would not be unduly harmful to the legitimate business interests of GasNet or a user or prospective user. The Commission noted that GasNet had not claimed that disclosure would unduly harm the legitimate business interests of any party. It considered that interested parties are capable of understanding GasNet's caveats and that disclosure of this information would assist them to form an opinion as to the compliance of the access arrangement with the provisions of the Code. It did not consider that disclosure of the information would be unduly harmful to the legitimate business interests of GasNet or a user or prospective user. It did consider that the information was needed for users and prospective users to form an opinion as to compliance of the revised access arrangement with the provisions of the Code. Consequently, the Commission disclosed this information as part of the Draft Decision.

The Commission also considered BHP Billiton's request that it review GasNet's confidentiality claims regarding seven of the annexures to its submission. As noted earlier, GasNet agreed that six of these should be released publicly. These were placed on the Commission's website in May and June 2002.

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591 GasNet response to Commission, 1 August 2002.

GasNet stated that it considered that release of Annexure 7 (Valuation of Non-Insured Risks, prepared by Trowbridge) could prejudice its dealings with insurance companies if it were made public as it contains information relating to the value of and need for insurance cover of various types. The Commission considered that this report should remain confidential.

GasNet has also provided a range of data as Errata to its submission. These have been included on the Commission's website.

Notwithstanding a general concern raised by a number of parties about the adequacy of the quantity of information provided by GasNet, the Commission noted that GasNet has provided extensive documentation in support of its proposals. This includes some quite detailed schedules (such as schedule 5 to its submission, Tariff Methodology).

At the time of the Draft Decision, the Commission concluded that, pursuant to sections 2.30(a) and 2.30(b) of the Code, the information provided by GasNet in its access arrangement information and submission generally satisfied the requirements of sections 2.6 and 2.7 of the Code. However, it considered that GasNet's historical operations and maintenance costs should be included in the access arrangement information as this would assist users and prospective users to form an opinion as to the compliance of the access arrangement with the provisions of the Code. An amendment was proposed accordingly.

The Commission's Draft Decision also noted that inclusion of additional KPI data would assist interested parties to form an opinion on compliance (refer section 10.2 of this Final Decision). It was also noted that GasNet would need to submit revised access arrangement information as a consequence of amendments required to its revised access arrangement.

9.6 Response to Draft Decision

GasNet provided amended access arrangement information as proposed in the Draft Decision. However, GasNet does not agree that its submission comprises part of its access arrangement information. It stated that it considers that its draft access arrangement information is a stand alone document that 'contains all the information required by users to determine whether the tariffs comply with the Code'.[592] It described its submission as providing a detailed explanation of the content of, and principles underlying, the proposed access arrangement and access arrangement information which is not intended to form part of its access arrangement information. GasNet stated that, if the Commission identifies any specific material which is contained in its submission that the Commission considers should be included in its access arrangement information, it will consider amending its access arrangement information accordingly.

[592] GasNet submission, 20 September 2002, p. 39.

A number of parties expressed the view that GasNet's access arrangement information continued to be inadequate.[593] In particular, the view was expressed that sufficient information should be disclosed for interested parties to be able to replicate tariff calculations. For example, BHP Billiton noted the requirement under section 2.24(f) for the regulator to take into account the interests of users and prospective users and the requirement under section 3.2(b) for users and prospective users to be able, to the extent practicable and reasonable, to obtain a service which only includes wanted elements.[594] BHP Billiton suggested that, together, these provisions meant that 'users and prospective users must be able to replicate their tariffs to establish that they are fair, reasonable, efficient and cost reflective'.[595]

BHP Billiton commented on a number of specific areas in which it considers inadequate information has been provided. For example, it contended that GasNet has not provided a detailed breakdown of operations and maintenance costs over the first access arrangement period which it states was required by the Commission.[596]

9.7 Final Decision

The Commission has considered the suggestion that the provisions of sections 2.24(f) and 3.2(b) together mean that users and prospective users must be able to replicate GasNet's tariffs. As discussed elsewhere in this document, a regulator must give weight to each of factors specified in section 2.24 as fundamental elements when exercising discretion. However, the provisions of section 3.2 relate specifically to the principles with which a services policy must comply. Provisions relating to access arrangement information are included in section 2 and Attachment A of the Code, which were discussed earlier.

The Commission remains of the view expressed in its Draft Decision that the Code does not require the service provider to provide sufficient information to enable users and prospective users to replicate the service provider's tariff calculations.[597]

The Commission has also considered specific issues raised in submissions, such as BHP Billiton's contention that the Draft Decision required GasNet to provide a detailed breakdown of historical operations and maintenance costs. The Commission notes that proposed amendment 29 of the Draft Decision stated that GasNet must amend section 3.5 of the access arrangement information to include actual historical operations and maintenance costs for each of the years 1998 to 2001, and current best estimates for 2002. GasNet provided these data on 10 September 2002 and they were placed on the

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[593] For example, BHP Billiton submission, 11 October 2002, p. 3; Amcor and PaperlinX submission, 10 October 2002, p. 3; EUCV submission, 9 October 2002, pp. 1-2; EUAA submission, 20 September 2002, pp. 2-3.

[594] BHP Billiton submission, 13 September 2002, p. 4.

[595] ibid.

[596] BHP Billiton submission, 11 October 2002, pp. 6-7. BHP Billiton refers to ACCC, Draft Decision, 14 August 2002, p. 85 and to a meeting with Commission staff which was held on 9 September 2002.

[597] The Commission has verified the calculation of the reference tariff using financial models provided by GasNet on a confidential basis.

Commission's website.[598] However, the Commission did not require a 'detailed breakdown' of historical operations and maintenance costs as suggested by BHP Billiton. It appears that BHP Billiton may have misconstrued the Commission's requirement for public provision of an 'itemised breakdown' of access arrangement review costs incurred in 2001 and 2002.[599] GasNet provided this information to the Commission in October 2002 and it has been placed on the Commission's website.

When the Commission reviewed the adequacy of GasNet's access arrangement information at the time of its Draft Decision, it concluded that the information provided in the access arrangement information document and the information provided by GasNet in its submission were relevant to its assessment of the adequacy of the access arrangement information under section 2.30 of the Code. GasNet has advised that these are two separate documents and that it would consider including specific items of information currently included in the submission in the access arrangement information document if requested by the Commission.

Following these comments from GasNet, the Commission has reconsidered the compliance of the access arrangement information with the Code requirements. The Commission has concluded that GasNet's access arrangement information document, when considered on a stand-alone basis, does not fully satisfy the requirements of section 2.6 of the Code. For example, a breakdown of the revenue requirement for the second access arrangement period (by return on assets, depreciation and non-capital costs) and details of target and forecast revenue are only included in the submission.[600] The Commission considers that this information is required to enable users and prospective users to understand the derivation of the elements in the proposed revised access arrangement and to form an opinion as to the compliance of the proposed revised access arrangement with the provisions of the Code.

Both the access arrangement information and GasNet supporting submission are readily available to interested parties. The Commission considers that little, if any benefit, would accrue to users, prospective users or end-users if it were to require GasNet to amend its access arrangement information to include information available in its submission. Further, such a requirement would risk delaying the approval process and create uncertainty and potential costs for GasNet, users and prospective users. This would not be in the interests of GasNet (section 2.24(a) of the Code), users or prospective users (section 2.24(f)), or be in the public interest (section 2.24(e)). After considering these factors, the Commission has decided not to require GasNet to amend its access arrangement information to include information available in its submission.

As noted in the Draft Decision, GasNet will need to submit revised access arrangement information as a consequence of the amendments required by the Commission in this Final Decision. The Commission understands that GasNet will also submit an amended version of its submission which is consistent with its amended revisions. Pursuant to section 2.30 of the Code, the Commission may at that stage assess whether the access

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598 GasNet, Proposed amendments to revised access arrangement and draft access arrangement information, 10 September 2002, pp. 2-3.

599 ACCC, Draft Decision, 14 August 2002, p. 85.

600 GasNet submission, 27 March 2002, p. 104.

arrangement information as amended satisfies the requirements of section 2.6 and decide whether GasNet should make changes to the access arrangement information.[601]

Amendment 39

GasNet must amend section 3.5 of the access arrangement information to include actual historical operations and maintenance costs for each of the years 1998 to 2001, and current best estimates for 2002.

The Commission has concluded that GasNet must revise its access arrangement information so that it is consistent with the amended revisions. Revised access arrangement information must be provided by 2 December 2002. The Commission will then decide whether further amendments are required to the access arrangement information before approving the revisions.

601 The Commission may decide to require changes at any time after receipt of access arrangement information before its decision to approve revisions to an access arrangement (section 2.30 of the Code).

10. Performance and incentives

10.1 Incentive mechanisms

10.1.1 Code requirements

Section 8.44 of the Code provides for the regulator, wherever it is deemed appropriate, to require or approve an incentive mechanism. An incentive mechanism enables a service provider to retain some or all of any returns from the sale of a reference service that exceed the expected level of returns. The Code provides for an incentive mechanism to operate during an access arrangement period, or during a period incorporating two or more access arrangement periods. This mechanism is to operate where the increased returns are attributable, at least in part, to the service provider's efforts.

Section 8.46 states that an incentive mechanism should be designed to encourage the service provider to increase sales volumes, minimise costs, develop new services and undertake only prudent new investment and non-capital expenditure. The mechanism should be designed to ensure that users gain from any increased efficiency, innovation and improved sales volumes. The mechanism may include:

- specifying the tariff that will apply during the access arrangement period based on forecasts of all relevant variables, regardless of the realised value of those variables;
- specifying a target for revenue and specifying how revenue in excess of this is to be shared between the service provider and users; and
- establishing a rebate mechanism for rebateable services that does not provide a full rebate to users.

10.1.2 Current access arrangement provisions

Provisions relating to incentive mechanisms for the PTS are currently in chapter 9 of the Tariff Order. There are similar provisions in clause 5.3.7 of the WTS access arrangement.

The Tariff Order regulates the pricing of tariffed services and excluded services to be provided by TPA (now GasNet) and other persons in the Victorian gas industry. Section 9.2 of the Tariff Order places limits on the Commission (and other relevant regulators) in its determination of the tariffs to apply in the subsequent (that is, second) access arrangement period. Clause 9.2(a) of the Tariff Order states that the following fixed principles apply to incentives:

> (1) Adopt incentive based regulation using a CPI-X approach (not rate of return regulation);
>
> ...
>
> (4) Ensure a fair sharing of benefits between the service provider and users of the benefits achieved through efficiency gains if, in the initial regulatory period, the service provider has achieved efficiencies greater than the value implied by the X factor used in the initial regulatory period. In ensuring a fair sharing of benefits, the service provider may have regard to the following matters without limitation:

(A) The need to offer the service provider a continuous incentive to improve efficiencies both in operational matters and in capital investment;

(B) The desirability of rewarding the service provider for efficiency gains, especially where those gains arise from management initiatives to increase efficiency;

...

(7) the Regulator may choose to share the benefits achieved in the first regulatory period both in the subsequent regulatory period and in subsequent access arrangement periods; and

(8) the Regulator may issue statements of regulatory intent relating to the proposed benefit sharing mechanism.

10.1.3 GasNet proposal

In its initial submission, GasNet stated that there is a limited role for benefit sharing in both the first and subsequent periods for capital expenditure. This is because, unlike gas distribution businesses, GasNet's capital expenditure tends to be lumpy, well defined and confined to a small number of projects. Consequently, GasNet proposes no carryover in the second period for any capital expenditure efficiencies achieved in the first access arrangement period.

For operating costs, GasNet proposed a carryover of benefits achieved in the first access arrangement period into the second access arrangement period. Under this approach operating cost efficiency savings are calculated as the difference between the original forecast of operating costs for the year 2002 and the average of approved operating cost forecasts (in real dollars) for the second access arrangement period. For the purposes of making this calculation, GasNet adjusted the operating cost forecasts for the second period to exclude regulatory review costs, the increase in insurance costs and Esso litigation costs. It also adjusted the forecast for the last year of the first period to reflect additional workload, inflation, and an adjustment for regulatory expenses. The total efficiency benefit using this methodology is calculated to be $2.22 million. GasNet then determined the net present value of these savings in perpetuity, and a proportion of this value (20 per cent) was added to the proposed allowed revenue over the second access arrangement period. This resulted in the addition of a total of $5.4 million (in 2003 dollars) across the second period.[602]

In relation to operating cost efficiency benefits achieved in the second access arrangement period, GasNet proposed the adoption of the same framework put forward for first period operating cost efficiency gains. Operating cost efficiencies achieved in the second access arrangement period would be calculated as the difference between forecast operating costs approved for the last year of the second access arrangement period and average operating costs approved for the third access arrangement period. The NPV of calculated efficiency gains distributed in perpetuity was to be multiplied by S, a specified sharing ratio. GasNet did not specify a value for S, but stated that actual conditions faced by GasNet, including the ageing of the pipeline system and the changes in workload, should be taken into account when determining the value of S in the future.[603]

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[602] GasNet submission, 27 March 2002, pp. 99-100.

[603] GasNet access arrangement, 27 March 2002, p. 10-11.

10.1.4 Submissions to Issues Paper

BHP Billiton agreed in its submission that there should be an incentive system in place to encourage an improvement in the performance of the regulated assets. However, it contended that efficiency gains achieved by GasNet rightly belong to the users, and thus the greater share of the benefits achieved by the company should accrue to the user. BHP Billiton stated that it is inappropriate for the incentive mechanism put forward by GasNet to reward asset owners for the upside, but not subject them to any of the risk of under-runs in performance. BHP Billiton stated that the mechanism proposed by GasNet for future periods needs to be debated more fully with more information provided by GasNet.[604]

With regard to efficiencies achieved in the first period, BHP Billiton suggested that the approach put forward by GasNet is questionable and avoids the purpose of incentive regulation. BHP Billiton asserted that GasNet should provide information as to the actual savings made in the first period, calculated as the difference between the actual recorded costs and the amount for operations and maintenance costs that were allowed in the current period.[605] The approach to incentives adopted by the ESC for the first period was strongly supported by BHP Billiton.[606]

Amcor and PaperlinX noted that the mechanism put forward by GasNet allows the company to take all of the benefits from efficiency gains while all losses are passed onto users. They suggested that GasNet should be provided with incentives for out-performance, but that only a proportion of gains should be retained, and losses should be shared. Amcor and PaperlinX also support the approach adopted by the ESC.[607]

TXU submitted that GasNet's proposal to calculate efficiency gains against forecast expenditure may result in GasNet not sharing gains with users, and that the adjustment of forecast costs for additional workload may not be appropriate. TXU argued that the approach adopted by the Commission should be consistent with the ESC's approach to efficiency gains.[608]

Similarly, the EUAA submitted that the ESC's approach to efficiencies put forward in the decision on electricity distribution pricing offers a reasonable approach to the share of efficiencies going to users. The EUAA also stated that efficiency gains resulting from capital expenditure and staff time appropriately belong to users:

> Because the users ultimately take all of the direct risk between cause and effect, there can be no doubt that the greater part of the benefits arising from good performance of the asset owner should accrue to the user. Where the asset owner takes the direct risk for improvements, then the asset owner should reap the benefits of such actions. GasNet's submission appears to seek funding for staff and capex to enhance the performance of the GasNet assets. As users will provide this funding, the larger part of the benefits should accrue to users.[609]

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604 BHP Billiton submission, 21 June 2002, pp. 21-22.

605 ibid., pp. 41-42.

606 ibid., p. 21. The ESC approach is discussed later in this decision.

607 Amcor and PaperlinX submission, 24 June 2002, p. 19.

608 TXU submission, 31 May 2002, p. 36.

609 EUAA submission, 11 July 2002, p. 11.

10.1.5 Draft Decision

Benefit sharing for subsequent periods

The Draft Decision noted that the proposal put forward by GasNet for capital expenditure does not allow for the carryover of efficiency gains (losses) in the subsequent access arrangement period. This approach, however, does provide some incentives for efficiencies. This is because capital expenditure forecasts are incorporated in the revenue model at the start of an access arrangement period, resulting in GasNet effectively keeping for the remainder of the access arrangement period the finance cost savings of any capital expenditure efficiencies achieved. A mechanism that does not allow a carryover of efficiency gains (losses) is known as a P_0 approach.

On the basis of the information available, the Commission stated that it considered GasNet's proposal to be appropriate for capital expenditure savings (losses) achieved. This was because the methodology provided some incentive for efficiency savings, while at the same time limited the incentive for GasNet to overforecast capital expenditure at the start of an access arrangement period. GasNet faces an incentive under any benefit sharing mechanism to overforecast capital expenditure, given that it keeps the finance cost savings of any overforecast achieved. This behaviour is difficult to observe given its lumpy, inconsistent nature. However, the Commission considered that a P_0 mechanism should limit this incentive while at the same time encourage some productivity improvements. The Draft Decision noted that further research in this area was warranted.

With regard to operations and maintenance expenditure, the Commission stated in the Draft Decision that it considered that the proposal put forward by GasNet did not represent an appropriate benefit sharing scheme. The Commission stated that it regarded the mechanism proposed by GasNet to be inadequate on a number of grounds:

- it does not provide a continuous incentive for efficiency improvements. Specifically, there may be an incentive under this regime for GasNet to defer the implementation of operating cost efficiencies achievable at the end of the current period until the start of the subsequent access arrangement period, or even increase expenditure at the end of the current period in order to substantiate higher forecasts in the subsequent period;
- it does not encourage the revelation of underlying efficient costs;
- it does not consider temporary efficiency gains/losses that may have been achieved by GasNet within the period. The Commission's view is that benefits and losses should be shared with users regardless of whether they are temporary or permanent, and that it is difficult to distinguish between what constitutes temporary and permanent efficiency savings (losses);
- the mechanism proposed by GasNet is likely to understate the share of benefits it receives. This is because it excludes the benefits (losses) achieved within the initial period, which would generally be included in efficiency calculations;
- the model is asymmetric in that only efficiency gains, not losses, can be carried forward. This characteristic is problematic as it provides an incentive for inefficient behaviour; and

- when calculating the NPV, the model inappropriately assumes that the life of the asset is infinite.

The Commission considered that the approach known as the rolling carryover mechanism provides a more appropriate incentive structure. This mechanism had been proposed by the ESC for the Victorian electricity and gas distribution businesses. The following discussion was included in the Draft Decision and outlines the rolling carryover mechanism and the Commission's specific application of this benefit sharing scheme.

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 expenditure minus the reduction (increase) in expenditure anticipated for that year at the start of the previous access arrangement period.[610] 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.

To illustrate, consider a service provider that has operating cost forecasts and actuals as denoted in Table 10.1. 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 through subtracting the forecast reduction in costs between year one and year two ($0) from the actual reduction in costs that occurred between these years ($10). Calculated the same way, the firm achieved an additional $5 of unanticipated gains between year two and year three, and again between year three and four it achieved $5 of unanticipated gains. In this example, the regulator determines that the cost forecasts for the second period to be $80 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.[611] After that time the allowable revenues for operations and maintenance

[610] ORG, *2003 Review of gas access arrangements: consultation paper no.1 – issues for consultation*, May 2001, p. 96.

[611] 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 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.

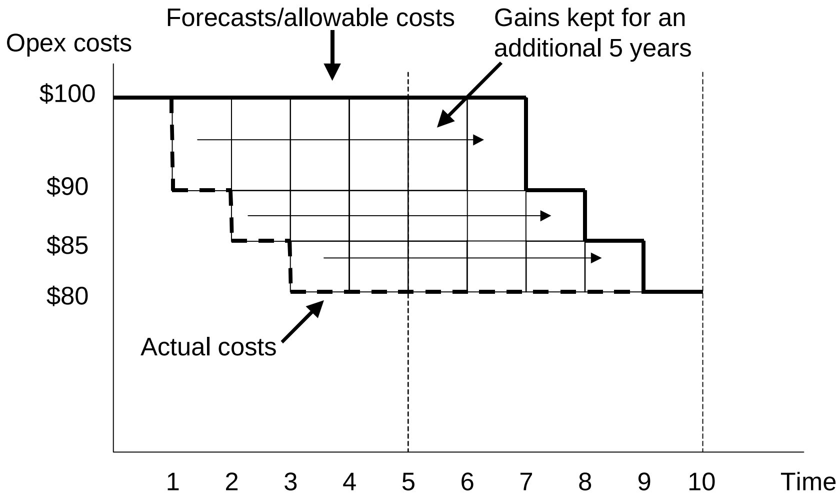
expenditure are reduced to correspond with the forecasts made at the beginning of the subsequent regulatory period.

This example of the rolling carryover mechanism is illustrated in the following table and figure.

Table 10.1: 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

Figure 10.1: Illustration of the rolling carryover mechanism



Benefits of the rolling carryover mechanism

Many of the problems associated with the GasNet approach to benefit sharing are overcome through the implementation of the rolling carryover mechanism. Firstly, the rolling carryover mechanism provides an ongoing incentive for efficiency gains throughout an access arrangement period. Given that efficiency gains achieved in one year are kept for the same length of time as gains obtained in any other year, it will always be in the interests of a profit-maximising service provider to introduce efficiency projects as soon as possible because of the time value of money. This property of the rolling carryover mechanism is recognised by GasNet, which notes that the ESC model 'has the theoretical advantage of providing a consistent incentive to improve in each year of an access arrangement'.[612]

Another advantage of the rolling carryover mechanism is that there is no need to distinguish between temporary and permanent efficiencies because all gains as well as losses achieved by the service provider are shared with users.

A third advantage of the rolling carryover is that there is greater transparency over the setting of the distribution of benefits. Under this mechanism, the number of years that the service provider can retain operating cost efficiencies, and thus the sharing of benefits, can be set on an ex ante basis. This compares to other mechanisms, including the proposal put forward by GasNet, where information pertaining to the actual distribution of benefits is only available ex post.

612 GasNet submission, 27 March 2002, p. 100.

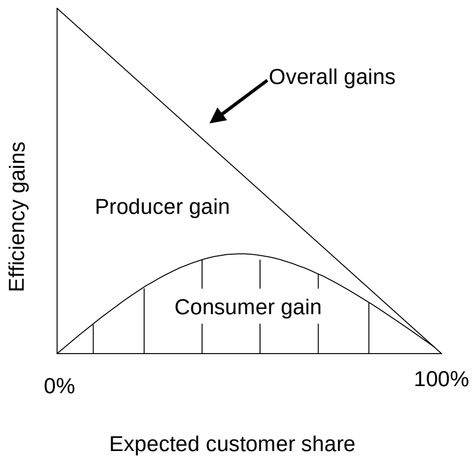
A fourth benefit is that by providing an ongoing incentive for least cost operation, it encourages the firm to reveal its underlying costs.[613] This important characteristic of the rolling carryover model is discussed in detail later in this chapter.

Distribution of benefits

As noted above, under the rolling carry over incentive mechanism the distribution of efficiency benefits between the service provider and users can be determined on an ex ante basis. It is suggested that there is a trade-off between the distribution of unanticipated gains to the service provider and economic efficiency.[614] It is argued that the productivity of the service provider will be higher when the firm's share of the benefits are greater. This is because the firm is more likely to implement risky efficiency generating projects when the expected payoff to the firm of introducing these projects is higher.

The Commission noted in the Draft Decision that it was not aware of any empirical studies undertaken to assess the optimal distribution of benefits, although a number of theoretical arguments have been put forward. An analysis undertaken by NERA suggests that a 50 per cent sharing may maximise user gains. This conclusion is based on the assumption that there is a proportional relationship between efficiency gains and user share. That is, if the firm is able to keep 50 per cent of any benefits achieved, then half of all potential efficiencies will actually be implemented.[615] The following figure illustrates the NERA hypothesis.

Figure 10.2: The trade off between efficiency and the distribution of gains



Source: NERA, Incentives and commitment in RPI-X regulation, October 1997, p. 11.

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[613] ORG, *2003 Review of gas access arrangements: consultation paper no.1 – issues for consultation,* May 2001, p. 93.

[614] NERA, *Incentives and commitment in RPI-X regulation*, October 1997; S King, 'Principles of price cap regulation', *Infrastructure regulation and market reform, principles and practice: selected papers prepared for the utility regulation training program,* November 1997; ORG, *Electricity distribution price determination 2001-2005 volume 1: statement of purpose and reasons,* September 2000.

[615] NERA, *Incentives and commitment in RPI-X regulation,* October 1997, p. 11.

Others argue that an equal sharing of benefits between the firm and consumers may not be the most appropriate distribution. In an article noted by the ESC, UK-based consultants OXERA purport that in the majority of cases the optimal share remains in the range of 40-60 per cent for the firm, depending on the form of the relationship assumed between incentives and gains.[616] The ESC suggests that a sharing mechanism that gives the firm approximately 30 percent of unanticipated gains will provide sufficient efficiency incentives for productivity improvements.

This argument for a 30 per cent sharing made by the ESC is based on the notion that the relationship between productivity gains and consumer distribution is concave. That is, as the share of gains (losses) retained by the firm increases, productivity improvements are proportionately higher initially, but fall off quickly. It is argued by the ESC that this represents an appropriate assumption as the idea that efficiency gains fall with further incentives is consistent with diminishing returns. [617]

The Commission concurred in its Draft Decision with the ESC's assessment in its draft decision regarding the electricity distributors.[618] It considered that a distribution of operating cost efficiency savings of approximately 30 per cent to the service provider is appropriate as it should provide sufficient incentives to the firm to implement productivity improvements. A sharing of approximately 30 per cent is achieved through allowing a service provider to maintain unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years.[619]

Equal treatment of gains and losses

The Commission stated in its Draft Decision that unanticipated losses (overruns) should be treated the same as gains in the rolling carryover mechanism. Only then will the mechanism function smoothly. To illustrate, consider a firm that faces constant costs over the length of a regulatory period that corresponds with forecast costs. Under a mechanism that does not require the retention of losses, the service provider has an incentive to claim a gain in one year, and to shift expenses to the following year and claim a loss. Through this strategy, the firm is allowed to maintain the reported benefit for six years, but only has to bear the reported loss during the year that it occurs. An example of this gaming opportunity is illustrated in the following table.

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616 ORG, *Electricity distribution price determination 2001-2005 Volume 1: statement of purpose and reasons*, September 2000, p. 92.

617 ibid., p. 93.

618 A similar approach was also adopted for Gas in Victoria. See ESC, *Final Decision: review of gas access arrangements*, October 2002.

619 This calculation is based on a real vanilla WACC of 6.4 per cent.

Table 10.2: Example of an asymmetric rolling carryover mechanism

	$								
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Forecast	100	100	100	100	100				
Reported	80	120	100	100	100				
Year to year efficiency	20	-40	20	0	0				
Yr 1 efficiency carryover		20	20	20	20	20	0		
Yr 2 efficiency carryover			0	0	0	0	0		
Yr 3 efficiency carryover				20	20	20	20	20	0
Total efficiencies retained by firm	20	-20	40	40	40	40	20	20	0
Actual change in cash flows	20	-20	0	0	0	40	20	20	0

The example illustrates that the service provider can earn an additional cash flow of $80 in nominal terms by adjusting the timing of costs when asymmetry exists in the rolling carryover mechanism. This behaviour is not efficient – users would have to carry these additional costs through unnecessary higher prices.

Consequently, the Draft Decision concluded that the incentive mechanism operating for GasNet should incorporate both losses and gains. A symmetrical approach should remove any incentive for GasNet to game the Commission through expenditure adjustments. Under the proposed approach, GasNet is only subject to 30 per cent of any losses incurred through the course of an access arrangement period.

Uncontrollable gains and losses

Uncontrollable gains (losses) are cost savings (losses) that result from factors outside of the firm's control, such as the weather or general economic conditions. Incentive mechanisms have no impact on these outcomes. Accordingly, in theory the firm should not be rewarded or penalised for uncontrollable events.

However, in practice the separation of uncontrollable gains (losses) from controllable gains (losses) is often very difficult. In order to distinguish between these costs, the Commission would have to undertake a significant and detailed analysis of company expenditures at each scheduled review of the access arrangement. Such analysis would be resource intensive for all parties involved and may not generate appropriate information to allow a robust benefit sharing mechanism to operate. Moreover, even if it is established that specific costs were the outcome of events outside of the firm's control, the service provider may have been able to mitigate the consequences. For example, a firm can protect itself from input price increases through the use of financial instruments such as futures contracts.

Given these difficulties, the Commission stated in the Draft Decision that it considers it to be more appropriate and practical that no distinction is made between controllable and uncontrollable gains (losses) in applying the rolling carryover mechanism.

Adjustment for changes in volumes

The Commission stated that it considers that the calculation of efficiency gains (losses) should not involve adjustments for differences between forecast and actual volume growth within the access arrangement period. This is because the variable or marginal cost associated with an increase in volumes is likely to be negligible for a transmission pipeline network. Also, an increase in volumes is a commercial decision. If a service provider considers ex ante that the revenue associated with an increase in volumes exceeds the costs associated with additional volume growth, then a profit maximising service provider will allow for this volume growth and will be rewarded for any resulting profits. If the service provider was compensated for any additional costs by users through an adjustment to the calculation of efficiency gains (losses), then it would face distorted ‘prices’ and may therefore make inappropriate decisions that violate allocative efficiency principles.

While the Commission expressed the view in its Draft Decision that volume growth should not be adjusted for, it noted that it would be appropriate to adjust the efficiency mechanism ex post to take into account additional costs associated with capital expenditure deemed prudent and included in the capital base. The service provider could submit relevant information at the time of the next scheduled review, and if deemed appropriate, an adjustment to operations and maintenance expenditure in the previous period could be made for the purposes of calculating the efficiency carryover in the subsequent period.

Treatment of final year expenditure

It was acknowledged in the Draft Decision that at the time that the Commission is to determine reference tariffs for a new period there will be no information available on a service provider’s actual expenditures for the last year of the current access arrangement period. In order to overcome this difficulty, the ESC has suggested that expenditure in the last year of the current access arrangement period be assumed to be the same as expenditure in second last year, less the efficiency gains (losses) assumed in the original forecasts.[620]

If the estimates for expenditure in the final year of the current access arrangement period are used to determine operations and maintenance cost forecasts in the subsequent period, then this treatment of final year costs should have negligible impact on revenues established for the service provider. If the firm achieves an efficiency gain in the last year of the access arrangement period, then there would be no carryover of that unanticipated gain. However, the benchmark determined for the next access arrangement period would be higher by an amount equal to the gain, resulting in the service provider receiving revenues as if the efficiency had been recognised through the carryover mechanism.[621]

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[620] ORG, *2003 Review of gas access arrangements: consultation paper no.1 – issues for consultation*, May 2001, p. 100.

[621] ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 121.

Trend factor

The ESC proposed a mechanism where estimated actuals in 2002[622] are used as a foundation for establishing allowed forecasts of operations and maintenance expenditure in 2003-2007. This approach involves the assessment of the required step in expenditure levels between estimated actuals in 2002 and 2003, and then the application of a percentage trend factor expected over the next period to determine forecast operations and maintenance costs. The ESC proposed that the trend factor reflect assumptions regarding annual productivity gains, cost of inputs and the impact of demand growth, while the step factor incorporates movements in a range of different cost items, such as the impact of full retail contestability, licence fees and insurance premiums.[623]

The Commission stated in its Draft Decision that it agreed in principle with this approach. However, the Commission commented in the Draft Decision that it did not regard this mechanism appropriate for GasNet's forthcoming access arrangement period. This is because GasNet would not have been aware during most of the first access arrangement period of the likelihood of the rolling carryover mechanism model being introduced at this time and so would not be expected to have responded to its incentives in the first access arrangement period.

GasNet may have expected a more traditional benefit sharing approach such as a glide path or a P_0 mechanism to be adopted at this review. Accordingly, its actions during the initial access arrangement period may reflect these expectations. As a result, an equal incentive for least-cost production would not have been provided at all times, and actual operations and maintenance costs achieved by GasNet in the first period may not be cost reflective.

The Draft Decision concluded that the trend and step methodology is not appropriate in the move from the initial access arrangement period to the forthcoming period. However, the Commission considered that a trend approach based on operations and maintenance cost actuals achieved in 2006 is reasonable for the third access arrangement period (expected to be from 2008 to 2012). The adoption of the rolling carryover mechanism for efficiency gains (losses) achieved in the 2003-2007 period should ensure the achievement of efficient operations and maintenance costs in that period, which can be reasonably used as the basis of a step and trend factor adjustment for operations and maintenance cost forecasts in the following period. The Draft Decision noted that details relating to the calculation of the trend and step factors will need to be developed at GasNet's next scheduled review. It suggested that GasNet may elect to include these details in this revised access arrangement.

Conclusion

To summarise, in the Draft Decision the Commission considered that the approach nominated by GasNet for capital expenditure benefit sharing was not unreasonable, but that the mechanism proposed for the calculation of the operations and maintenance costs allowance in the third access arrangement period was not appropriate. The

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622 Estimated using the methodology noted above.

623 ESC, *Draft Decision: review of gas access arrangements*, July 2002, pp. 49-51.

Commission proposed the implementation of the rolling carryover mechanism for operations and maintenance costs. The specific mechanism proposed would allow GasNet to retain efficiency gains (losses) for five years in addition to the year which they are achieved; treats gains and losses equally; and would not distinguish between controllable and uncontrollable gains (losses). The Commission also proposed that actual costs achieved in 2006 be used as the basis for expenditure benchmarks in the third access arrangement period.

The Draft Decision also stated that the benefit sharing carry forward amount should be calculated and distributed in real dollar terms.

Consequently, the Commission proposed an amendment to GasNet's proposed revised access arrangement with the purpose of establishing an appropriate incentive mechanism.

Benefit sharing for the first period

The approach suggested by GasNet for benefit sharing in capital expenditure corresponds with a P_0 mechanism, where all savings (losses) are transferred to users at the start of a new access arrangement period. For the reasons given above, the Commission stated in the Draft Decision that it was satisfied with the application of this approach to capital expenditure savings (losses) achieved in the first access arrangement period as well as the second.

Sharing mechanism

For operations and maintenance expenditure, the previous discussion outlined the merits of the rolling carryover mechanism. However, the Commission stated that the rolling carryover mechanism was not appropriate for the first period. This is because GasNet was not aware of the rolling carryover model and could therefore not respond to it in the first access arrangement period. Also, the approach adopted now cannot influence past behaviour.[624]

It was determined in the Draft Decision that the approach put forward by GasNet for the first period is not reasonable. In principle, the Commission did not oppose the comparison of forecasts between periods to determine the efficiency gain (loss) achieved by the service provider. However, it expressed concern with the distribution of the calculated allowance proposed by GasNet. The GasNet proposal is problematic as it assumes that the asset life is infinite in the calculation of net present values; is likely to understate the share of benefits for GasNet; and may generate an unfair sharing of benefits with users if GasNet benefits from temporary efficiencies not reflected in the measure.

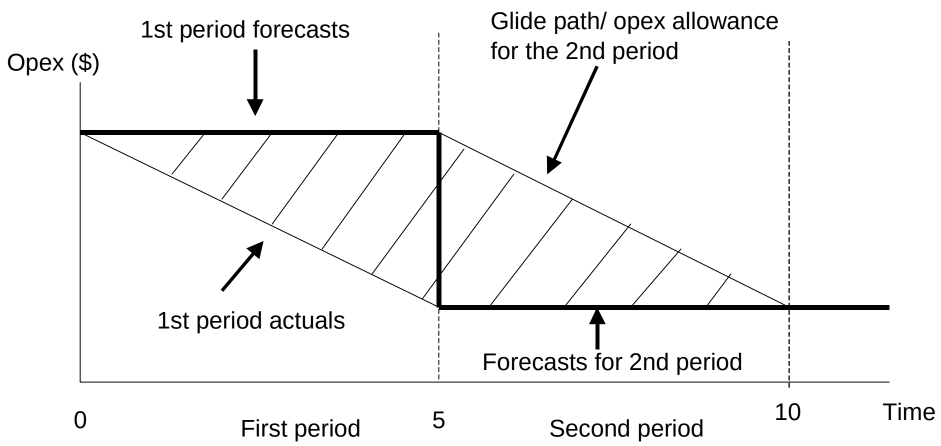
The Commission considered that a glide path mechanism would be more appropriate for operations and maintenance expenditure gains achieved by GasNet in the first access arrangement period. The glide path mechanism was highlighted by the

[624] ORG, *Draft Decision: 2001 electricity distribution price review,* May 2000.

Commission in the DRP and was adopted by the ESC in 2000 for first period efficiency gains achieved by electricity distribution companies.[625]

The Draft Decision outlined the operation of the glide path. It stated that operations and maintenance expenditure forecasts are initially calculated for the subsequent period based on the regulator's determination of efficient costs. These target revenues are then adjusted to allow for any efficiency gains obtained by the firm over the previous period. The benefits (losses) achieved by the company are shared with users in the subsequent period by the gradual reduction of gains (losses) irrespective of their source.[626] In the DRP, the Commission stated that it would be appropriate to implement a glide path for one regulatory period beyond the period in which the efficiency gains accrued, and that a straight-line phase out of efficiency gains would be reasonable for simplicity.[627] Under this approach, any efficiency gains (losses) are incrementally reduced (increased) so that at the end of the period the benefit (loss) has moved to consumers entirely. The following figure illustrates a glide path mechanism as discussed in the DRP.

Figure 10.3: Glide path benefit sharing mechanism



In the above figure, the shaded area in the first period represents the difference between actual and forecast operations costs in that period, while the shaded area in the second period denotes the benefit accrued by the service provider from the glide path adjustment mechanism. The total shaded area represents the net economic profit retained by the service provider.

Measuring efficiencies

The Draft Decision noted that the DRP provides little guidance as to the measurement of efficiency gains for the purposes of a glide path carryover, and there seems to be little discussion of this issue in the literature on incentives. It also noted that the ESC implemented a glide path mechanism for efficiencies achieved in the first period for Victorian electricity distributors. The ESC measured efficiency gains as the difference

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[625] ORG, *Electricity distribution price determination 2001-2005 Volume 1: statement of purpose and reasons,* September 2000, p. 98.

[626] ACCC, DRP, May 1999, p. 90.

[627] ibid., p. 90.

between actual and forecast operations and maintenance costs in 1999 (which was the fourth year in the regulatory period in question). However, the Commission considered that this measurement approach is not appropriate. One reason for not adopting this approach is that year four actuals may not be reflective of actual expenditure undertaken in the fifth year of the first period, and unlike the proposed rolling carryover mechanism, there is no adjustment mechanism in place that addresses changes between year four and five expenditures. It is considered imperative that efficiency gains are measured taking year five actuals into account as year five actuals will provide a better indication of permanent efficiency gains. In addition, the use of year four actuals to calculate efficiencies is only valid if the operations costs achieved through the period followed a relatively straight line from forecasts in year one to those achieved in year five. GasNet achieved significant temporary gains in the first three years of its first period which consumers would not share under the ESC approach to measuring efficiencies for the glide path.

A second method for measuring efficiencies for a glide path is to use the difference between forecasts for the final year of the current period with forecasts for the subsequent period, provided that they are reasonable.[628] This approach overcomes the fifth year information problem associated with the ESC electricity glide path approach, and corresponds with the usual interpretation of a glide path as a gradual movement from the old to new revenue allowance for operations and maintenance costs. This method requires two pieces of information: cost forecasts for 2002 and an average of cost forecasts for the forthcoming period.

For GasNet, the final year forecasts were obtained from the 1998 tariff model which forecasts operations and maintenance costs of $18.75 million for 2002 (nominal dollars).[629] The Commission considered it appropriate to adjust this figure to take into account additional costs associated with new capital expenditure undertaken during the access arrangement period, such as the Interconnect and the Southwest Pipeline, and regulatory expenses budgeted but not levied in the first period. This allows the efficiency carryover calculated through an assessment of comparable forecasts. GasNet stated that this total figure is $18.9 million (in 2003 dollars). In the Draft Decision the Commission assessed this adjustment as reasonable.[630]

With regard to operations cost forecasts for the following period, the Commission outlined what it considered prudent in the Draft Decision. It was noted that the average of operations and maintenance expenditure forecasts was $19.2 million in 2003 dollars.[631] Subtracting the average of second period forecasts from adjusted year five forecasts for the first access arrangement period gave an efficiency loss over the first period of approximately $300 000 (in 2003 dollars). This would require GasNet to be subject to a negative glide path adjustment in the second period.

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[628] This approach to measuring the efficiency achieved in the first period resembles that put forward by GasNet. However, this proposal differs considerably as the Commission's mechanism employs different forecasts to determine the relevant efficiency measure.

[629] TPA access arrangement information, 30 November 1998, p. 8.

[630] GasNet submission, 27 March 2002, p. 99.

[631] It is considered appropriate to calculate efficiency gains (losses) in real terms. This is because the objective of an efficiency mechanism is to reward the service provider for actual productivity/efficiency improvements (impairments) rather than just nominal improvements.

A third approach to measuring efficiencies is to assess the unanticipated gains (losses) obtained by GasNet in the first period. Aggregate operations and maintenance costs achieved by GasNet in 1998-2002 were noted in section 6.1.2 of the Draft Decision. These costs were compared against forecasts for the first access arrangement period to determine the benefit accrued to GasNet in the first period. This analysis concluded that actual operations and maintenance expenditure achieved by GasNet for the period 1998-2001 was substantially less than what was originally forecast. However, by the end of the period actual expenditure is expected to approximately equal that forecast, indicating that the efficiency gains in the first half of the period will have been lost by the end of the period. As there are no ongoing efficiency gains, it was concluded that there is no reason to add an amount for GasNet to the benchmark revenues using this approach. Further, it was noted that given that GasNet has gained from the temporary efficiencies achieved, it could be argued that some of these gains should be shared with users. This would require an amount to be deducted from the benchmark revenues (that is, a negative glide path).

Conclusion

Following the above discussion, the Commission concluded in the Draft Decision that the glide path approach to sharing operations and maintenance cost efficiency gains between GasNet and users is appropriate for first period gains even though the rolling carryover approach is the appropriate approach for future access arrangement periods.

A number of reasonable approaches to the calculation of efficiencies achieved in the first period indicated that there are no permanent efficiency gains for users and GasNet to share. In fact, there are arguments for deducting an amount from the benchmark revenues for efficiency losses and/or to share some of the temporary gains with users. However, the Commission stated that, on balance, it considered that because of the uncertainty relating to the benefit sharing mechanism applying to GasNet at the start of the initial access arrangement period, and the lack of discussion on the treatment of losses, it was unreasonable to deduct revenue from GasNet in the second period for efficiency losses or temporary gains in the first period. Accordingly, the Commission proposed an efficiency carryover of zero to apply in the second access arrangement period in the Draft Decision.

10.1.6 Response to Draft Decision

In its submission to the Draft Decision, GasNet acknowledged that ESC’s five year rolling carryover model has a range of appropriate incentive mechanisms, including a continuous incentive to improve performance each year. However, GasNet argued that the model would penalise the company for cost increases outside of management’s control. It argued that any increase in uncontrollable costs, such as insurance costs, must be borne by GasNet for five years. GasNet interprets the Commission’s position as being that the regulatory system is advantageous to GasNet, ‘since in a price taking market, the service provider would have to bear the loss indefinitely, rather than until the time of the next price reset’. GasNet disputes this, asserting that in a competitive market cost increases would be incurred by all competing entities, and thus prices to consumers would increase.[632]

GasNet argued that certain cost categories should be defined and excluded from the efficiency carryover mechanism. These include cost categories that fall under the pass through mechanism, as well as other costs claimed to be outside of management's control.[633]

With regard to the benefit sharing mechanism for the first period, GasNet submitted that it achieved significant and sustainable efficiency gains in the first period, particularly in the areas of pipeline and compressor maintenance. GasNet has accepted the use of the glide path mechanism for the first access arrangement period, but has not made all the necessary adjustments required for the application for the glide path.[634]

GasNet noted that the Commission makes allowances in the efficiency calculations for changes in the scope of operations experienced by GasNet and the exclusion of regulatory fees budgeted but not levied in first period forecasts. However, GasNet has argued that increases in insurance premiums should also be excluded from the calculations. It observed that these cost increases have been accepted by the Commission as genuine and outside the control of GasNet, and has included any future increases or decreases of these costs in the pass through mechanism. GasNet stated that for consistency these costs should be excluded from the efficiency calculations in the first period, through removing these costs from the forecasts for the subsequent period.[635]

GasNet recalculated the glide path for the first period using the methodology set out in the Draft Decision including an adjustment for the extraordinary insurance increase. According to GasNet, this calculation generates an efficiency carryover in nominal terms of $0.91 million in 2003, $0.73 million (2004), $0.55 million (2005), $0.36 million (2006), and $0.18 million (2007).[636]

In its first submission responding to the Draft Decision, BHP Billiton discussed incentive regulation in its broader context. BHP Billiton claimed that the Commission's assumption that positive incentives for GasNet will always be in the best interests of consumers has not been proven. It asserted that strong competition drives positive outcomes, not financial incentives, and that 'competition by comparison is the only driver which will ensure both short and long term economically efficient outcomes for the regulated provider and for the consumer'.[637]

BHP Billiton referred to a critique of light-handed regulation by Paul Carpenter and Carlos Lapuerta, who assert that light handed regulation has unintentionally created

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[632] GasNet submission, 20 September 2002, pp. 39-40.

[633] ibid., p. 40.

[634] ibid.

[635] ibid., pp. 40-41.

[636] ibid., p. 41.

[637] BHP Billiton submission, 13 September 2002, p. 6.

inefficient incentives for regulated companies; has not constrained the monopoly power of incumbents; and has exacerbated the information disadvantage of regulators.[638]

In its second submission, BHP Billiton reiterated its view that a light-handed regulatory approach will only reward the overstatement of costs. It argued that:

> By not verifying costs on the unproven assumption that regulated businesses will provide an improved service because it gives them long term benefits and that these will flow to users, will simply disadvantage the interests of users and prospective users.[639]

BHP Billiton stated that it agrees with the model of benefit sharing proposed by the Commission in the event that savings are identified. However, it does not concur with the approach proposed by the Commission in identifying benefits, and then limiting the proportion shared with users. BHP Billiton observes that GasNet has claimed some $20 million (or $4 million per annum) in operating cost savings, but claims that these savings were unsustainable, avoiding the need to share them with users.[640]

Amcor and PaperlinX asserted that in the absence of any substantiation of the claim that operating cost savings were unsustainable, the Commission must reject GasNet's proposal and apply an appropriate efficiency saving factor, consistent with the savings achieved in the first period.[641]

In its submission responding to the Draft Decision, the EUCV stated that the Commission's benefit sharing proposal is not appropriate as GasNet has to declare that a saving has been made. By declaring that a saving is unsustainable, GasNet avoids having to share anything with users. The EUCV commented:

> We are clearly of the view that GasNet has been able to sensibly reduce its operating costs from the levels paid for in the current AA [access arrangement], and there is a saving available to be shared with users.[642]

The issue of the K factor was also raised with regard to benefit sharing. The EUCV has argued that one of the reasons for the unsustainable operating cost savings in the first period was the warmer weather conditions, but these costs are already included in the K factor carry forward.[643] The EUCV also argued that the Commission is allowing GasNet to levy users an unreasonable level of operations and maintenance costs for the new access arrangement period and also retain cash that it was provided but never spent.[644]

The EUCV stated that it cannot endorse the proposed approach as it: fails to bring forward real savings; allows GasNet to be paid twice for the same work; and gives GasNet a lump sum payment as a reward for its own poor forecasting.[645]

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638 ibid.

639 BHP Billiton submission, 11 October 2002, p. 5.

640 ibid., pp. 5-6.

641 Amcor and PaperlinX submission, 10 October 2002, p. 2.

642 EUCV submission, 9 October 2002, p. 6.

643 ibid.

644 ibid., p. 7.

645 ibid.

10.1.7 Final Decision

Benefit sharing for subsequent periods

The Commission intends to maintain the approach proposed in the Draft Decision for capital expenditure. The mechanism, which does not allow for the carryover of efficiency gains (losses), provides some incentive for efficiencies, while at the same time constrains the incentive for GasNet to overforecast capital expenditure.

The Commission also intends to maintain the general operations and maintenance costs benefit sharing approach proposed for subsequent periods in the Draft Decision. This approach has a number of distinct advantages over other benefit sharing schemes. As discussed in the Draft Decision, the design of the mechanism provides a continuous incentive for efficiency gains throughout the access arrangement period (consistent with sections 8.46(b) and (e) of the Code); eliminates the need to distinguish between temporary and permanent gains; and encourages the firm to reveal underlying costs. This general approach to benefit sharing is supported by a number of interested parties. GasNet recognises that the model has a range of appropriate incentive characteristics.

However, criticisms both of a general and specific nature were raised regarding the mechanism. Firstly, GasNet asserts that the model penalises GasNet for any cost increases that occur within the access arrangement period which are outside of managements control. Thus, GasNet argues, certain cost categories should be excluded from the efficiency carryover, such as those that are included in the pass through mechanism.

After further consideration, the Commission concurs with GasNet that it is not appropriate to incorporate any approved pass through amounts in the benefit sharing calculation. The inclusion of such pass through events in the model is logically inconsistent. If a positive pass through event was approved within the access arrangement period, this would generate an increase in allowed revenues within the period. If these costs were then included in the benefit sharing calculation at the end of the period, then these costs would effectively be taken away from the service provider for a specific number of years, depending on when in the period the pass through event occurred.

If a pass through event was approved within the period, then the benefit sharing calculation should exclude the associated increase or decrease in costs in that year. For example, if there is a pass through increase of $10 000 in 2004, then benchmark costs in 2004 and subsequent years in that period should also be increased by $10 000. Otherwise the rolling carryover benefit sharing calculation would remove the $10 000 despite the Commission’s approval of it being a pass through.

Similarly, the Commission is of the view that forecast operations and maintenance costs in 2003 should also be decreased by the amount of the review costs for the purposes of calculating the benefit sharing carryover for second period efficiencies. This is because review costs are allowed in benchmark revenues in 2003 but were actually incurred in 2001 and 2002.

The Commission, however, does not agree with GasNet that costs other than pass through or review costs should be excluded from the benefit sharing calculation. While in theory uncontrollable costs should be excluded from a benefit sharing scheme as incentive mechanisms have no impact on these outcomes, in practice it is difficult to make a distinction between which costs are controllable and uncontrollable. The majority of cost increases (decreases) are likely to be the outcome of both controllable and uncontrollable variables, making any categorisation of costs highly problematic. Moreover, to attempt to make a distinction between these costs would require the Commission to undertake detailed analysis of company expenditures, which is contrary to the light handed approach preferred by the Commission.

A second criticism from GasNet with regard to the proposed benefit sharing mechanism centres around a misinterpretation of the Commission's position. GasNet interprets the Draft Decision as stating that GasNet is at an advantage compared to a competitive market where firms have to bear any uncontrollable cost increases indefinitely. Cost increases are passed onto GasNet at a scheduled review. The Commission, however, did not intend such an interpretation of the Draft Decision. The Commission recognises that in a competitive market uncontrollable cost increases would be incurred by all competing firms and passed onto consumers. The reason the Commission has incorporated uncontrollable costs in the benefit sharing model is that, as discussed in the Draft Decision, it is difficult in practice to distinguish between different cost categories.

A third criticism of the benefit sharing approach proposed by the Commission is that the approach requires GasNet to declare that a saving has been made. It is argued by the EUCV that GasNet avoids having to share anything with users by declaring that a saving is unsustainable. It should be noted that the calculation of the carryover for second period gains is a mechanistic process whereby the benefits (losses) are measured as the difference between actual costs achieved and benchmarks. This eliminates the need to distinguish between temporary and permanent gains.

The Commission notes that despite general acceptance of the benefit sharing approach, BHP Billiton criticises the Commission's assumption that positive incentives will always be in the best interests of consumers. BHP Billiton argues that light-handed regulation has not constrained the monopoly power of service providers; has exacerbated the information disadvantage of regulators; and has created inefficient incentives for regulated companies. The Commission notes that the adoption of incentive regulation is a policy issue that is permitted under specific provisions of the Code. It would therefore be inappropriate to address these broad regulatory issues within the context of this review. Moreover, the Commission considers that the benefit sharing mechanism to apply in subsequent periods balances the issues raised by GasNet and other interested parties appropriately. Through the provision of a reward for efficiency gains and the exclusion of pass through events from the mechanism, the benefit sharing scheme should be consistent with GasNet's legitimate interests and investment in the covered pipeline (consistent with sections 2.24(a) and 8.48 of the Code). Given that one of the main objectives of the mechanism is to encourage least cost operation of the pipeline, the rolling carryover should promote economic efficiency (section 2.24(d)) and the public interest in having competitive markets (section 2.24(e)).

The Commission has assessed the views of interested parties and considers that the design of the mechanism for subsequent periods is appropriate as it should provide

GasNet with an incentive to minimise the overall costs attributable to providing the service consistent with the safe and reliable provision of the services (section 8.46(b) of the Code) and should ensure that users and prospective users gain from increased efficiency and may share in future efficiency benefits achieved regardless of whether they are temporary or permanent (consistent with sections 2.24(f), 8.46(e) and 8.48 of the Code).

The Commission notes that since releasing its Draft Decision, the ESC has issued its final decision in relation to the Victorian gas distributors. In its decision the ESC considered that an automatic carryover of any accrued negative amount was not appropriate as it may dampen incentives, but that it should have discretion on this issue.[646]

The Commission has given careful consideration to the reasons underlying the ESC's decision. Notwithstanding this, the Commission maintains its view set out in the Draft Decision that an automatic negative carryover will not harm incentives and will provide some certainty regarding the application of the benefit sharing approach. A negative carryover simply represents a penalty for being less efficient, just as a positive carryover amount is a reward for being more efficient. While a positive or negative carryover will increase (decrease) the service provider's revenues in the subsequent access arrangement period, it will not influence the sharing of future efficiencies and thus the incentive for gains within that period. In addition, a mechanism that is not characterised by an automatic negative carryover may generate an incentive for the service provider to game the regulator, potentially creating inefficient outcomes (see section 10.1.5 of this Final Decision). Consequently, the allowance for an automatic carryover of is in the interests of users and the public interest (sections 2.24(e) and (f)) and should promote the achievement of economic efficiency (section 2.24(d)). While it is possible that an automatic carryover may harm the interests of the service provider in the short term, the Commission does not consider that these costs outweigh the benefits to users and efficiency noted above (section 2.24(a)).

In conclusion, the Commission is of the view that the benefit sharing approach as proposed in the Draft Decision for operations and maintenance costs in the second period is appropriate, except that pass through events should be excluded from the mechanism. An amendment to the proposed revised access arrangement is required.

[646] ESC, *Final Decision: review of gas access arrangements*, October 2002, p. 167.

Amendment 40

GasNet must amend clause 7.2 of its revised access arrangement so that the benefit sharing allowance for operations and maintenance costs calculated for the third access arrangement period is based on the rolling carryover mechanism. The amendment must:

- allow GasNet to keep unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years;
- allow for the carryover of both unanticipated gains and losses;
- determine operations and maintenance expenditure achieved by GasNet in 2007 by taking 2006 actuals and adjusting these by the change in expenditure which is forecast to occur between 2006 and 2007;
- not allow for volume growth, except for operations and maintenance costs associated with capital expenditure deemed prudent and rolled into the asset base;
- adjust second period forecast costs for any positive or negative pass through events that may occur within the period;
- adjust second period forecast costs for regulatory review expenses; and
- ensure that all amounts are expressed in 2008 dollars.

Benefit sharing for the first period

The Commission also intends to maintain the approach proposed in the Draft Decision with regard to the benefit sharing calculation for the first access arrangement period. For capital expenditure, the Commission concurs with GasNet that a P_0 mechanism is appropriate.

For operations and maintenance expenditure, the Commission considers that the rolling carryover mechanism should not be applied to first period efficiencies achieved. This is because GasNet was not aware of the rolling carryover incentive model and could not respond to it in the first period. As indicated in the Draft Decision, the Commission regards the adoption of a glide path sharing mechanism for any gains achieved between 1998-2002 as appropriate. The Commission notes that in its final decision the ESC adopted a rolling carryover mechanism to be used to calculate the carryover amount for the first period efficiency gains into the second access arrangement period. The Commission believes, however that a glide path mechanism is more appropriate in light of the Code provisions and the relevant fixed principles.

As set out in the Draft Decision, a glide path mechanism is likely to be more appropriate for first period gains given that this model was flagged at the start of the first access arrangement period and also in the Commission's DRP.[647] It is likely that GasNet would have broadly responded to the incentives provided by the glide path in the first period. Further, the adoption of an alternative mechanism at this stage may represent a violation of the 'regulatory compact' between the Commission and GasNet and may thus harm its legitimate business interests (section 2.24(a) of the Code).

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[647] ACCC, DRP, May 1999, p. 90.

In addition, the Commission believes a glide path mechanism is also appropriate in light of the fixed principles contained in its access arrangements approved in 1998. This requires the Commission, when making a price determination in relation to a tariffed transmission service for the 2003-2007 access arrangement period to ensure a 'fair sharing' between GasNet and its customers of the benefits achieved through efficiency gains and in ensuring a fair sharing of the benefit, to have regard to:

- the need to offer GasNet a continuous incentive to improve efficiencies both in operational matters and capital investment; and
- the desirability of rewarding GasNet for efficiency gains, especially where those gains arise from management initiatives to increase efficiency.

The Commission considers that in general a glide path mechanism is consistent with the requirements set out in the clause 9.2(a)(4) of the Tariff Order as it allows for a fair sharing of benefits between users and the service provider as well as provides some incentive for efficiencies throughout the period. In addition, it provided a framework to reward GasNet for efficiency gains resulting from management decisions made in expectation of the Commission applying a glide path mechanism. GasNet, in response to the Draft Decision, accepted the application of a glide path for first period efficiencies.[648]

The Commission assessed several potential methodologies for measuring efficiency gains (losses) under a glide path regime. The first approach considered was that adopted by the ESC for the Victorian electricity distributors. Under this approach efficiency gains are measured by taking the difference between actual and forecast operations in the fourth year of the regulatory period. The Commission, however, considered in the Draft Decision that this approach was not appropriate, as year four expenditures may not adequately reflect expenditure undertaken in the fifth year of the period.

The second approach for measuring efficiencies discussed in the Draft Decision involved taking the difference between forecasts established for the final year of the first regulatory period with forecasts for the subsequent period. Using this approach, it was calculated that GasNet achieved an efficiency loss over the first period of approximately $300 000 (in 2003 dollars). This calculation would require GasNet to be subject to a negative glide path adjustment in the forthcoming access arrangement period.

In its response to the Draft Decision, GasNet argued that the Commission has not made all of the necessary adjustments to the efficiency calculation approach. Specifically, it asserted that the second efficiency measurement should be adjusted for the increase in insurance premiums given that this increase in costs was outside of the control of GasNet. Using this methodology, GasNet argues that this generates a positive efficiency carryover, and consequently a positive glide path through the second access arrangement period.

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648 GasNet submission, 20 September 2002, p. 40.

After further consideration, the Commission concurs with GasNet that the increase in insurance costs should be excluded from the calculation. As suggested above in this section with regard to the rolling carryover mechanism, it would be logically inconsistent to incorporate pass through costs in the calculation of efficiencies, and consequently a retrospective adjustment for pass through amounts should be made to benchmark costs. For the reasons noted earlier when discussing benefit sharing in subsequent periods, forecast costs should also be adjusted so that regulatory review expenses are not included in the efficiency measurement.

The Commission has recalculated GasNet's first period efficiencies using this revised methodology and the revised operations and maintenance cost forecasts as noted in chapter 6.[649] This generates a 2002 cost forecast of $20.5 million and an average of second period forecasts (excluding review costs) of $19.3 million (2003 dollars). Therefore, this forecast comparison approach implies a measured efficiency of $1.2 million in 2003, and consequently a positive glide path for GasNet through the second access arrangement period.

The third approach to measuring efficiencies discussed in the Draft Decision involved an assessment of actual operations cost savings achieved by GasNet in the second access arrangement period. As noted in chapter 6 of this Final Decision, GasNet achieved substantial operating cost savings in the first access arrangement period. The table below shows actual operations and maintenance expenditure achieved by GasNet in the first period as well as forecasts made at the start of the access arrangement period (in 2003 dollars). These forecasts have been adjusted for regulatory review costs allowed in revenues but not levied, as well as for the increase in insurance in the final year of the access arrangement period.[650]

Table 10.3: Forecast and actual operations and maintenance costs, 1998 to 2002

	$ million[c]				
	1998	**1999**	**2000**	**2001**	**2002**
Forecasts[a]	20.4	20.1	19.9	19.5	21.0
Actuals	19.2	15.8	12.8	14.6	19.0[b]
Difference	1.2	4.3	7.1	4.9	2.0

Source: GasNet response to Commission, May 2002; ACCC analysis.

Notes: (a) Adjusted for the increase in insurance costs in 2002 and regulatory costs allowed but not levied. It does not include operations costs associated with the Interconnect, Southwest pipeline and Springhurst and Iona compressors. Inclusion of these costs would widen the temporary gain measured in the first period.

(b) Estimate of 2002 costs.

(c) All in 2003 dollars.

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649 It was decided for consistency with the second period mechanism that it was appropriate to adjust the 2002 operations costs benchmark as if there was an insurance pass through in that year.

650 Benchmark costs have not been adjusted for the increase in operations and maintenance costs associated with the introduction Iona and Springhurst compressors and the Southwest pipeline and Interconnect pipeline.

As Table 10.3 indicates, actual operations and maintenance expenditure achieved by GasNet was substantially less that forecast in the first access arrangement period. However, it is forecast that by the end of the period the cost savings achieved in the first half of the period will have been lost, indicating the temporary nature of this reduction in costs.[651] GasNet has benefited substantially from these temporary efficiencies and it therefore could be argued that there is a strong case that these gains should be shared with users in the second period through a negative glide path.

Thus, the second approach to measuring efficiencies implies the adoption of a positive glide path, whereas the third approach assessed by the Commission supports the implementation of a negative glide path.

As noted earlier, a number of submissions raised concern with the unsustainable nature of GasNet's first period operating costs. BHP Billiton claims that GasNet achieved some $20 million in operating cost savings, but is not required to share these with users because they are unsustainable. Similarly, the EUCV states that GasNet has been able to sensibly reduce operations costs in the first period, and that this saving should be shared with users. Amcor and PaperlinX asserted that the Commission must apply an appropriate efficiency saving factor to operations costs achieved.

The Commission concurs with submissions that GasNet achieved significant savings in the first period that should be shared with users (section 2.24(f) of the Code). That is, the Commission considers that on balance, the third approach to measuring gains in the first period represents the most appropriate mechanism. However, as discussed in the Draft Decision, because of the uncertainty relating to the benefit sharing mechanism applying to GasNet at the start of the initial access arrangement period and the lack of discussion relating to the treatment of losses, it would be unreasonable to deduct revenues from GasNet for temporary gains achieved (this action might violate section 2.24(a) of the Code). Therefore, on balance, the Commission considers that an efficiency carryover of zero in the second access arrangement period to be most appropriate for GasNet in this instance.

The Commission notes that if temporary gains are achieved in the second access arrangement period, then the rolling carryover mechanism will automatically adjust revenues so that the gains are shared with users.

Amendment 41

GasNet must amend section 3.5 of its revised access arrangement information to remove any benefit sharing allowance associated with the first access arrangement period.

The Commission considers that a number of interested parties have misunderstood the operation of the benefit sharing mechanism proposed for first period gains. The EUCV, for example, argued that the benefit sharing proposal is not appropriate as it is the responsibility of GasNet to declare that sustainable savings have been made. However, as discussed above, this is not the case. The Commission calculated the

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651 See chapter 6 of this Final Decision for details of the unsustainable nature of these costs.

savings in the first period using actual and forecast data. This process did not require GasNet to make a declaration regarding first period costs.

10.2 KPIs

10.2.1 Code requirements

Category 6 of Attachment A to the Code requires a service provider's access arrangement information to include information regarding key performance indicators (KPIs). Items specified as examples are industry KPIs used by the service provider to justify reasonably incurred costs and a service provider's KPIs for each pricing zone, service or category of asset.

10.2.2 Current access arrangement provisions

GasNet's access arrangement information currently includes four tables containing KPIs:

- O&M costs for TPA (now GasNet), AlintaGas, the Pipeline Authority (now EAPL) and the Pipeline Authority of South Australia (now Epic SA) in terms of cost, cost per 1 000 km and cents per GJ;
- TPA's forecast O&M costs from 1998 to 2002 in terms of cost, cost per 1 000 km and cents per GJ;
- TPA's zonal forecast from 1998 to 2002 in terms of O&M costs, quantity of throughput and cents per GJ; and
- cents per GJ for TPA (from Longford to Pakenham), EAPL (Moomba to Wilton), Epic (Moomba to Adelaide and Ballera to Wallumbilla) and Alinta (Dampier to Perth).

10.2.3 GasNet proposal

GasNet has provided KPIs based on data relating to seven Australian pipeline companies, using information available from access arrangement approval processes.[652] GasNet states that the data represent the forecast operating costs in 2003, net of working capital and compressor fuel costs. Operating costs comprise General and Administrative (G&A) and O&M costs. GasNet states that maintenance capital expenditure has not been included in the comparison.

GasNet states that normalising factors are needed to make costs comparable and that these consist of various measures of workload in order to attempt to represent the cost drivers of a particular company. GasNet states that its forecast costs for 2003 have been adjusted to make the KPIs more comparable by adding an allowance for gas control to GasNet's costs (a function that other companies perform but which is performed by VENCorp for the PTS) and by excluding the increment in insurance cost

[652] GasNet access arrangement information, 27 March 2002, pp. 31-36.

experienced by GasNet. The Cap Gemini benchmarking study provided by GasNet adopted an annual cost of $620 000 to accommodate the gas control function.[653]

Table 10.4 below provides a range of operations and maintenance expenditure comparisons.

Table 10.4: Australian pipeline KPIs

	Operating costs/ GJ $/GJ	Operating costs/ ORC %	O&M/ metre $/metre	G&A/ GJ $/GJ	O&M/ ORC $
PTS	0.08	2.1	5.09	0.03	1.2
Moomba-Adelaide	0.12	2.4	3.52	na	na
Moomba-Sydney	0.14	1.2	4.38	0.04	0.9
Dampier-Bunbury	0.15	1.8	13.46	0.02	1.5
Parmelia	0.21	2.4	8.45	0.02	2.1
Goldfields	0.42	2.4	5.37	0.13	1.6
Amadeus Basin	0.45	2.1	3.52	0.09	1.7
Central West	0.69	2.6	1.95	0.26	1.6

Source: GasNet access arrangement information, 27 March 2002, pp. 33-35.

In addition, GasNet provided a detailed benchmarking report compiled by Cap Gemini as an annexure to its submission, which it summarised in its access arrangement information. The report is based on GasNet's actual operating results for the year 2000 and also includes historical 1999 and projected year 2001 results. It compares GasNet's performance against a sample of 24 companies from Australia, Canada, USA and South America and against four specific peer group companies. GasNet selected three indicators as being the most representative of the cost efficiency of GasNet: G&A expenses per million cubic meters delivered; pipeline maintenance expenses; and compressor maintenance expenses. GasNet advises that these costs were defined specifically to enable inter-company comparisons and are not consistent with the definitions used for the comparison of Australian pipeline companies referred to earlier.

GasNet summarised findings of the report as follows:

- GasNet's overall G&A expenses per million cubic metres delivered were 55 per cent lower than the peer group average and GasNet's unit costs fell very close to the lowest or best quartile of all participating companies;
- GasNet's pipeline maintenance expenses per kilometre of pipeline system were lower than the peer group average and the all company median; and
- GasNet's compression costs were marginally higher than the median cost for the industry sample.

[653] GasNet submission, 27 March 2002, annexure 9, p. 25. This amount was incorrectly reported in the Draft Decision as $660 000.

The Cap Gemini report commented that GasNet has a very low compressor utilisation factor, reflecting its seasonal demand patterns, and that intermittent stop-start operation leads to higher costs compared to other companies. In contrast, some of the other companies in the sample operate long haul systems with very high unit horsepower and high utilisation rates.

Cap Gemini outlined the purpose and limitations of its study as follows:

> This benchmarking is focused on operational efficiency and effectiveness. It is not a tool that can be used for the following:
>
> 1. Setting transportation prices.
> 2. Determining precise levels of efficiency and precise targets for performance.
>
> Benchmarking is an approach to identifying the differences in your operations relative to a sample of other gas transmission companies. It is directional in nature; that is, pointing your company in the directions where it may wish to review operations for potential improvements in overall performance.[654]

10.2.4 Submissions to Issues Paper

A number of parties suggested that GasNet's and VENCorp's costs should be aggregated in order to make comparisons meaningful and that the data provided in relation to operating and marketing costs are inadequate.[655] BHP Billiton stated that, once aggregated, operations and maintenance related charges paid by users of the PTS would 'sit at the very high end of the range of local performance'. BHP Billiton further commented that those costs referred to by GasNet as exceptional costs should be included in the comparisons. BHP Billiton estimated that if these adjustments are made that the KPIs for the PTS would be approximately double those shown in Table 10.4 above.[656] BHP Billiton expressed concern that inappropriate use of benchmarking could lead to GasNet being over compensated for efficiency gains and suggests that it be set challenging targets for the second access arrangement period.

In addition, BHP Billiton considered that GasNet's approach has been to provide KPIs based solely on Australian pipeline systems, and that this is inadequate as there are only a relatively few independent gas transmission system service providers in Australia and such comparisons 'will result ultimately in circular prophesies'.[657] BHP Billiton submitted that GasNet should be required to identify comparable overseas benchmarks.

EnergyAdvice benchmarked GasNet's current and proposed tariffs (for Tariff D customers) against those for DEI's EGP (from Longford to Horsley Park) and the current tariffs for the EAPL pipeline (from Moomba to Wilton). Table 10.5 below provides EnergyAdvice's estimates of the tariff for each of the pipelines after adjustment for load factor and distance expressed as dollars per terajoule per kilometre of pipeline.

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654 GasNet submission, 27 March 2002, annexure 9, p. 7.

655 See for example BHP Billiton submission, 21 June 2002, pp. 40-41

656 One exception is that BHP Billiton's estimate for G&A per GJ of $0.04 is a third higher than GasNet's figure of $0.03.

657 BHP Billiton submission, 17 May 2002, pp. 13-14.

EnergyAdvice concluded that the proposed GasNet charges are the highest of the three transmission pipelines when compared on a dollar per TJ per kilometre basis, other than for the Echuca zone for a relatively average load factor.[658] EnergyAdvice commented that the comparison highlights that the proposed GasNet tariff structure is relatively insensitive to load factor.

Table 10.5: Australian transmission pipeline tariff comparison[a]

Customer	Load factor	GasNet $/TJ/km current	GasNet $/TJ/km proposed	EAPL $/TJ/km current	EGP $/TJ/km published	EGP $/TJ/km July 2003
Metro	90%	$1.11	$1.83	$0.56	$1.19	$0.87
% of current GasNet		100%	166%	51%	108%	78%
Metro	75%	$1.20	$1.90	$0.67	$1.43	$1.04
% of current GasNet		100%	159%	55%	119%	87%
Metro	60%	$1.34	$2.01	$0.82	$1.79	$1.30
% of current GasNet		100%	150%	62%	134%	97%
Echuca	75%	$1.55	$1.49	$0.67	$1.43	$1.04
% of current GasNet		100%	96%	43%	92%	67%
Echuca	60%	$1.78	$1.53	$0.82	$1.79	$1.30
% of current GasNet		100%	86%	46%	101%	73%
Wodonga	75%	$1.39	$2.23	$0.67	$1.43	$1.04
% of current GasNet		100%	160%	48%	103%	75%
Wodonga	60%	$1.61	$2.26	$0.82	$1.79	$1.30
% of current GasNet		100%	140%	51%	111%	81%

Source: EnergyAdvice submission, 30 May 2002, p. 12.
Note: (a) Calculations are based on a customer with an annual volume of 1 PJ with the load factor adjusted by varying the MDQ.

TXU stated that it is not convinced of the validity of the reasons given by GasNet for excluding and adjusting costs and considers that the KPIs provided may be misleading.[659] For example, TXU stated that 'GasNet does monitor very carefully VENCorp's operation of its compressors' and that 'GasNet should be able to derive benchmarks with compressor fuel in order to provide a basis for determining whether its forecast compressor costs are reasonable'. In addition, TXU stated that it does not agree with the exclusion of maintenance capital expenditure, and questions whether this expenditure has been excluded from the comparators. Further, TXU enquired as to the basis and size of adjustment made in respect of VENCorp's functions.

[658] EnergyAdvice submission, 30 May 2002, p. 12.

[659] TXU submission, 31 May 2002, p. 37.

10.2.5 Draft Decision

The Commission noted in its Draft Decision that it is cognisant of the limitations of benchmarking studies. It acknowledged these must be taken into account when considering the results of the studies. These limitations include:

- differing characteristics of pipelines (for example, maturity and average load, length and diameter);
- uncertainties of adjustments (for example, for VENCorp functions); and
- usefulness of specific KPIs.

In particular, the Commission noted in the Draft Decision that GasNet had not provided data on a key indicator, O&M/TJ/km. The Commission commented that it considered that this KPI could materially help interested parties to make an informed assessment of GasNet's performance and assist them to form an opinion as to the compliance of the revised access arrangement with the provisions of the Code. Accordingly, an amendment to GasNet's access arrangement information was proposed.

The Commission acknowledged the difficulty noted in submissions of comparing GasNet's performance under a market carriage system with that of other Australian pipelines that operate on a contract carriage basis. GasNet has included an amount to its own costs in its comparisons in recognition of the gas control functions performed by VENCorp. However, this represents only a small part of the costs of approximately $16 million a year that users pay for VENCorp services, which include a range of other functions such as operating the Victorian gas market.

BHP Billiton estimated that GasNet's costs expressed in its KPIs, if adjusted for VENCorp costs, would be approximately double that indicated by GasNet. On this basis, GasNet's costs would be higher than that of its comparators. The Commission noted that these comparisons raise issues in terms of the costs of both service providers, the relative costs of the market carriage and contract carriage capacity systems and the comparability of the pipeline systems themselves. The Commission acknowledged that the PTS is unusual for a transmission system as it has significant network characteristics not shared with other Australian transmission systems. Further, the PTS has a very peaky load but little linepack. Accordingly, it would be expected to face significantly greater gas control costs than other Australian transmission pipelines.

The Commission noted in its Draft Decision that the Cap Gemini study provided by GasNet was commissioned to identify areas in which GasNet 'may wish to review operations for potential improvements in overall performance' rather than as an adjunct to a tariff review.[660] For this reason, and others (such as that comparator companies have not been identified), the Commission was of the view that it is of limited relevance to the current review process. Nonetheless, the Commission considered that overseas benchmarks are potentially very useful. It noted the dangers expressed by one interested party of Australian regulators becoming caught in a circular comparison of regulated costs.

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[660] GasNet submission, 27 March 2002, annexure 9, p. 7.

As a result of the unique factors inherent to the Victorian gas transmission system, the Commission commented that it considers that the available KPIs are inconclusive. It was unable to isolate the influences of the characteristics of the PTS, the market carriage system and that of GasNet itself. The Commission stated that it expects that the 2007 review by the Victorian Government of the market arrangements will carefully examine the interaction of these factors.

The Commission commented that it prefers not to attempt to 'micro manage' GasNet with regard to its costs. It stated that it considers that effective efficiency incentives are more likely to lead to efficient performance. Accordingly, the Commission commented that it places considerable priority on the future incentives mechanisms applying to GasNet.

The Commission further commented that clear signals were not available to GasNet and its predecessors during the first access arrangement period. For this reason, the Commission carefully considered GasNet's proposed benchmark costs for the second access arrangement period and proposed a number of changes to those forecast by GasNet.

10.2.6 Response to Draft Decision

As proposed in the Draft Decision, GasNet provided an additional KPI (O&M/km/PJ) as shown in Table 10.6 below.

Table 10.6: Additional Australian pipeline KPI

	O&M/ km/ PJ $/km/PJ
PTS	40
Moomba-Adelaide	111
Moomba-Sydney	67
Dampier-Bunbury	80
Parmelia	469
Goldfields	303
Amadeus Basin	268
Central West	2 700

Source: GasNet submission, 20 September 2002, Annexure E.

Submissions from BHP Billiton, EUCV and Amcor and PaperlinX commented on the adequacy of KPIs and the Commission's assessment in its Draft Decision.[661]

BHP Billiton's comments included:

[661] BHP Billiton submissions 13 September 2002, pp. 15-16 and 11 October 2002, pp. 9-12; EUCV submission, 9 October 2002, pp. 6-7; Amcor and PaperlinX submission, 10 October 2002, p. 2.

- that the Commission had (rightfully) noted that the GasNet system has many features of a distribution system. BHP Billiton states that, using the benchmark 'non-capital costs per kilometer of mains', GasNet performs poorly compared with the Victorian gas distribution businesses;
- that the Commission incorrectly included the gas control function in its consideration of GasNet's cost;
- that the Code requires performance comparisons to be made against 'similar regulated international businesses' and that 'the ACCC has not carried out any significant local or international performance benchmarking, despite this being a clear requirement of the Gas Code'; and
- that the Commission has accepted that 'the only benefit GasNet sees VENCorp provides over equivalent pipeline operators using the contract carriage model is valued at $660 000 per annum over GasNet costs'.[662]

The other interested parties identified made similar observations to those of BHP Billiton.

10.2.7 Final Decision

The Commission has carefully considered the issues raised in submissions. A number of the specific comments are addressed below.

BHP Billiton states that the Commission had commented that the PTS has many features of a distribution system, and that it would be appropriate to benchmark the costs of the PTS against the Victorian gas distribution businesses. However, the Commission had commented that the PTS has many features of a network (rather than a distribution) system. With multiple injection points and limited linepack, the PTS would reasonably be expected to incur higher gas control costs than other Australian transmission pipelines. The Commission considers that the benchmark comparison suggested by BHP Billiton would be misleading because distribution systems generally consist of small diameter pipes operating under low pressures. Accordingly, their non-capital costs per kilometre of mains would be expected to be far lower than that of transmission pipelines with comparatively large diameter pipes operating under high pressures.

BHP Billiton suggests that the Commission incorrectly included the gas control function in its consideration of GasNet's cost. However, the Commission's observations in its Draft Decision regarding the gas control function related to the PTS. This was not an observation on GasNet's costs specifically but on expected costs on the system (in this case in relation to a function performed by VENCorp).

Consistent with the requirements of Attachment A (Category 6) of the Code, the Draft Decision reported a number of international and local performance benchmarking results based on information provided by GasNet (and its consultant, Cap Gemini).[663] BHP Billiton appears to have concluded that the Commission comment that 'the Cap

[662] BHP Billiton submission, 11 October 2002, pp. 10-11.

[663] The Commission reported these results but did not reiterate them when discussing its considerations.

Gemini report has limited if any application to the current review'[664] indicated that it had not taken Cap Gemini's report into consideration. However, BHP Billiton has overstated the Commission's reservations. It did take the international benchmarking results reported by Cap Gemini into account. These generally suggest that GasNet's costs are not unreasonable.

The Commission notes that BHP Billiton appears to suggest that the Code places a specific obligation on the regulator to undertake its own benchmarking studies. While the Commission may undertake such studies from time to time, there is no specific obligation. It is not normal practice for the Commission or other Australian regulators to undertake their own benchmarking studies for specific approval processes. The Commission notes that BHP Billiton's reference to a Code requirement to consider international performance benchmarking appears to be to section 8.10(e) of the Code which the regulator must consider when establishing the initial capital base for an existing pipeline. This is not directly relevant to the assessment of revisions to an access arrangement or to non-capital costs.

As noted in the Draft Decision, one factor that needs to be considered when benchmarking GasNet's operations against other pipelines is that VENCorp performs the gas control function for the PTS whereas this is usually performed by the pipeline owner. GasNet has estimated that it would cost it $620 000 a year to perform this function. In order to facilitate comparisons, it added this amount to its costs. BHP Billiton in particular questioned whether this amount was adequate.

The Commission understands that GasNet operated gas control facilities when the current market structure was initiated. While VENCorp acquired its own facilities, GasNet's existing facilities remain. They are currently used in connection with the Dandenong LNG reservoir but essentially retain the capacity to allow the gas control function to be performed with respect of the PTS. GasNet's estimate of $620 000 per year covers the incremental cost of operating these existing facilities, an amount assessed by the Commission's technical consultant as being not unreasonable. Accordingly, the Commission considers it appropriate to include this amount in the benchmark comparisons.

GasNet has advised that the amount of $620 000 per year was determined and agreed in discussions with Cap Gemini at the commencement of the study.[665] GasNet noted the variety of functions performed by VENCorp in addition to the gas control function, in particular its role in operating the market. For example, whereas users are obliged on other systems to maintain a balance between their own injections and withdrawals (or incur an imbalance penalty), this is not required on the PTS with imbalances being settled at a spot market price. Similarly, whereas users are obliged to provide their own demand nominations under contract carriage, VENCorp performs this function for the majority of the market.

As discussed in the Draft Decision, a number of the features of the PTS and its operating environment make comparisons with the operations of other pipelines

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664 BHP Billiton submission, 11 October 2002, p. 10.

665 GasNet response to the Commission, 7 May 2002, p. 1.

difficult. Simply aggregating VENCorp's full costs with GasNet's O&M costs as advocated by some parties would provide a misleading indication of relative performance. The Commission disagrees with BHP Billiton's suggestion that the $620 000 accurately quantifies the full benefits provided by VENCorp. VENCorp has a range of roles beyond the gas control function.

The Commission has carefully assessed GasNet's performance against available KPIs. While acknowledging the difficulties of comparing different systems, the Commission has concluded that GasNet generally compares well with other Australian pipeline companies. In addition, GasNet's costs are generally not unreasonable when compared with the overseas pipelines in the Cap Gemini study. The Commission notes that, even if moderately larger costs are allowed for gas control functions, GasNet's proposed benchmark costs do not appear to be unreasonable.

The Commission reiterates that it prefers not to attempt to 'micro manage' GasNet with regard to its costs. It considers that effective efficiency incentives are more likely to lead to efficient performance. Accordingly, the Commission places considerable priority on the future incentives mechanisms applying to GasNet (see section 10.1 of this Final Decision).

The Commission notes the tariff comparison provided by EnergyAdvice which indicates that GasNet's proposed tariffs are generally higher than those charged on the MSP and the EGP. The Commission has found that GasNet's proposed tariffs are unnecessarily high. This Final Decision sets out a number of amendments to GasNet's revised access arrangement which will result in the implementation of significantly lower tariffs from 1 January 2003 (compared with those proposed by GasNet).

As noted in the Draft Decision, an amendment is required to GasNet's access arrangement information to include O&M costs per unit per distance data in its comparison of Australian KPIs. GasNet has agreed to this amendment and has provided the necessary information. The Commission notes that GasNet performs very well when considered using this measure.

Amendment 42

GasNet must amend section 6 of its access arrangement information to include operations and maintenance costs/km/PJ data in its comparison of Australian KPIs.

11. Non tariff elements

11.1 Services policy

Section 2.3.4 of this Final Decision discussed the interaction of GasNet's and VENCorp's access arrangements with regard to the PTS. This section considers in more detail GasNet's proposals with respect to reference services.

11.1.1 Code requirements

Sections 3.1 and 3.2 of the Code require an access arrangement to include a services policy which 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 services policy.

To the extent that it 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 this is requested.

11.1.2 Current access arrangement provisions

Clause 5.2.2 of the PTS access arrangement currently states that GasNet's predecessor, TPA will make the tariffed transmission service available to VENCorp as user at the reference tariffs, on the terms and conditions and in accordance with the reference tariff policy described in the access arrangement. Similarly, the WTS access arrangement states that TPA will make tariffed transmission services (the reference services) available to users or prospective users at the reference tariffs, on the terms and conditions, and in accordance with the reference tariff policy described in the access arrangement. Both access arrangements state that the services are likely to be sought by a significant part of the market.

11.1.3 GasNet proposal

GasNet notes in clause 3.1 of its proposed revised access arrangement that it owns the PTS but that VENCorp operates the PTS, VENCorp obtains the availability of the PTS from GasNet and that market participants contract directly with VENCorp in accordance with the MSOR for access to the PTS. GasNet states that it and VENCorp are parties to the SEA, under which GasNet makes the PTS available to VENCorp and provides a range of supporting services to VENCorp; and that VENCorp operates the PTS in accordance with the MSOR and agrees to direct market participants to pay the transmission tariffs directly to GasNet.

GasNet states that under the market carriage capacity management system, users and prospective users of the PTS are offered one reference service (or bundle of services) comprising the transportation of gas through the PTS via the market carriage system under the MSOR. GasNet states that VENCorp, as operator of the PTS under the

MSOR, is responsible for the provision of the reference service. GasNet also claims that although it is a service provider under the Code (because service provider is defined to include both the operator and the owner of a pipeline), GasNet does not, under the MSOR regime, provide any aspect of the reference service directly to users. GasNet considers that the current provisions are inappropriate as it considers that 'VENCorp is not a "User" within the meaning of the Code' and it proposes to alter its access arrangement accordingly.[666] GasNet states that the change would have no substantive impact on users shipping gas via the PTS.

GasNet states that, for the purposes of reference tariff calculation, the reference service comprises VENCorp Services (within the VENCorp access arrangement) and the tariffed transmission service (being the availability of the PTS, which is sourced by VENCorp from GasNet through the SEA). GasNet states that it 'proposes to revise the form of its Services Policy to bring it into line with underlying commercial and regulatory arrangements'.[667]

11.1.4 Submissions to Issues Paper

ENERGEX stated that it finds 'it difficult to reconcile GasNet's application for tariff approval by the ACCC under the National Access Code without a description of [an] actual reference service' and asks the Commission to request GasNet to properly follow the requirements of the Code.[668]

VENCorp disagreed with GasNet's contention that GasNet does not provide services to users on the grounds that VENCorp is a user of GasNet services, which VENCorp notes is currently acknowledged in the PTS access arrangement.[669] VENCorp considered that this description should continue 'given that section 10.8 of the Access Code defines a user to include "a person who has a current contract for a Service"'. VENCorp (provided as an attachment to its submission) a legal advice consistent with its position that GasNet's proposal would not comply with the Code as the revised access arrangement would not clearly state the reference service to which the reference tariff would relate or the terms and conditions of supply.[670] Further, VENCorp stated:

> In a regulatory sense, it would be an unacceptable outcome if:
>
> - GasNet, which accounts for around 85% (about $A95 million per annum) of the total annual transmission costs for the main Victorian transmission system, had no reference services for these charges defined in the access arrangement which sets out the associate GasNet reference tariffs;
> - GasNet were able, as a result of its services not being specified in its access arrangement, to alter its services such that they were in conflict with the statutory functions of VENCorp as operator of the PTS; or
> - Prospective users on the PTS were precluded from recourse to GasNet via the access dispute processes in the Access Code in regard to services provided by GasNet. This could

[666] GasNet submission, 27 March 2002, p. 122.

[667] ibid., p. 122.

[668] ENERGEX submission, 9 May 2002, p. 1.

[669] VENCorp submission, 13 May 2002, p. 5.

[670] ibid., p. 5.

> arise if GasNet does not define its reference services and the terms and conditions of access in its access arrangement. [671]

VENCorp submitted that its preference is for the existing allocation to at least continue, such that:

> … each of VENCorp and GasNet should describe the reference services it provides, and the terms and conditions on which it offers those services, in its access arrangement. Preferably GasNet should include in its access arrangement either the entire Service Envelope Agreement, or describe the key obligations from that agreement. Together, the two access arrangements should describe the total services provided to users, and each entity should describe the particular reference services for which it seeks approval of a reference tariff.[672]

The Victorian Department of Natural Resources and Environment (DNRE) also provided as an attachment to its submission a legal advice consistent with its position that the Commission should not approve GasNet's proposal as GasNet provides services to VENCorp within the meaning of the Code.[673]

TXU is also of the view that GasNet should provide a reference service and is obliged to by the provisions of the Code. It stated that it is important for users such as TXU to understand the exact services provided by each of the system owner and operator. TXU is concerned that, while the relationship and division of responsibilities between GasNet and VENCorp is currently made clear by their access arrangements, this would not be the case under GasNet's proposal.[674] TXU commented that it must deal regularly with GasNet, for example when paying for services or when seeking a new connection or additional capacity on the system.

TXU considered that VENCorp is a user of GasNet's services, and that VENCorp's ability to deliver the VENCorp reference services is dependent on GasNet providing capacity of its pipelines available for use by VENCorp under various stipulated operating conditions. TXU also suggested that it should be able to enforce an access dispute directly against GasNet but that it could only pursue VENCorp under the proposed model.[675]

Pulse considered it inconsistent for GasNet to assert that it has no reference services while seeking reference tariffs. Pulse considered that GasNet's services are provided to users through the SEA with VENCorp. It stated that if GasNet's services are deemed not to be reference services VENCorp will be 'in the invidious position of having to pass through costs negotiated on a commercial basis'.[676] Pulse noted that this would also leave users without direct recourse to GasNet in the event of non-performance. Further, Pulse commented that the contention that only VENCorp uses GasNet's reference services would overlook those 'customers who come directly off the Principal

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[671] ibid., p. 4.

[672] ibid., p. 4.

[673] DNRE submission, 20 May 2002, p.1.

[674] TXU submission, 31 May 2002, p. 3.

[675] ibid., p. 4.

[676] Pulse submission, 16 May 2002, p. 3.

Transmission System'. Pulse contended 'services generated by the infrastructure owned by GasNet should be characterised by reference services and reference tariffs'.[677]

BHP Billiton questioned whether the legal rights of shippers would be affected by GasNet's proposed changes to its access arrangement 'bearing in mind that VENCorp has no liability to shippers for its actions'.[678] Amcor and PaperlinX similarly commented that users might lack effective redress and recommended that users be able to 'bypass VENCorp and seek restitution from GasNet who not only does not have legislative protection, but also has the assets from which restitution can be funded'.[679]

TXU considered that, depending on the outcome of the commercial negotiations between GasNet and VENCorp, it may be appropriate for the Commission to consider inclusion of LNG storage for system security purposes as a reference service.

11.1.5 Draft Decision

The Commission considered in its Draft Decision the views put by interested parties, including a number of legal advices.

The Commission expressed concern that VENCorp's access arrangement as proposed would not reflect the allocation of responsibility between GasNet and VENCorp as it would not acknowledge that VENCorp is the entity that supplies the whole service to retailers. Consequently, it proposed an amendment to require VENCorp to amend its proposed services policy to clarify that it is VENCorp who provides to users, not only VENCorp Reference Services, but also the transportation of gas through the PTS via the market carriage system under the MSOR.

Differing views were expressed as to whether GasNet is supplying a service to VENCorp and whether VENCorp is a user in the terms of the Code.

Section 10.8 of the Code provides the following relevant definitions:

> **'Service'** means a service provided by means of a Covered Pipeline (or when used in section 1 a service provided by means of a Pipeline) including (without limitation):
>
> (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul);
>
> (b) the right to interconnect with the Covered Pipeline; and
>
> (c) services ancillary to the provisions of such services,
>
> but does not include the production, sale or purchasing of Natural Gas.
>
> **'User'** means a person who has a current contract for a Service or an entitlement to a Service as a result of an arbitration.

The Commission concluded that GasNet is supplying a service (the tariffed transmission service) to VENCorp within the meaning of section 10.8 of the Code. GasNet describes this service as being the availability of the PTS, which it states is

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677 ibid., p. 3.

678 BHP Billiton submission, 17 May 2002, p. 9.

679 Amcor and PaperlinX submission, 24 June 2002, p. 25.

sourced by VENCorp from GasNet through the SEA.[680] The Commission concluded that VENCorp is a user of this service as it has a current contract (the SEA) with GasNet for this service. Further, as VENCorp is the only user of this service, and it has expressed its desire to be provided with a reference service by GasNet, the Commission concluded that this service is 'likely to be sought by a significant part of the market' (section 3.2(a)(i) of the Code).

The Commission also concluded that GasNet should include in its services policy the services that it supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, it noted that clause 3.2 of GasNet's proposed revised access arrangement refers to 'VENCorp Services' whereas this should be to 'VENCorp Reference Services'. Accordingly, an amendment was proposed.

11.1.6 Response to Draft Decision

VENCorp has agreed to the amendment proposed in the VENCorp Draft Decision to its proposed services policy to clarify that it is VENCorp who provides to users, not only VENCorp Reference Services, but also the transportation of gas through the PTS via the market carriage system under the MSOR.[681] However, VENCorp stated that this would be contingent on GasNet's services policy being amended in accordance with the amendment proposed in the GasNet Draft Decision and the 'actual drafting of the amendments to GasNet's Revised Access Arrangement'.[682]

GasNet reiterated its position 'that it does not provide a service to VENCorp within the meaning of the Code'.[683]

11.1.7 Final Decision

The Commission accepts the submissions by VENCorp and a number of other parties that the relationship between GasNet and VENCorp is fundamental to VENCorp's ability to supply services to third parties. In effect, the inclusion of the service supplied by GasNet to VENCorp in GasNet's services policy gives regulatory certainty to the availability of the PTS to enable VENCorp to operate it in accordance with the MSOR.[684] In addition, the Commission notes its discretion under section 3.2(a)(ii) of the Code to determine if any service(s) should in its opinion be included in the services policy. After considering these factors, the Commission has concluded that GasNet's proposed departure from the current services policy is not in the interests of VENCorp, users of the services provided by VENCorp or the public more generally (see sections 2.24(e) and (f) of the Code).

Accordingly, the following amendment is required.

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680 GasNet access arrangement, 27 March 2002, p. 4.

681 VENCorp submission, 13 September 2002, p. 5.

682 ibid.

683 GasNet submission, 20 September 2002, p. 41.

684 Although an access arrangement is not binding, under s 6.18 of the Code, an arbitration decision must be consistent with the access arrangement.

Amendment 43

GasNet must amend clause 3 of its revised access arrangement, services policy, to include the services that GasNet supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, the reference 'VENCorp Services' in clause 3.2 must be changed to 'VENCorp Reference Services'.

The Commission considers that the amendment is not inconsistent with GasNet's legitimate business interests and investment (section 2.24(a) of the Code). The Commission's amendment merely reflects GasNet's current obligations under the MSOR and SEA. GasNet disputes that these services come within the definition of service, but has not referred to any practical disadvantages for GasNet.

11.2 Terms and conditions

11.2.1 Code requirements

Section 3.6 of the Code requires an access arrangement to include the terms and conditions on which a service provider will supply each reference service. Based on the regulator's assessment, these terms and conditions must be reasonable.

11.2.2 Current access arrangement provisions

The current provisions of the PTS access arrangement state that the service provider will make the PTS available to VENCorp in accordance with the SEA. The SEA is a contract between the service provider and VENCorp which requires that the 'gas transmission system' (which is described in detail in the SEA) be made available to VENCorp at all times over the term of the agreement. Failure to do so attracts a penalty.

In addition, the SEA requires VENCorp to operate the gas transmission system in accordance with good practice. VENCorp is to provide services to users in accordance with the MSOR and the Gas Transportation Deed. Users are required to pay GasNet directly for transmission charges.

The access arrangement also states that the service provider is to supply reference services (that is, the tariffed transmission service) in accordance with schedules 1 and 5 of the Tariff Order (which set out the initial reference tariffs and the tariff control formula).

In contrast, the WTS access arrangement does not refer to any external documents in relation to the terms and conditions of providing the reference service. The current provisions of the WTS access arrangement state that the service provider will provide tariffed transmission services to users in accordance with schedules 1 and 4 of the access arrangement (which set out the initial reference tariffs and the tariff control formula). In addition, the terms and conditions of supply must be consistent with the pro-forma Western Transmission System Agreement (at appendix 2 of the access arrangement).

11.2.3 GasNet proposal

GasNet proposes to revise the access arrangements to state that 'terms and conditions on which the Reference Service is supplied are as set out in the MSO Rules from time to time'.[685] It also states that the obligations to comply with section 3.6 of the Code are allocated to VENCorp.

GasNet views the reference service as containing two components. One component is VENCorp services (provided by VENCorp to users according to the VENCorp access arrangement) and the other is the tariffed transmission service (that is, the benefit of the availability of the pipeline system).

The effect of the SEA is that VENCorp has the operational control of the entire pipeline system. GasNet and VENCorp propose to extend the SEA to the current WTS if the Commission agrees with their proposal that the PTS and WTS be covered by the one access arrangement. The parties have also agreed to extend the term of the SEA to 31 December 2007 to coincide with the proposed conclusion of the forthcoming access arrangement period.[686]

11.2.4 Submissions to Issues Paper

VENCorp stated that it has prepared revisions to its access arrangement on the basis that:

> … GasNet will continue to describe in its access arrangement the transmission services and capacity provided to VENCorp, as a current User of these services. To the extent that GasNet does not do so, the access arrangements may be inconsistent in their current form. VENCorp's strong preference remains for GasNet to include the Service Envelope Agreement, or at least key obligations from that agreement, in GasNet's access arrangement. This position was strongly supported by market participants as Users during VENCorp's recent public pre-consultation on its access arrangements.[687]

In a subsequent submission, VENCorp noted that GasNet has not provided any terms and conditions in its access arrangement and has only referred to the MSOR. VENCorp considered this to be too general as it 'does not describe in sufficient detail for users the actual services provided by GasNet, and ignores the terms and conditions of the Service Envelope Agreement'.[688]

Legal advice obtained by VENCorp suggested that not only must an access arrangement specify the reference services offered by the service provider (see section 11.1 above), it must include the terms and conditions on which those services are provided.[689] VENCorp suggests that compliance with the Code can be obtained by GasNet 'including in its access arrangement either the entire Service Envelope Agreement, or describing the key obligations from that agreement'.[690]

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685 GasNet access arrangement, 27 March 2002, p. 4.

686 GasNet submission, 27 March 2002, pp. 10-11.

687 VENCorp submission, 28 March 2002, p. 4.

688 VENCorp submission, 13 May 2002, p. 6.

689 ibid., advice provided by Corrs Chambers Westgarth, 30 April 2002, p. 7.

690 VENCorp submission, 13 May 2002, p. 3.

Similarly, BHP Billiton stated 'the aggregated "terms and conditions" applying to the aggregated services need to be presented. It is not the role of the ACCC nor of users to make their own decisions and estimates of the cost and conditions applying to the full service'.[691]

ENERGEX commented that the SEA is not publicly available and states that it:

> … understands it is ostensibly a bilateral contract describing the manner in which transmission pipeline assets will be made available for the operator to use. If this understanding is correct, there would appear to be no reason why the contents of the SEA should not form part of the public access application (of both VENCorp and GasNet).[692]

TXU regarded the proposed revised access arrangement as flawed as it does not provide a description of reference services; does not recognise the relationship between users and GasNet; and potentially avoids valid access dispute resolution processes.[693] It suggested that the revised access arrangement should include a clear description of services, the SEA or key obligations from the agreement. TXU also expressed concern regarding GasNet's reference to the MSOR:

> The MSO Rules do not of themselves impose clear obligations on GasNet to ensure that GasNet maintains the system and provides the transportation and capacity services required by TXU and other users. Similarly, GasNet has a wide discretion outside the role of VENCorp under the MSO Rules in relation to extensions and expansions. Therefore, it is not enough for GasNet to assert that the terms and conditions will be the MSO Rules as in force from time to time.[694]

BHP Billiton suggested that with three sets of terms and conditions applying to gas transmission (that is, those from GasNet, VENCorp and the MSOR) confusion and potential conflict is likely. Consequently, it suggested that 'a single set of all-encompassing rules, rights and obligations of the three parties to the Victorian gas access arrangements' is needed. In addition, BHP Billiton recommended an open forum to discuss the appropriateness of these rules.[695]

11.2.5 Draft Decision

Submissions provided by interested parties indicated some concern among market participants about the proposal from GasNet to exclude terms and conditions from its revised access arrangement. In particular, the inclusion of the SEA (either in full, or its key features) in the access arrangement has been suggested.

The Commission noted that the 1998 SEA is available from the Commission's website but that it understood that the parties intend to make some changes to the current agreement. At the time of the Draft Decision, the Commission had not been advised as to whether the amended SEA would be publicly available.

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[691] BHP Billiton submission, 17 May 2002, p. 9.

[692] ENERGEX submission, 9 May 2002, p. 1.

[693] In response, GasNet states that its proposed changes 'will have no material effect on the access of Users to an enforceable dispute resolution process' and notes that the SEA includes a dispute resolution process for disputes between GasNet and VENCorp. GasNet response to submissions, 12 June 2002, p. 4.

[694] TXU submission, 31 May 2002, p. 4.

[695] BHP Billiton submission, 21 June 2002, p. 38.

The Commission noted that, in general, it would expect an access arrangement to contain all the information regarding access to the services provided by the pipeline for users and prospective users. However, inclusion of the complete SEA in GasNet's access arrangement may be inappropriate as it might place unnecessary restrictions on the commercial relationships between GasNet and VENCorp.

The Draft Decision concluded that GasNet's access arrangement should continue to provide a reference service and, consequently, should include terms and conditions upon which those services are available. As the proposed revised access arrangement did not include terms and conditions, the Commission concluded that the Code requirements were not satisfied. Accordingly, the Commission proposed an amendment requiring the inclusion of the terms and conditions on which GasNet supplies the services to VENCorp (which in turn are set out in the SEA and MSOR).

11.2.6 Response to Draft Decision

VENCorp noted that while the Commission has not required GasNet to include the SEA in its revised access arrangement, it 'does require GasNet to include the terms and conditions on which GasNet supplies the services to VENCorp, which in turn are set out in the Service Envelope Agreement and the MSO Rules'.[696] In addition, it stated:

> VENCorp also notes that to date, confidentiality restrictions in the Service Envelope Agreement have impeded VENCorp sharing with Users the details of amendments made to that agreement. Therefore, VENCorp would support the Commission requiring both VENCorp and GasNet to publish or make available to Users the Service Envelope Agreement as in force from time to time.[697]

TXU also supported the proposal to make the SEA, as in force from time to time, public. It suggested that publication of the SEA could be achieved by placing an obligation on GasNet or by amending section 5.3.1(a) of the MSOR.

As noted by VENCorp, TXU stated that confidentiality restrictions in the SEA have prevented users access to details of amendments made to the SEA. Consequently, TXU suggested that the Commission 'consider requiring GasNet to ensure that there is a transparent and robust process around any SEA amendments'.[698]

EUCV also expressed support for the Commission's Draft Decision, noting that it considered that the access arrangements of GasNet and VENCorp must be 'seamless'.[699]

In response to the Commission's Draft Decision, GasNet reiterated its view that VENCorp is the party responsible for terms and conditions.[700]

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696 VENCorp submission, 13 September 2002, p. 6.

697 ibid.

698 TXU submission, 16 September 2002, pp. 8-9.

699 EUCV submission, 13 September 2002, p. 12.

700 GasNet submission, 20 September 2002, p. 41.

11.2.7 Final Decision

As noted above (in section 11.1.7), the Commission remains of the view that GasNet's revised access arrangement for the PTS should include, in the services policy, the service that GasNet supplies to VENCorp (that is, making the pipeline system available to VENCorp). This service is a 'reference service' in that GasNet's revised access arrangement sets out reference tariffs to be paid to GasNet by users of the pipeline system operated by VENCorp.

Following from this and section 3.6 of the Code, the Commission considers that the terms and conditions upon which GasNet makes the system available to VENCorp must be included in GasNet's revised access arrangement. These terms and conditions are contained in the MSOR and SEA.

While the MSOR, as in force from time to time, is a public document, a current SEA is not publicly available. VENCorp's amended services policy states that users must consult GasNet's access arrangement and the SEA to understand what GasNet must provide in order for VENCorp to deliver its reference services. The Commission has discussed this matter with both parties. GasNet and VENCorp have advised that they are willing for the SEA to be disclosed, including changes to the document as they occur from time to time. It is envisaged that GasNet will provide the current version of the SEA when it submits complying amended revisions to its access arrangement and that it will maintain a current copy of the SEA on its website.[701]

More generally, the Commission notes that GasNet has not identified any particular disadvantage that would arise from including the proposed terms and conditions in the revised access arrangement.[702] The Commission considers that its amendment to the terms and conditions is in the interest of users and prospective users (section 2.24(f)) and does not conflict with GasNet's legitimate business interests or contractual obligations (sections 2.24(a) and (b)) as it reflects GasNet's current obligations. The Commission is satisfied that if the terms and conditions are amended as specified they would meet the requirements of section 3.6 of the Code having regard to the factors in section 2.24. Accordingly, the Commission requires the proposed revised access arrangement for the PTS to be amended to include the terms and conditions on which GasNet makes the PTS available to VENCorp (being the terms and conditions as set out in the MSOR and SEA in force from time to time and made publicly available).

Amendment 44

GasNet must amend clause 8.1 of its revised access arrangement, terms and conditions, to state that the terms and conditions on which GasNet supplies the services to VENCorp are set out in the SEA and the MSOR in force from time to time. Clause 8.1 must also state that GasNet will make the SEA, as in force from time to time, publicly available.

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701 The Commission notes that certain elements of the SEA contain electronic memory intensive information including maps and other picture documents. The Commission does not expect such elements to be made available electronically to users and prospective users.

702 GasNet's submissions concern the earlier issue of whether its services policy should be amended to include the service that GasNet supplies to VENCorp.

11.3 Extensions and expansions policy

11.3.1 Code requirements

The Code requires an access arrangement to have an extensions and expansions policy (section 3.16). The policy is to set out the methodology used to assess whether any extensions to, or expansion of, the capacity of the system will be treated as part of the covered pipeline for the purposes of the Code.

A service provider is also required to specify the impact on reference tariffs of including an extension or expansion as part of the covered pipeline.[703] In addition, an extensions and expansions policy must outline under what conditions the service provider will fund any new facilities and provide a description of these new facilities.

11.3.2 Current access arrangement provisions

The current provisions of the PTS and WTS access arrangements state that all expansions to the systems will be covered by the relevant access arrangements. Significant extensions, that is where the cost is greater than $5 million or the extension is longer that 10 km, may be excluded from the relevant access arrangement if the service provider notifies the Commission, before the extension comes into service, that the extension will not form part of the access arrangement. The ability to elect coverage of an extension is not available for extensions that have been included in the calculation of reference tariffs or, pursuant to clause 5.7.1(f) of the PTS access arrangement, the Interconnect.

Regardless of whether an extension or expansion is to be included in an access arrangement, GasNet is required (under clause 5.7.1 of the PTS access arrangement) to notify the Commission of the location, cost and length of a new extension or expansion prior to it coming into service.

The cost of an extension or expansion will be included in the capital base if it passes the economic feasibility test (as determined by the Commission pursuant to a revision application under section 2.28 of the Code). Users will be charged the current reference tariff. Alternatively, the proportion of the cost that passes the economic feasibility test may be included in the capital base. The remaining proportion may be recovered by a surcharge, a capital contribution, included in the speculative investment fund, or any combination of these.

The policies also allow extensions and expansions that do not pass the economic feasibility test to be included in the capital base of the relevant access arrangement in some circumstances. The Commission must be satisfied that either system-wide benefits arise from the investment which justify higher tariffs for all users or that the investment is necessary on the basis of maintaining the safety, integrity or contracted capacity of the reference services.

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703 For example, reference tariffs may remain unchanged, but a surcharge may be levied on incremental users.

11.3.3 GasNet proposal

Consistent with the current provisions, GasNet proposes that all expansions to the pipeline system be included in the access arrangement. GasNet would continue to be required to notify the Commission of any new extension or expansion prior to it commencing service.

The first amendment proposed by GasNet is that the ability to exclude an extension from coverage of the access arrangement be provided for all extensions (with the exception of those included in the calculation of reference tariffs).[704]

GasNet considers that the current threshold test, which requires all small extensions to be included in the access arrangement, has the effect of deterring investment in small pipelines and is 'unduly restrictive'. GasNet states that:

> … extending coverage to small laterals is implicitly allowing for open access to these laterals. This is incompatible with the nature of those pipelines which are essentially service lines to a specific customer. GasNet is at a severe disadvantage in tendering to build these laterals as alternate pipeline companies can offer a dedicated pipeline to the prospective User.[705]

A service line is a pipeline from a shared pipeline to a specific end user. While many service lines are part of a distribution network, dedicated high pressure pipelines to large users will become part of a transmission system. GasNet states that in 1998 there were four service lines to single customers. There have since been two tenders, one of which GasNet won. GasNet expects approximately three service laterals to be required over the forthcoming access arrangement period.

GasNet regards the current policy as creating a situation where it is at a commercial disadvantage in tendering for service lines. Firstly, the user cannot obtain exclusive, or favoured, rights to the capacity of the service line under the market carriage system. Although it may be unlikely that a third party would seek to access a service line, GasNet considers that a user will see uncertainties in a GasNet bid to build a service line.

Secondly, GasNet considers it is restricted in the tariff proposal it is able to offer a potential user of a service line. As the lateral will become part of the covered pipeline and be included in the access arrangement under the current extensions and expansions policy, a tariff is to be described in terms of the relevant reference tariff and a surcharge. However, GasNet states that it is only able to make assumptions about the tariff and surcharge since they require approval by the Commission. Accordingly, GasNet considers that it is currently at a disadvantage to other pipeline businesses in tendering for service lines and seeks to remove the current policy that all small extensions become part of the covered pipeline and the access arrangement.[706]

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[704] GasNet has proposed to include forecast capital expenditure of approximately $1.5 million per year for small lateral pipelines. GasNet access arrangement information, 27 March 2002, p. 12. See section 6.3 of this Final Decision.

[705] GasNet submission, 27 March 2002, p. 113.

[706] GasNet response to Commission, 9 May 2002.

The second amendment for this policy proposed by GasNet is regarding the impact of extensions and expansions on reference tariffs. The current detailed clauses would be replaced with a clause stating that GasNet may submit revisions to the Commission seeking to include the costs of extensions and expansions in the capital base. These revisions would only be considered under the relevant provisions (that is, sections 8.15 and 8.16) of the Code.

GasNet proposes to retain the ability to undertake new facilities investment that does not satisfy section 8.16 of the Code.

11.3.4 Submissions to Issues Paper

GasNet's proposal to include all expansions in the access arrangement received little comment from interested parties with the exception of VENCorp which stated that 'there should be no room for discretion regarding expansions'.[707] In addition, VENCorp suggested that the access arrangement should make explicit provision for any expansion to the pipeline system to be 'dealt with under the Service Envelope Agreement and MSO Rules, as it does in its current access arrangement'.[708]

ENERGEX stated that it 'does not agree that GasNet should have unilateral rights to determine whether future extensions should be covered'.[709] It noted that the Code and the Commission have processes in place to assess extensions and indicated that these should be followed.

EnergyAdvice expressed concern regarding the impact of the proposed extensions and expansions policy on new laterals dedicated to end users. In a scenario where an end user pays GasNet the capital cost of building a lateral and the lateral becomes part of the covered pipeline, EnergyAdvice is concerned that the end user will not obtain 'absolute capacity rights'. It also suggested that third party users will have access to the lateral 'but are not required to reimburse the initial end user'.

Alternatively, EnergyAdvice noted that the end user could contract with a party other than GasNet to build the lateral and then arrange for the operation of the pipeline with GasNet. While this provides the end user with exclusive rights to the lateral, EnergyAdvice suggested that this option is not favoured 'as it is a cumbersome alternative and excludes others that could be supplied using spare capacity'. EnergyAdvice concluded:

> There needs to be a balance between protecting foundation end users who pay for or contribute to the cost of pipelines, access provisions that are equitable, and conditions that encourage efficient capital expenditure. We doubt that the current policy achieves this.[710]

11.3.5 Draft Decision

As noted in section 11.3.3 above, GasNet proposed to continue with the current policy that all expansions be included in the access arrangement. The Commission noted that,

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707 VENCorp submission, 13 May 2002, p. 15.

708 ibid., p. 15. TXU also expressed this view: TXU submission, 31 May 2002, p. 38.

709 ENERGEX submission, 9 May 2002, p. 5.

710 EnergyAdvice submission, 30 May 2002, p. 11.

generally, it prefers this approach and agrees with VENCorp's view that it is not appropriate to have discretion regarding new expansions of a pipeline system.[711]

The Commission noted VENCorp's suggestion that GasNet's extensions and expansions policy currently explicitly provides that expansions will be dealt with under the SEA and the MSOR and that this should continue. However, GasNet's extensions and expansions policy does not currently provide for this. The Commission understands that the current SEA provides for the inclusion of extensions and expansions to the pipeline system in the SEA so that an accurate SEA remains in effect between GasNet and VENCorp. This is also reflected in chapter 5 of the MSOR. The Commission noted that it is not aware that these clauses have been inadequate during the initial access arrangement period with respect to the relationship between GasNet and VENCorp. Accordingly, the Commission did not propose to amend the access arrangement as suggested by VENCorp and TXU.

GasNet suggested that it may face difficulties in tendering for service lines in the future if the current threshold assessment of extensions remains in place. EnergyAdvice has also expressed concern regarding the impact on users of service lines. The Commission stated that it is not convinced that the current policy places GasNet at a significant disadvantage as it suggests. Similarly, the Commission did not consider that users of service lines are under significant disadvantage pursuant to the current policy. It did agree with EnergyAdvice however, that a balance between foundation users and third party users should be found.

While the issue has not been raised by GasNet or in submissions, the Commission noted that automatic coverage of an extension may complicate any bids by GasNet under the competitive tender provisions of the Code.

The Draft Decision concluded that it is appropriate for a service provider to retain discretion as to whether extensions to its pipeline system become part of the covered pipeline and be included in the relevant access arrangement. Accordingly, the Commission proposed to accept GasNet's proposed revisions to the current extensions and expansions policy to this effect.

It was noted in the Draft Decision in relation to the concerns raised by ENERGEX, that any extension that a service provider seeks to include in an access arrangement would be required to satisfy the requirements of section 8.16 of the Code. In addition, it may be possible to regard an extension as a separate pipeline, allowing any party to apply to the National Competition Council for coverage under the Code. The revised extensions and expansions policy would not circumvent these Code provisions.

The second set of proposed revisions to the extensions and expansions policy relate to the tests that new facilities investments must satisfy in order to be incorporated into the capital base. The Commission stated that it had found that the current provisions of the access arrangements are more restrictive than the new facilities investment provisions of the Code. The current access arrangement provisions only provide for a partial inclusion of a new facilities investment into the capital base under the economic

[711] See ACCC, *Final Decision: access arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, 12 September 2001, pp. 170-172.

feasibility test. Partial roll-in of costs to the capital base and use of the speculative investment fund are not available under the system-wide benefits or safety and integrity tests. In contrast, the Code does not preclude partial roll-in of costs to the capital base under any of the three tests of section 8.16(b).

The Draft Decision noted that the service provider may have considered this limitation appropriate at the time of the initial assessment of the access arrangement and the Commission had accepted this. However, the more restrictive provisions currently contained in the access arrangements are not necessary. The new facilities investment provisions of the Code are appropriate. Consequently, the Commission proposed to accept this proposed revision to the access arrangements.

11.3.6 Response to the Draft Decision

GasNet acknowledged the Commission's draft decision to accept the proposed revisions to the extensions and expansions policy of the PTS access arrangement.[712] No other comments were received on this policy.

11.3.7 Final Decision

As discussed above in section 11.3.5, the Commission's Draft Decision proposed to accept the proposed revisions to the extensions and expansions policy for the PTS. No new information has emerged to indicate that this decision was inappropriate and should be revised. Accordingly, for the reasons discussed above, the Commission's decision is that it does not require any amendment to the proposed revised extensions and expansions policy for the PTS.

11.4 Review of the access arrangement

11.4.1 Code requirements

Section 3.17 of the Code requires an access arrangement to include a date upon which the service provider must submit revisions to its access arrangement to the regulator (revisions submission date). The access arrangement must also include a date upon which the revisions are intended to commence (revisions commencement date).[713]

The regulator's assessment of the appropriateness of the two dates must include reference to the objectives contained in section 8.1 of the Code. The regulator may, with reference to these objectives, require an earlier or later revisions submission date or revisions commencement date. It may also require that a specific major event be a trigger that compels the service provider to submit revisions prior to the revisions submission date.

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712 GasNet submission, 20 September 2002, p. 42.

713 Revisions come into effect on the date specified by the regulator in its decision to approve the revisions, which must be at least 14 days after the decision, or the revisions commencement date. Section 2.48 of the Code.

11.4.2 Current access arrangement provisions

The current provisions of the access arrangements specify 31 March 2002 as the revisions submission date and 1 January 2003 as the revisions commencement date. The Tariff Order states that the second access arrangement period will expire on 31 December 2007.

11.4.3 GasNet proposal

GasNet proposes that the new revisions submission date be 31 March 2007 and the revisions commencement date be 1 January 2008. If the revised access arrangement commences on 1 January 2003 as currently proposed the new access arrangement period will be five years.

GasNet has noted in its submission that a five year period is consistent with general regulatory practice and, in particular, coincides with the expiration of the SEA with VENCorp. In addition, it notes that the Tariff Order defines 'subsequent access arrangement period' as being five years from 1 January 2003.[714]

Clause 5.9 of the proposed revised VENCorp access arrangement specifies the same revisions submission date and revisions commencement date.

11.4.4 Submissions to Issues Paper

The Commission did not received any submissions regarding this aspect of the proposed revisions.

11.4.5 Draft Decision

The Commission considered the appropriateness of the two dates in terms of the objectives contained in section 8.1 of the Code and determined that a five year access arrangement period is consistent with these objectives.

The Commission noted that the ESC draft decision for the Victorian gas distributors proposed that the revisions assessment period should be extended by two months by amending the revisions submission date. However, the Commission considered that a nine month assessment period should be adequate for the next scheduled review of GasNet's access arrangement. Accordingly, the Commission proposed to accept the proposed revisions submission date and revisions commencement date.

11.4.6 Response to Draft Decision

The Commission has not received any comments from interested parties regarding this policy of the proposed revised access arrangement.

[714] GasNet submission, 27 March 2002, p. 127.

11.4.7 Final Decision

The Commission notes that the ESC final decision indicates that it has accepted the arguments put forward by the distributors for a nine month assessment period and consequently, no longer requires an amendment to the access arrangements.[715]

The Commission considers that the revisions submission date and revisions commencement date proposed by GasNet are appropriate and provide a suitable time frame to assess the proposed revisions to the access arrangement. As noted in the Draft Decision, GasNet has the discretion to submit its revisions at an earlier date if it considers this is warranted. Accordingly, for the reasons outlined above and set out in the Draft Decision, the Commission does not require an amendment to this aspect of the revised PTS access arrangement.

11.5 Other non-tariff issues

The Code also requires an access arrangement to contain a capacity management policy, a trading policy and a queuing policy. These policies relating to GasNet's proposed revised access arrangement are discussed together in this section.

11.5.1 Code requirements

The Code (sections 3.7 and 3.8) requires that an access arrangement specify the capacity management policy that applies to the pipeline. The pipeline must be either a contract carriage pipeline or a market carriage pipeline. If the pipeline is to operate as a market carriage pipeline then consent from the relevant minister must be obtained and provided to the regulator.

If a pipeline is a contract carriage pipeline then the access arrangement must include a trading policy that explains the rights of users to trade their rights to obtain a service with other users (see section 3.9 of the Code).

Pursuant to sections 3.12 to 3.15 of the Code, an access arrangement must include a queuing policy. This policy is to be used to determine 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.

11.5.2 Current access arrangement provisions

Clause 5.5 of the current PTS access arrangement states that the pipeline is a market carriage pipeline. Consequently, it does not include a trading policy. The responsibility for establishing a queuing policy for the pipeline is currently allocated to VENCorp under clause 5.6 of the PTS access arrangement.

Clause 5.5 of the current WTS access arrangement states that the pipeline is a contract carriage pipeline. It also foreshadows that the WTS will become a market carriage

[715] ESC, *Final Decision: review of gas access arrangements*, October 2002, p. 273.

pipeline following the construction of the Southwest Pipeline by which it will connect to the PTS.

The current WTS access arrangement also includes a trading policy and queuing policy. Both of these policies were found to meet the requirements of the Code by the Commission in its initial assessment of the access arrangement.

11.5.3 GasNet proposal

Clause 8.2 of the proposed revised access arrangement states that the PTS (which includes the pipelines formally referred to as the PTS and WTS) is a market carriage pipeline. Both the NSW and Victorian Ministers have consented to this capacity management policy applying for the duration of the forthcoming access arrangement period.[716]

Clause 8.3 of the proposed revised access arrangement states that the responsibility for complying with the trading policy requirements of the Code is allocated to VENCorp. However, GasNet's submission notes that, as the pipeline is a market carriage pipeline, a trading policy is not required.[717]

The queuing policy obligations for the PTS would continue to be allocated to VENCorp.

11.5.4 Submissions to Issues Paper

No substantive issues have been raised by interested parties regarding these policies.

11.5.5 Draft Decision

The Commission proposed to accept that the current capacity management policy of market carriage continues to apply for the PTS. In forming one pipeline system from the former PTS and WTS, the WTS will become a market carriage pipeline. The Commission considered that this was appropriate and noted that it has received copies of the ministerial letters of consent pursuant to section 3.8 of the Code from the relevant Victorian and NSW ministers. The Draft Decision noted that the most appropriate forum to review the appropriateness of the market carriage system would be the forthcoming review pursuant to the Victorian GIA.

As raised by VENCorp in its proposed revised access arrangement, the Code does not require a trading policy for the pipeline. While GasNet acknowledged this in its submission, its proposed revised access arrangement incorrectly states that VENCorp has responsibility for a trading policy. Accordingly, the Commission proposed an amendment in its Draft Decision to correct this anomaly.

The Commission agreed that it is appropriate that VENCorp continues to be responsible for the PTS queuing policy. This policy is set out in section 5.7 of the

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716 ibid., p. 126.

717 ibid., p. 126.

proposed revised access arrangement lodged by VENCorp and clause 5.3 of the MSOR.

11.5.6 Response to the Draft Decision

The Commission has not received any comments from interested parties regarding these policies of the proposed revised access arrangement. In addition, GasNet has not responded to the proposed amendment relating to trading policy.

11.5.7 Final Decision

As discussed in the Draft Decision, the Commission considers that the appropriate capacity management policy for the PTS during the second access arrangement period is market carriage.

The Commission considers that clause 8.3 of GasNet's proposed revised access arrangement is not a correct reflection of the trading policy requirements specified in the Code. To clarify the matter, the Commission considers that it would be appropriate for GasNet to amend this clause.

Amendment 45

GasNet must amend clause 8.3 of its revised access arrangement to remove the current purported allocation of responsibility of a trading policy to VENCorp.

The Commission agrees that the allocation of the queuing policy for the PTS to VENCorp is appropriate.

Part D – Decision

12. Decision

The Commission has carefully considered GasNet's proposals, submissions by interested parties and the current provisions of GasNet's access arrangements. The Commission has explicitly commented on the issues and arguments raised where this has been considered appropriate, however it does not consider it practical to explicitly comment on or respond to all comments made in order to meet the principles and objectives set out in the Code.

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 the factors set out in section 2.24 into account when exercising discretion. The Commission's considerations of these assessments are summarised in earlier sections of this Final Decision.

Pursuant to section 2.38(a)(ii) of the Code, the Commission has decided not to approve the proposed revised access arrangement for the GasNet System lodged by GasNet Australia (Operations) Pty Ltd. 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 revised access arrangement are identified in the relevant sections of this Final Decision document and are listed below. GasNet must submit amended revisions to the Commission by 2 December 2002.

Amendment 1

GasNet must amend clause 4.6 of its revised access arrangement so that the redundant capital policy applies to both partially and wholly redundant assets.

Amendment 2

GasNet must amend its revised access arrangement by removing clause 4.10.

Amendment 3

GasNet must amend the following in its revised access arrangement:

- the definition of a Change in Taxes Event in clause 9.1 so that (b) reads 'the removal or imposition of a Relevant Tax';
- the definition of a Regulatory Event in clause 9.1 to allow for regulatory requirements that may result in either higher or lower costs for GasNet;
- the definition of an Insurance Event in clause 9.1 to allow for a changes in the Minimum Insurance Level that exceed or fall short of the Benchmark Insurance Costs; and
- the definition of an Insurance Event in clause 9.1 to include the amounts currently identified in the asymmetric risk allowance as deductibles in current insurance.

GasNet must also amend clause 6.4 of its revised access arrangement to allow both positive and negative pass through amounts.

Amendment 4

GasNet must amend the definition of a Relevant Tax in clause 9.1 to read the as follows.

Relevant tax means any tax, (including any rate, duty, charge, levy or other like or analogous impost paid or taken to be paid by GasNet associated with the Tariffed Transmission Service), but excludes:

(1) income tax (or State equivalent tax) and capital gains tax;

(2) penalties and interest for late payment relating to any tax, rate duty, charge, levy or analogous impost;

(3) fees and charges paid or payable in respect of a *Regulatory Event*,

(4) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties; and

(5) any tax, rate, duty, charge, levy or other like or analogous impost which replaces the taxes and charges referred to in (1) to (4).

Amendment 5

GasNet must amend clause 6.2(b) of its revised access arrangement to provide an assessment period of 40 business days and to allow the Commission, at its absolute discretion, to extend the period by a further 40 day period on one or more occasion where it considers it necessary to adequately assess the pass through proposal. Clause 6.1 of its revised access arrangement should also be amended so that:

- GasNet is obliged to submit a Pass Through Event statement to the Commission at least 50 business days prior to the start of the regulatory year;
- the statement must detail all Pass Through Events which have occurred in that period (ending on the date specified in the statement) but not previously notified to the Commission and provide the information described in 6.1(a) to (e) of the revised access arrangement for those events; and
- where no Pass Through Events have occurred for the relevant period, this should be stated.

Amendment 6

GasNet must amend:

- clauses 4.5, 4.6 and 4.7 in Schedule 4 and clauses 6.4 and 6.5 of its revised access arrangement to allow any approved pass through amounts to be recovered (paid back) through the average revenue control mechanism;
- clauses 6.2 and 6.3 to specify that pass through amounts must have been incurred by GasNet in the 2003 to 2007 access arrangement period; and
- schedule 4 to allow for a carryover in the third access arrangement period for any pass through amounts incurred in 2003 to 2007 period but not recovered (paid back) in that period.

Amendment 7

GasNet must amend:

- clauses 6.1 and 6.2 of its revised access arrangement to require the provision, at least 50 business days before the start of a regulatory year, of sufficient detailed documentary evidence which substantiates that the aggregate costs facing GasNet have increased or decreased as a consequence of the alleged pass through event.
- clause 6.1 of its revised access arrangement to require GasNet to provide the Commission with a copy of insurance premium invoices annually at least 50 business days before the start a regulatory year, irrespective of whether a pass through event statement is submitted.

Amendment 8

GasNet must calculate the roll forward of the regulatory asset base on the basis of the initial capital base of $358.0 million (at 1 January 1998) which was approved in the 1998 Final Approval.

Amendment 9

GasNet must calculate the roll forward of the regulatory asset base without any adjustment to the proportion of indirect assets included.

Amendment 10

GasNet must use an inflation rate for 2002 in the calculation of the RAB which is based on the index numbers published by the ABS for the CPI, all groups, weighted average of 8 capital cities and uses an estimate for the fourth quarter based on the Fisher equation estimate of 2.16 per cent per annum.

Amendment 11

GasNet must amend Schedule 1 if its revised access arrangement to include tariffs for the Southwest Pipeline which are approximately 10 per cent higher than those on the Longford to Pakenham Pipeline, consistent with $42.5 million being recovered under each of the economic feasibility and system-wide benefits tests. An incremental tariff is to apply on the Southwest Pipeline. Recovery of costs included under the system-wide benefits test is to be by an equal dollar increase in the withdrawal tariffs.

Amendment 12

GasNet must adopt a value of 2.16 per cent for expected inflation for the period 2003 to 2007 in its revised access arrangement.

Amendment 13

GasNet must adopt the Commission's CAPM parameters as set out in Table 5.3 of this Final Decision to more accurately reflect the current financial market settings. GasNet must use the real vanilla WACC of 6.30 per cent to calculate the return on asset component of revenues for its revised access arrangement.

Amendment 14

GasNet must amend clause 3.5 of its revised access arrangement information to exclude litigation costs from operations and maintenance cost forecasts. In addition, litigation costs must not be incorporated in the pass through mechanism.

Amendment 15

GasNet must amend clause 3.5 of its revised access arrangement information so that an inflation estimate of 2.16 per cent is used when calculating all operations and maintenance cost forecasts in the second access arrangement period.

Amendment 16

GasNet must amend clause 3.5 of its revised access arrangement information to include an allowance of $22 622 in 2003 and $45 244 in 2004-2007 (2003 dollar terms) in operations and maintenance cost forecasts associated with additional gas chromatographs.

Amendment 17

GasNet must amend clause 3.5 of its revised access arrangement information so that operations and maintenance cost benchmarks for the second access arrangement period only include 88.23 per cent of total general and administrative cost forecasts.

Amendment 18

GasNet must amend clause 3.5 of its revised access arrangement information to only incorporate a total of $1 730 634 (in 2003 dollars) per year for insurance in 2003 operations and maintenance cost forecasts.

Amendment 19

GasNet must amend clause 3.5 of its revised access arrangement information to incorporate regulatory review costs of $1 051 938 in 2003 dollar terms. GasNet must not incorporate forecast regulatory review costs for 2006 and 2007 in benchmark revenues.

Amendment 20

GasNet must amend section 3 of its revised access arrangement information to include an allowance for equity raising costs of 0.0224 per cent of regulated equity, to be recovered as an annual non-capital cost cash flow. It must also amend its revised access arrangement to exclude an allowance for debt raising costs in non-capital expenditure cash flows and add 12.5 basis points to the debt margin for these costs.

Amendment 21

GasNet must amend section 3.5 of its revised access arrangement information so that the estimated K factor under-recovery to be carried forward is $12 903 127 in 2003 dollar terms.

Amendment 22

GasNet must amend clause 4.9 of Schedule 4 of its proposed revised access arrangement to remove 'Step 2' of the rebalancing control formula.

Amendment 23

GasNet must revise the calculation of the K factor adjustment so that peak volumes (forecast and actual) associated with the Southwest Pipeline are deemed to be associated with the Longford injection pipeline. If this revision is demonstrated to be impractical, GasNet must remove all injection pipelines from the K factor mechanism.

Amendment 24

GasNet must revise the calculation of the K factor adjustment so that, for the annual volumes (forecast and actual) associated with the Murray Valley Pipeline, the applicable tariff is not the complete Murray Valley tariff but the portion covering system costs of transportation to Chiltern Valley.

Amendment 25

GasNet must include in clause 4, reference tariff policy, of its revised access arrangement:

- explicit confirmation that the business will self-insure;
- details that clearly specify the self-insured risks consistent with this Final Decision; and
- explicit confirmation that future actual costs relating to these identified events will not be included in future regulatory cash flows.

If GasNet does not accept these inclusions in clause 4, then GasNet must remove all allowances for asymmetric risk from its revenue calculations.

Amendment 26

GasNet must amend clause 3.5 of its revised access arrangement information so that the total annual allowance for asymmetric risks is $22 000 (in 2003 dollars) for each year of the access arrangement period.

Amendment 27

GasNet must amend clause 3.5 of its access arrangement information so that in calculating a return on linepack and spare parts, GasNet must base the valuation of the items on historical expenditure and must use a valuation approach (nominal or real) consistent with the vanilla WACC to be applied. The value of spare parts not associated with regulated services must be removed from the calculations.

Amendment 28

GasNet must amend section 3.6 of its revised access arrangement information to exclude from the calculation of tariffs forecast expenditure relating to the Brooklyn loop, stage two of the proposed Lurgi pipeline rehabilitation project, and possible service lines.

Amendment 29

GasNet must amend clause 3.6 of its revised access arrangement information to include the approved forecast capital expenditure for the three proposed gas chromatographs. It must also reflect the expected inflation rate specified in the Final Decision. These changes must also be incorporated into the revenue model used to determine reference tariffs for 2003 to 2007.

Amendment 30

GasNet must amend clause 3.3 of the revised access arrangement information regarding depreciation to reflect the Final Decision. These changes must also be included in the revenue model used to determine reference tariffs.

Amendment 31

GasNet must correct its revenue model so that no return on capital or depreciation is calculated on capital expenditure in the year in which it is forecast to occur. Capital expenditure should be added to the opening balance of the asset base in the subsequent year at the forecast mid-year expenditure amount (as currently provided to the Commission) inflated to the end of the year.

Amendment 32

GasNet must amend section 4 of its revised access arrangement information to include forecast flows from the Yolla field in its flow assumptions from 2004.

Amendment 33

GasNet must amend section 5.3 of its revised access arrangement information to allocate the K factor under-recovery of $12 903 127 (in 2003 dollars) to all tariffs (other than those for the Southwest Pipeline) as a uniform percentage increase.

Amendment 34

GasNet must amend section 5.3 of its revised access arrangement information to allocate capital raising costs on the same basis as it allocates depreciation and return on capital.

Amendment 35

GasNet must amend clause 1.3(g), schedule 1 of its revised access arrangement (as amended in September 2002) to require the provision of sufficient evidence to the Commission to support a claim that a specific bypass threat is credible. In addition, it must state that the introduction of the Warrnambool and Koroit prudent discounts would be subject to the Commission's approval.

Amendment 36

In calculating tariffs, GasNet must amend its proposed revised access arrangement to calculate a tariff for Murray Valley users which is a combination of an incremental tariff for the Murray Valley Pipeline and a tariff for system usage to Chiltern Valley. These tariffs must be based on the standard cost allocation methodology (as expressed in GasNet's submission of 24 October 2002) except that GasNet must allocate 75 per cent (rather than 100 per cent) of Murray Valley costs to users on the basis of peak usage and 25 per cent on the basis of annual usage.

Amendment 37

GasNet must replace the proposed X of five per cent in schedule 1 of the revised access arrangement with an X of three per cent.

Amendment 38

GasNet must amend schedule 3 to its revised access arrangement so that the annual tariff review time frames currently in clause 6.1 of the Tariff Order are retained. GasNet must also include the provisions currently in clauses 6.1(a)(1)(B) and 6.1(f)(2) of the Tariff Order in schedule 3 to its revised access arrangement.

Amendment 39

GasNet must amend section 3.5 of the access arrangement information to include actual historical operations and maintenance costs for each of the years 1998 to 2001, and current best estimates for 2002.

Amendment 40

GasNet must amend clause 7.2 of its revised access arrangement so that the benefit sharing allowance for operations and maintenance costs calculated for the third access arrangement period is based on the rolling carryover mechanism. The amendment must:

- allow GasNet to keep unanticipated efficiency gains (losses) for the year that they are implemented and for an additional five years;
- allow for the carryover of both unanticipated gains and losses;
- determine operations and maintenance expenditure achieved by GasNet in 2007 by taking 2006 actuals and adjusting these by the change in expenditure which is forecast to occur between 2006 and 2007;
- not allow for volume growth, except for operations and maintenance costs associated with capital expenditure deemed prudent and rolled into the asset base;
- adjust second period forecast costs for any positive or negative pass through events that may occur within the period;
- adjust second period forecast costs for regulatory review expenses; and
- ensure that all amounts are expressed in 2008 dollars.

Amendment 41

GasNet must amend section 3.5 of its revised access arrangement information to remove any benefit sharing allowance associated with the first access arrangement period.

Amendment 42

GasNet must amend section 6 of its access arrangement information to include operations and maintenance costs/km/PJ data in its comparison of Australian KPIs.

Amendment 43

GasNet must amend clause 3 of its revised access arrangement, services policy, to include the services that GasNet supplies to VENCorp (that is, making the PTS available to VENCorp in accordance with the SEA and the MSOR). In addition, the reference ‘VENCorp Services’ in clause 3.2 must be changed to ‘VENCorp Reference Services’.

Amendment 44

GasNet must amend clause 8.1 of its revised access arrangement, terms and conditions, to state that the terms and conditions on which GasNet supplies the services to VENCorp are set out in the SEA and the MSOR in force from time to time. Clause 8.1 must also state that GasNet will make the SEA, as in force from time to time, publicly available.

Amendment 45

GasNet must amend clause 8.3 of its revised access arrangement to remove the current purported allocation of responsibility of a trading policy to VENCorp.

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

TXU Australia	3 May 2002
ENERGEX Retail	9 May 2002
AGL Energy Sales and Marketing	9 May 2002
VENCorp	13 May 2002
Duke Energy International	13 May 2002
Pulse United Energy	16 May 2002
Origin Energy	17 May 2002
BHP Billiton	17 May 2002
Victorian Department of Natural Resources and Environment	20 May 2002
EnergyAdvice[718]	30 May 2002
TXU	31 May 2002
Energy Action Group	31 May 2002
Energy Users Association of Australia	4 June 2002
The Allen Consulting Group[719]	5 June 2002
ExxonMobil Gas Marketing	5 June 2002
BHP Billiton	21 June 2002
Amcor and PaperlinX	24 June 2002
Energy Users Association of Australia	11 July 2002
BHP Billiton	18 July 2002
Bob Lim & Co and Headberry Partners[720]	30 July 2002

718 On behalf of ACI Glass Packaging, Barrett Burston, Bonlac Foods, Cabot, CSR Limited, Insulation Solutions, Mobil Altona Refinery, Norske Skog, Overall Forge, Pilkington Glass, Qenos, Tatura Milk.

719 On behalf of ExxonMobil.

720 On behalf of BHP Billiton Petroleum and Electricity Consumers Coalition of South Australia.

Post Draft Decision

Exxon Mobil Gas Marketing	10 September 2002
AusCID	12 September 2002
VENCorp	13 September 2002
Australian Gas Association	13 September 2002
BHP Billiton	13 September 2002
NECG	13 September 2002
Energy Users Coalition of Victoria	13 September 2002
Amcor PaperlinX	13 September 2002
TXU	16 September 2002
Origin	18 September 2002
AGL	18 September 2002
Energy Advice	19 September 2002
GasNet Australia	20 September 2002
Energy Users Association of Australia	20 September 2002
Santos	20 September 2002
Customer Energy Coalition	8 October 2002
Energy Users Coalition of Victoria	9 October 2002
Amcor and PaperlinX	10 October 2002
BHP Billiton	11 October 2002
EnergyAdvice	18 October 2002

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.

Dr Martin Lally, *Determining the risk free rate for regulated companies*, July 2002.

Appendix D: Map of GasNet system