APA Group

GasNet Access Arrangement Submission

Dated: 14 May 2007

GasNet Access Arrangement Submission
Contents

1	**Executive Summary**	**4**
1.1	Background	4
1.2	Impact of instability in the regulatory environment	4
1.3	Forecast capital expenditure - Maintaining Victoria's gas reliability	5
1.4	A simpler and more transparent tariff	5
1.5	Otherwise, business as usual	5
PART A - INTRODUCTION		**7**
2	**Background**	**7**
2.1	Purpose	7
2.2	The Market Carriage System	7
2.3	National energy market reforms	9
3	**GasNet System**	**10**
3.1	Background	10
3.2	Description of GasNet System	10
3.3	Service Envelope Agreement	11
PART B - TARIFF ISSUES		**13**
4	**Reference Tariff Principles**	**13**
4.1	Summary of GasNet's Proposal	13
4.2	Code Requirements	13
4.3	Reference Tariff Methods	14
4.4	Reference Tariff Method	15
5	**Establishing the Capital Base**	**16**
5.1	Summary of GasNet's Proposals	16
5.2	Code requirements	17
5.3	Capital Base at commencement of Second Access Arrangement Period	18
5.4	Redundant Capital	18
5.5	New Facilities Investment – summary of forecast vs actual	19
5.6	Code requirements for New Facilities Investment and application of requirements	23
5.7	Actual New Facilities Investment (projects forecast in 2002)	24
5.8	Actual New Facilities Investment (projects not forecast in 2002)	27
5.9	Brooklyn Lara (Corio) Pipeline	31
5.10	Depreciation 2003-2007	31
5.11	Inflation 2003-2007	32
6	**Rate of Return**	**33**
6.1	Summary of GasNet's Proposals	33
6.2	Code requirements	33
6.3	Approaches to the Rate of Return	33
6.4	WACC parameters	34

6.5	Risk free interest rate	35
6.6	Inflation forecast	36
6.7	Cost of debt	36
6.8	Market risk premium	38
6.9	Gearing	38
6.10	Imputation credits (Gamma)	39
6.11	Tax allowances and normalisation	39
6.12	Equity beta	40
6.13	Bias in Inflation Forecasts	40
6.14	Specific risks	42
7	**Forecast capital expenditure**	**43**
7.1	Summary of GasNet's proposals	43
7.2	Code requirements	44
7.3	GasNet's proposal	44
7.4	Application of section 8.16 tests	46
7.5	Proposed augmentation projects	48
7.6	Refurbishment and Upgrade projects	54
8	**Other capital elements**	**60**
8.1	Code requirements	60
8.2	Depreciation	60
8.3	Inflation	63
9	**Non Capital Costs**	**64**
9.1	Code requirements	64
9.2	GasNet's proposal	64
9.3	Operating costs	65
9.4	K factor carry over	77
9.5	Application of benefit sharing allowance	78
9.6	Asymmetric risks	79
9.7	Equity raising costs	81
9.8	Other allowances (cost of maintaining linepack and inventories)	81
10	**Volumes and Calculation of Total Revenue**	**83**
10.1	Calculation of Total Revenue	83
10.2	Forecast Volumes	87
11	**Determination of Reference tariffs**	**93**
11.1	Background to tariff methodology	93
11.2	Tariff revisions 2008-2012	94
11.3	Proposed cost allocation and tariff setting	95
11.4	Rationale behind proposed changes	97
11.5	Peak pricing	100
11.6	Other Tariff Elements	102
11.7	Prudent Discounts	103
11.8	Tariff path - revenue control	104
11.9	Incentive Mechanism	107
11.10	Pass through events	109
PART C - NON-TARIFF ISSUES		**110**
12	**Non-tariff elements**	**110**
12.1	Allocation of responsibilities	110

12.2 Services Policy 110
12.3 Terms and conditions of service 111
12.4 Capacity management policy 111
12.5 Trading policy 111
12.6 Queuing policy 111
12.7 Extensions and expansions policy 111
12.8 Capital Redundancy 112
12.9 Review and expiry of Access Arrangements 112

13 KPIs 113

13.1 Code requirements 113
13.2 KPI concepts 113
13.3 KPIs 114

14 Glossary 117

14.1 Definitions 117

15 List of Schedules 121

16 List of Attachments 122

1 Executive Summary

1.1 Background

The PTS is the primary transmission system for the delivery of gas throughout Victoria, transporting around 220 PJ of gas each year (over 95% of Victoria's gas demand).

At present there are two Service Providers (as defined in the Code) with respect to the PTS. GasNet owns the PTS and is responsible for its maintenance. VENCorp (a State Government authority) is the operator of the PTS under the Market Carriage system established in Victoria under the MSO Rules.

On 23 December 2003, the Second Access Arrangement lodged by GasNet governing access to the PTS was approved by the Commission. This Submission supports GasNet's proposed revisions to the Second Access Arrangement. Subject to approval by the Regulator, these proposed revisions will take effect on 1 January 2008.

This Submission deals only with the proposed draft GasNet Access Arrangement. The proposed VENCorp Access Arrangement for the Third Access Arrangement Period will be the subject of a separate submission by VENCorp.

1.2 Impact of instability in the regulatory environment

GasNet is submitting its draft Access Arrangement at a time of instability in the governing regulatory environment - both for the gas industry generally and, specifically, for the gas industry in Victoria.

In particular:

(a) significant changes are already underway in relation to existing regulation of the gas industry at a national level; and

(b) at the same time, fundamental changes are being considered by the Victorian State Government in relation to the role of VENCorp vis a vis the Access Arrangement and in relation to the nature of the legal relationship between GasNet, VENCorp and other users of the PTS.

GasNet understands the intention is for transitional arrangements to be put in place in relation to the national gas changes such that any Access Arrangements already existing under the Code, or under review at the time the changes come into effect, would be "grandfathered". However, sufficient certainty on these proposed transitional arrangements has not yet been provided.

Further, the changes being considered in relation to the role of VENCorp have not yet been announced - let alone been subjected to the level of consultation and scrutiny that would be required before such fundamental changes could be implemented.

Given the uncertainty surrounding these anticipated changes, GasNet submits its draft Access Arrangement on the basis that the status quo remains. However, GasNet reserves its rights to review and resubmit on impacted elements of its draft Access Arrangement, both in respect of the Victorian regime and also any shortfalls in respect of the grandfathering of the national regime as and when additional clarity and sufficient certainty on the anticipated changes have been provided. This is due to the potentially significant impact on GasNet of the anticipated changes.

1.3 Forecast capital expenditure - Maintaining Victoria's gas reliability

Following privatisation of the Victorian gas system in the 1990s, the PTS has evolved from two separate gas transmission pipelines (the PTS and WTS) to a complete, integrated transmission network.

Unlike previous Access Arrangements Periods (where a relatively small amount of capital expenditure was required), GasNet is forecasting significant New Facilities Investment in the Third Access Arrangement Period. This is due to:

(a) the age of the components making up the PTS; and

(b) the fact that the excess capacity existing at the time of privatisation is close to being fully utilised.

As a result, as outlined in this Submission, GasNet anticipates constraints in the PTS during (and beyond) the Third Access Arrangement Period.

In order to ensure that the PTS continues to operate in accordance with accepted good industry practice and in accordance with GasNet's legal, regulatory and contractual obligations, a significant amount of capital expenditure will be required during the Third Access Arrangement Period.

1.4 A simpler and more transparent tariff

GasNet has proposed changes to the Current Tariff Model that will result in a simpler and more transparent tariff. This will be to the benefit of Users and end users of the PTS. The proposed model creates greater stability, certainty and robustness of tariffs going forward.

1.5 Otherwise, business as usual

Aside from the forecast capital expenditure requirements and the changes to the Tariff Model referred to above, it is effectively business as usual for GasNet during the Third Access Arrangement Period.

That is, the proposed draft Access Arrangement maintains most elements of the current approved Access Arrangement. The only other revisions proposed are some fine-tuning of particular elements based on GasNet's actual experience during the current Access Arrangement Period.

In particular, the draft Access Arrangement comprises:

(a) retention of the Building Block Methodology for determining Total Revenue;

(b) establishment of the Capital Base in accordance with the requirements of the Code and the Second Access Arrangement;

(c) adoption of the WACC parameters previously adopted by the Regulator;

(d) maintenance of the current positions on asset lives;

(e) application of the Fixed Principles under the Second Access Arrangement for calculation of forecast operating costs, and no significant departures in relation to other Non Capital Costs;

(f) a tariff path approach and a revenue control model adapted from the Second Access Arrangement, but which more adequately reflects the risk assumed by GasNet in operating the PTS; and

(g) inclusion of an incentive mechanism that is consistent with the Second Access Arrangement subject to certain amendments aimed at addressing unintended impacts in the specific methodology.

PART A - INTRODUCTION

2 Background

2.1 Purpose

GasNet has lodged with the Regulator the draft GasNet Access Arrangement and draft GasNet AA Information in relation to the PTS to apply in the Third Access Arrangement Period commencing on 1 January 2008.

The purpose of this Submission is to provide a detailed explanation of the content of and principles underlying the proposed GasNet Access Arrangement and GasNet AA Information.

Generally, where GasNet's proposals or underlying assumptions do not differ significantly from the Second Access Arrangement, GasNet relies on the previous explanations provided and approval given in respect of the Second Access Arrangement.

2.2 The Market Carriage System

2.2.1 Background

GasNet and VENCorp operate under a Market Carriage system, which applies only in Victoria and, currently, only to the PTS. GasNet's submissions in respect of the Second Access Arrangement and VENCorp's previous Access Arrangement documents provide further detail on the existing Market Carriage regime and the significant implications of that regime for GasNet's proposed Access Arrangement.

In particular, the pay-as-you-go tariff system means that GasNet is subject to significant gas demand volume risk. GasNet's revenues are extremely sensitive to circumstances outside GasNet's control, such as weather patterns and expansions and contractions in the economy.

These factors contributed to a significant aggregate revenue shortfall anticipated to be $23.8 million during the Second Access Arrangement Period.

2.2.2 Proposed review of Market Carriage regime

On 11 July 2006, the Victorian Department of Infrastructure commenced a review of VENCorp to assess and evaluate the functions currently performed by VENCorp, and to determine whether any other functions should be vested. Subsequently, the final report of the VENCorp review ("**Final Report**") was released in November 2006 and provided to the Minister for Energy and Resources for consideration.

In response to the Final Report, GasNet understands that the Department is proposing amendments to the existing Victorian legislative framework, which may include removal of the obligation for VENCorp to submit an Access Arrangement. While no timetable has been set, GasNet understands the legislation is proposed to be introduced in the Spring Session 2007 (the Regulator has approved a revisions submissions date of 30 November 2007 for VENCorp as a result).

If passed, these proposals will have a significant and material impact on the existing legislative framework. In particular, under the existing arrangements GasNet has submitted its Access Arrangements on the basis that there are two Service Providers (as defined in the Code) with respect to the PTS:

(a) GasNet, being the owner of the PTS and responsible for the maintenance of the PTS; and

(b) VENCorp, being the operator of the PTS under the Market Carriage regime established by the MSO Rules,

and GasNet's Access Arrangement has always been read in conjunction with the VENCorp Access Arrangement.

In the event the proposed changes are passed, they will impact on the nature of GasNet's obligations under the Code and, consequently, on the appropriateness of the draft Access Arrangement proposed by GasNet for the Third Access Arrangement Period. They will also clearly impact on the nature of the existing arrangements between GasNet and VENCorp, and the existing arrangements with Users of the PTS.

Given the anticipated changes are still in their infancy, there is still a great deal of uncertainty as to the exact nature and timing of the changes and the likely impact of the changes on the draft Access Arrangement.

Accordingly, GasNet:

(a) submits the draft Access Arrangement on the basis that the status quo remains; and

(b) reserves its right to withdraw and resubmit on any impacted elements of its draft Access Arrangement in the event that the anticipated changes are made to the existing role of VENCorp in the Victorian gas industry.

To do otherwise (that is, to try to pre-empt or predict the proposed amendments) would be premature and inconsistent with GasNet's current legal obligations. In any event, it is likely that the majority of GasNet's draft Access Arrangement (and this supporting Submission) would remain the same under the anticipated proposals. That is, effectively, the economic analysis and cost structures would not differ significantly (perhaps with the exception of additional forecast operating costs for additional operational arrangements). The key changes are likely to be around the non-tariff terms and conditions of the Access Arrangement.

2.3 National energy market reforms

2.3.1 Background

In addition to the proposed changes to the Victorian regulatory regime, significant changes are underway in relation to the regulation of the national energy market.

As part of these arrangements, responsibility for the economic regulation of pipelines will be transferred from the Commission to the AER. In addition, a new governance framework will be implemented through a new South Australian Act called the *National Gas (South Australia) Act 2006*. This Act will contain a schedule called the National Gas Law ("**NGL**"). The NGL will be supplemented by national gas rules and a limited number of regulations dealing with minor matters and the prescription of civil penalties. It is intended this new framework will take the place of the current *Gas Pipelines Access (South Australia) Act 1997* and the Code.

2.3.2 Transitional issues

The latest timetable issued by the MCE indicates that the new regulatory framework as it affects the national gas industry will not be introduced until 1 July 2007 at the earliest. Accordingly, as at the date of this Submission, the new regime will not be in force. However, it is possible that the new regime will be in place at the time the final decision is issued.

The MCE has indicated that transitional provisions will be included in the new NGL so as to allow for the continuation of current processes for determinations by regulators. This is consistent with the approach taken to the transitional arrangements for electricity. These provided that where the Commission had taken action to make a draft determination, any final determination by the AER must be made in accordance with the provisions that existed before the commencement of the new electricity laws.

Accordingly, GasNet has prepared this Submission on the basis that its proposed Access Arrangement will be determined under the provisions of the Code, and not under the new NGL.

To the extent that the new NGL does not allow GasNet's proposed Access Arrangement to be determined under the existing Code, GasNet reserves its right to amend this Submission and its proposed Access Arrangement and AA Information.

3 GasNet System

3.1 Background

GasNet (together with its predecessor entities) has a thirty-seven year history in the gas transmission business. GasNet was created from the disaggregation of the Gas and Fuel Corporation of Victoria, the former Victorian state owned gas utility, and was listed on the Australian Stock Exchange in December 2001 as part of the GasNet Group. As of late 2006, GasNet became a wholly owned subsidiary of the APA Group.

GasNet is the owner of the PTS, which is the primary transmission system for the delivery of gas throughout Victoria. GasNet's subsidiary, GasNet (NSW), is the owner of that portion of the PTS located in New South Wales. However, GasNet NSW leases those assets to GasNet under an operating lease arrangement.

As a result of these arrangements, GasNet makes this application as:

(a) owner of the PTS (other than that portion of the Interconnect Pipeline located in New South Wales); and

(b) the lessee of the portion of the Interconnect Pipeline located in New South Wales.

GasNet (NSW) makes this application in its capacity as owner of that portion of the Interconnect Pipeline situated in New South Wales. For convenience, GasNet (NSW) and GasNet (which together own the entire PTS) will be collectively referred to as "GasNet".

3.2 Description of GasNet System

Although GasNet has previously submitted that the PTS should be referred to as the "GasNet System", for consistency between VENcorp and GasNet, GasNet has agreed to use the term PTS in the draft Access Arrangement.

The PTS comprises roughly 1,933 km of high pressure gas transmission pipelines, which serve a total consumption base of approximately 1.4 million residential consumers and approximately 45,000 industrial and commercial users throughout Victoria. A map of the PTS is included in Schedule 1.

The PTS has five main injection zones:

(a) Longford, comprising the injection points at:

  (i) the site of the ESSO/BHP Billiton processing facility; and

  (ii) VicHub (the interconnection with the Eastern Gas Pipeline);

(b) Culcairn, the NSW interconnection with the Moomba-Sydney Pipeline System;

(c) Port Campbell, comprising the:

  (iii) injection point for WUGS and local fields; and

(iv) interconnection with the SEA Gas Pipeline and Minerva processing plant;

(d) Dandenong, the site of the LNG facility; and

(e) Pakenham, the Injection point for gas sourced from the Yolla gas field.

The PTS is supplemented by a LNG storage facility which provides peak shaving and security of supply services for the PTS. The LNG storage facility is not part of the Covered Pipeline.

The PTS initially comprised two separate transmission pipelines, the principal transmission system and the western transmission system, and a separate access arrangement applied to each pipeline. However, as a result of the construction of the SWP, the PTS was physically linked to the WTS. As part of the Second Access Arrangement, the Commission agreed to a merger of the PTS Access Arrangement with the WTS Access Arrangement. The merged system became known as the GasNet System and is now called the PTS.

The PTS is more particularly described by reference to the Service Envelope Agreement. However, for the purposes of this Access Arrangement, it excludes any extensions or expansions that GasNet elects not to be covered by the Access Arrangement.[1]

GasNet WA, a member of the GasNet Group, also owns and operates a 450 km pipeline from Port Hedland to the Telfer and Nifty mines in Western Australia. Unlike the PTS, the Telfer Pipeline is an unregulated pipeline and does not fall under the Code.

3.3 Service Envelope Agreement

3.3.1 Function

GasNet and VENCorp are parties to the Service Envelope Agreement. Under the terms of this agreement:

(a) GasNet agrees to:

(i) make available the entire PTS to VENCorp; and

(ii) provide a range of supporting Services to VENCorp; and

(b) VENCorp agrees to:

(i) operate the PTS in accordance with the MSO Rules; and

(ii) have the direct legal relationship with Users regarding a range of issues, including payment of charges for transmission Services.

[1] See clause 5.1 of the Access Arrangement.

As a result of the Service Envelope Agreement, VENCorp has operational control of the entire PTS and will be able to determine the manner in which Users are able to obtain Services provided by means of the PTS.

3.3.2 Duration

The Service Envelope Agreement commenced on 15 March 1999 and was due to expire on 31 December 2007.

However, GasNet and VENCorp have agreed to extend the term of the Service Envelope Agreement for another 5 years, and the Service Envelope Agreement will now operate until 31 December 2012.

PART B - TARIFF ISSUES

4 Reference Tariff Principles

4.1 Summary of GasNet's Proposal

GasNet proposes to retain the Building Block Methodology for Total Revenue determination. This is the methodology used for the current GasNet Access Arrangement.

Each of the elements comprising the Total Revenue is discussed below. For each of these elements, GasNet has sought to apply the Reference Tariff Principles set out in section 8 of the Code in a way that recognises the fundamental importance of the criteria set out in section 2.24 of the Code.

In particular, GasNet has sought to recognise the requirement that the Regulator must take into account GasNet's legitimate business interests and investment, the public interest and the interests of Users and Prospective Users.

GasNet also proposes to apply a combination of a Reference Tariff Control Formula Approach and a Trigger Event Adjustment Approach to varying the Reference Tariffs during the Third Access Arrangement Period.

4.2 Code Requirements

4.2.1 Access Arrangements

Section 3.4 of the Code requires the Regulator to be satisfied that the Access Arrangement and any Reference Tariff included in the Access Arrangement comply with the Reference Tariff principles described in section 8 of the Code.

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. The Reference Tariff Policy must, in the regulator's opinion, comply with the Reference Tariff objectives set out in section 8 of the Code.

4.2.2 Requirements of section 8 of the Code

The Reference Tariff Policy and all the Reference Tariffs should be designed to achieve the objectives set out in section 8.1 of the Code. To the extent that these objectives may conflict in their application, the Regulator may determine how they can best be reconciled, or which of them should prevail.

Section 8.2 of the Code then provides that, in determining whether to approve the Reference Tariffs and the Reference Tariff Policy, the Regulator must be satisfied that:

(a) the revenue to be generated from sales (or forecast sales) of all Services over the Access Arrangement Period (i.e. the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in section 8 of the Code;

(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 is calculated consistently with the principles contained in section 8 of the Code;

(c) a Reference Tariff is designed so that the portion of Total Revenue to be recovered from a Reference Service is recovered from Users consistently with the principles contained in section 8 of the Code;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the relevant regulator considers appropriate and that such Incentive Mechanisms are consistent with the principles contained in section 8 of the Code; and

(e) any forecasts required to set the Reference Tariffs represent best estimates arrived at on a reasonable basis.

4.2.3 Overarching principles

In applying the principles in section 8 of the Code (including the principles in sections 8.1 and 8.2), the Regulator must apply the principles in a way that recognises the paramount importance of the criteria in section 2.24 of the Code. In relation to Reference Tariffs, the most significant of these criteria that the Regulator must take into account are:

(a) GasNet's legitimate business interests and investment in the PTS;

(b) the public interest; and

(c) the interests of Users and Prospective Users.

A practical implication of this is that it is in the interests of Users, GasNet and the public for the Regulator to take into account the long run benefits of encouraging investment in infrastructure, even when this may be perceived to conflict with the short run benefits of, for example, lower tariffs.

GasNet refers the Regulator to GasNet's substantial discussion on the benefits of infrastructure as part of its submissions on the Second Access Arrangement.

4.3 Reference Tariff Methods

For the purposes of section 8.4 of the Code, GasNet proposes to retain the Building Block Methodology for calculating Total Revenue. This is the methodology used in the current GasNet Access Arrangement.

Under the Building Block Methodology, the revenue to be generated from the sales of all Services over the Third Access Arrangement Period is, subject to the Code, equal to the cost (or forecast cost) of providing all Services. This is calculated on the basis of:

(a) a return on the value of the capital assets that form the Covered Pipeline or are otherwise used to provide Services (i.e. Rate of Return);

(b) depreciation of the Capital Base (i.e. Depreciation); and

(c) the operating, maintenance and other non-capital costs incurred in providing all Services provided by means of the Covered Pipeline (i.e. Non Capital Costs).

Each of these elements is discussed in the Submission below.

4.4 Reference Tariff Method

For the purposes of section 8.3 of the Code, GasNet proposes to apply a Reference Tariff Control Formula Approach to varying Reference Tariffs during the Third Access Arrangement Period.

Under this approach, an initial set of Reference Tariffs may vary over the Access Arrangement Period in accordance with a specified formula or process.

This is discussed further in section 11 of this Submission.

5 Establishing the Capital Base

5.1 Summary of GasNet's Proposals

5.1.1 Code requirements

Consistent with section 8.9 of the Code, GasNet has calculated the Capital Base for the commencement of the Third Access Arrangement Period by rolling forward the Capital Base from the Second Access Arrangement Period and making adjustments for New Facilities Investment, Depreciation, inflation and Redundant Capital.

5.1.2 Rolling forward the Capital Base

The Capital Base approved by the Commission in its 2002 Final Decision for the commencement of the Second Access Arrangement Period was $494.1 million. GasNet has updated this figure to take account of the actual capital expenditure for 2002 and the actual inflation rate for that period.

5.1.3 New Facilities Investment

In 2002, the Regulator approved various items of forecast capital expenditure for the Second Access Arrangement Period totalling $47.72 million.[2]

To date, GasNet has commenced all of the approved projects and expects to complete most of them by the end of 2007.

In addition, GasNet has completed (or is in the process of completing) a number of projects which were not included in the forecast capital expenditure for the Second Access Arrangement Period.

The actual cost of projects commissioned by GasNet in the Second Access Arrangement Period up to the end of 2006 was $24.7 million. GasNet expects to commission additional projects with a cost of $45.4 million during the period 1 January 2007 to 31 December 2007. A significant proportion of the capital expenditure on projects to be commissioned in 2007 has already been incurred, but as capital expenditure is recognised on an "as commissioned basis" these costs are shown as 2007 costs. The total capital expenditure for the Second Access Arrangement Period is expected to be $70.11 million.

5.1.4 Depreciation

The Capital Base has been depreciated by GasNet in accordance with the Depreciation Schedule approved by the Commission as part of its 2002 Final Decision, without any adjustment to reflect differences between forecast and actual capital expenditure. The Depreciation Schedule has been adjusted to reflect differences between forecast and actual inflation.

2 Note the forecast capital expenditure approved by the Commission was $46.84 (nominal $). GasNet has updated this figure to account for actual inflation during the regulatory period.

5.1.5 *Redundant Capital and Disposals*

There are no wholly or partially redundant assets for the Second Access Arrangement Period and there have been no disposals of regulated assets.

5.1.6 *Corporate restructuring costs*

GasNet has included the corporate restructuring costs incurred in 2006 in the Capital Base.

5.1.7 *Inflation*

As required by section 8.9 of the Code, GasNet has adjusted the Capital Base for inflation. Consistent with the real Rate of Return tariff methodology employed by GasNet, the Capital Base has been escalated each year in line with actual inflation.

For 2007, GasNet has used a forecast figure of 3.09%. GasNet proposes to update this figure after the draft decision is issued to reflect the actual inflation rate for the first half of 2007. For the remaining half of 2007, GasNet proposes to use the same annual inflation figure as approved for the Third Access Arrangement Period.

5.1.8 *Summary of Capital Base*

A summary of each element of the rolled forward Capital Base is set out in Table 5.1 below.

Table 5.1: Summary of Capital Base (Nominal $m)

Year ending 31 December	**2003**	**2004**	**2005**	**2006**	**2007**
Opening Capital Base	496.2	488.0	479.7	473.9	485.7
Inflation on Opening Capital Base	11.9	12.6	13.4	15.1	15.0
Depreciation Allowance(1)	-20.6	-21.6	-22.8	-23.9	-24.4
Capital Expenditure(1)	0.5	0.7	3.6	20.7	48.1
Disposals/Redundancies(1)	0.0	0.0	0.0	0.0	0.0
Closing Capital Base	**488.0**	**479.7**	**473.9**	**485.7**	**524.36**

(1) Depreciation allowance, Capital expenditure and Disposals are in end of year dollars

Each of these elements is discussed in greater detail in sections 5.3 to 5.11 (inclusive) below.

5.2 Code requirements

The Code sets out a number of general principles in relation to establishing the Capital Base as at 1 January 2008. In addition to the general principles and factors set out in section 8.1 and 8.2 of the Code, sections 8.9 and 8.15 to 8.29 describe principles to be applied in adjusting the value of the Capital Base over time.

In particular, section 8.9 of the Code outlines the way in which the Capital Base under an Access Arrangement may be rolled forward into the following Access Arrangement Period. For the Building Block Methodology, it provides that the Capital Base at the start of a new Access Arrangement Period is calculated by reference to:

(a) the Capital Base at the start of the immediately preceding Access Arrangement Period; plus

(b) subject to sections 8.16(b) and section 8.20 to 8.22, the New Facilities Investment or Recoverable Portion (whichever is relevant) in the immediately preceding Access Arrangement Period; less

(c) Depreciation for the immediately preceding Access Arrangement Period; less

(e) Redundant Capital identified prior to the commencement of the Access Arrangement Period.

5.3 Capital Base at commencement of Second Access Arrangement Period

The starting point for the calculation of the rolled forward Capital Base is the Capital Base at the commencement of the previous Access Arrangement Period.

The Capital Base at the commencement of the Second Access Arrangement Period as approved by the Commission in its 2002 Final Decision was $494.1 million.

This included an allowance for capital expenditure for 2002 of $661,802. The actual amount of capital expenditure incurred in that period was $307,498. GasNet has updated the opening Capital Base to reflect the actual amount of capital expenditure incurred during 2002.

The Capital Base approved by the commission also included a forecast CPI of 0.54% for the period from 30 September 2002 to 31 December 2002. However, the actual inflation rate for that period was 0.72%. GasNet has updated the opening Capital Base to reflect the actual inflation rate during that period.

5.4 Redundant Capital

Clause 4.6 of the Second Access Arrangement provides that the Commission may review and, if necessary, adjust the Capital Base (at the start of the Third Access Arrangement Period) to take account of wholly or partially redundant assets.

GasNet has not identified any assets which are wholly or partially redundant assets for the Second Access Arrangement Period.

There have been no disposals of regulated assets other than a small parcel of land valued at $20,000.

5.5 New Facilities Investment – summary of forecast vs actual

5.5.1 Code requirements

One of the items to be considered in the determination of the Capital Base at the commencement of the Third Access Arrangement Period is the New Facilities Investment or Recoverable Portion (whichever is relevant) in the current Access Arrangement Period (adjusted as relevant as a consequence of section 8.22 of the Code to allow for differences between the actual and forecast New Facilities Investment).

Section 8.22 of the Code provides that either the Reference Tariff Policy should describe or the Relevant Regulator shall determine how the Capital Base at the commencement of an Access Arrangement Period will be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in section 8.1).

Section 8.22 sets out a procedure for dealing with how New Facilities Investment is to be determined for the purposes of section 8.9 of the Code. GasNet submits that this section is intended to deal with under or over-spends on forecast capital expenditure or where capital was expended on a project which is similar, but not identical to, the ones forecast.

5.5.2 Summary of New Facilities Investment

In its 2002 Final Decision, the Commission approved Reference Tariffs which incorporated forecast capital expenditure of $47.72 million. This forecast capital expenditure was reasonably expected to pass the requirements for New Facilities Investment when the investment was forecast to occur. Table 5.2 sets out the amount approved by the Commission for each project.

Table 5.2: Approved forecast capital expenditure

Forecast (Nominal $m)						
Projects	**2003**	**2004**	**2005**	**2006**	**2007**	**TOTAL**
Gooding Compressor Refurbishment			6.52	8.19	8.05	**22.77**
Lurgi Pipeline Refurbishment	2.05	2.11	1.56			**5.72**
City Gate Upgrades and Heaters		3.48	2.54	3.34		**9.36**
Wollert Compressor Station Automation		1.16	1.73			**2.89**
Gas Chromatographs	0.92					**0.92**
Other Maintenance Capital Expenditure	1.90	1.75	0.61	0.64	1.17	**6.06**
Total	**4.87**	**8.50**	**12.96**	**12.17**	**9.22**	**47.72**

The forecast capital projects approved by the Commission have proceeded largely as originally planned, although some of the projects will be completed later than expected.

Table 5.3 below sets out the actual amount of capital expenditure incurred in respect of these projects to date during the Second Access Arrangement Period, together with a forecast of expenditure for 2007. Note that these costs are reported on an “as-commissioned” basis. This means that the total cost of the project is only reported when the project is commissioned, despite the fact that costs may have been incurred in 2006 or earlier.

Table 5.3: Actual capital expenditure on approved projects

Actual (Nominal $m)						
Projects	**2003**	**2004**	**2005**	**2006**	**2007**	**TOTAL**
Gooding Compressor Refurbishment					16.03	**16.03**
Lurgi Pipeline Refurbishment				2.82		**2.82**
City Gate Upgrades and Heaters					5.38	**5.38**
Wollert Compressor Station Automation					2.76	**2.76**
Gas Chromatographs	0.27	0.19				**0.46**
Other Maintenance Capital Expenditure	0.21	0.30	1.09	0.70	2.38	**4.70**
Total	**0.48**	**0.50**	**1.09**	**3.52**	**26.57**	**32.16**

There have been other projects undertaken by GasNet during the Second Access Arrangement Period which were not forecast at the commencement of that period. The major items of non-forecast capital expenditure are set out below. Note that these costs do not include projects planned for commissioning in 2008 or later. In particular, they do not include any expenditures on the Brooklyn Lara (Corio) pipeline.

Table 5.4: Non forecast capital expenditure

Non forecast capital expenditure (Nominal $m)						
Projects	**2003**	**2004**	**2005**	**2006**	**2007**	**TOTAL**
Brooklyn Compressor Redevelopment				3.00	14.46	**17.46**
South Melbourne Cut In				2.98		**2.98**
Wollert Compressor station (miscellaneous)		0.17	0.83		1.15	**2.15**
Pig traps					0.72	**0.72**
Safety and Security					0.79	**0.79**
Iona Cooler Upgrade					0.70	**0.70**
Regulators Work					0.42	**0.42**
Maximo			1.37			**1.37**
Corporate Restructuring				8.84		**8.84**
Total	**0**	**0.17**	**2.20**	**14.82**	**18.23**	**35.42**

The actual capital expenditure in the Second Access Arrangement Period for projects commissioned up to the end of 2006 was $24.7 million. GasNet expects to report additional capital expenditure of $45.4 million on projects to be commissioned during the period 1 January 2007 to 31 December 2007. A significant proportion of the forecast capital expenditure for 2007 has already been incurred (approximately $20 million), but as capital expenditure is currently recognised on an "as commissioned basis" these costs are reported in 2007. Note that these totals include interest during construction, which is not included in the figures reported in Tables 5.3 to 5.5.

This gives an aggregate amount of capital expenditure for the Second Access Arrangement Period of $70.11 million, against a forecast amount of $47.72 million (see Table 5.5 below). GasNet proposes to include all of this capital expenditure in its rolled-forward Capital Base.

Table 5.5: Total capital expenditure against forecast (Nominal $m)

	2003	2004	2005	2006	2007	TOTAL
Total approved capital expenditure	4.87	8.50	12.96	12.17	9.22	**47.72**
Total actual capital expenditure	0.48	0.66	3.30	18.34	44.80	**67.58**
Total overspend	-4.39	-7.84	-9.66	6.17	35.58	**19.86**

5.5.3 Interest during Construction

As mentioned above, GasNet reports project capital expenditure in the year that the asset is commissioned, despite the fact that the construction costs may be distributed over more than one year. Consequently, GasNet incurs additional costs to finance the cash outflows over the construction period.

On this basis, GasNet considers it appropriate to include an allowance for interest during construction on the total reported costs.

The figures in Tables 5.3 to 5.5 and the text in sections 5.7 and 5.8 do not incorporate an allowance for interest during construction, which is included in the Capital Base. However, the summary in Table 5.1 and the figures in the text in sections 5.1 and 5.5 do incorporate interest during construction.

5.6 Code requirements for New Facilities Investment and application of requirements

Section 8.16(a) of the Code provides that the Capital Base may be increased by the amount of actual New Facilities Investment in the immediately preceding Access Arrangement Period provided that:

(a) the amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services ("**Prudency Test**"); and

(b) one of the following conditions is satisfied:

  (i) the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment ("**Economic Feasibility Test**");

  (ii) the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of higher Reference Tariffs for all Users ("**System-Wide Benefits Test**"); or

  (iii) the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services ("**System Integrity Test**").

The System-Wide Benefits Test and the System Integrity Test are described further in section 7.4 below.

GasNet submits that all capital expenditure incurred in the Second Access Arrangement Period was of a maintenance nature and did not increase or augment the capacity of the PTS. Accordingly, with respect to the second limb of the test (section 8.16(a)(ii)), GasNet submits that the capital expenditure satisfies the System Integrity Test.

With respect to the first limb of the test (section 8.16(a)(i)), GasNet submits that all capital expenditure spent or anticipated to be spent by the end of 2007 is efficient and prudently incurred. In particular (and where justified by the size of the project), tenders were sought for works under each project in order to find the most efficient and lowest final cost solution. A detailed description and justification of each main project is provided in the following sections.

5.7 Actual New Facilities Investment (projects forecast in 2002)

5.7.1 Gooding compressor refurbishment

The Gooding compressor station refurbishment commenced in 2005 and is expected to be completed during 2007.

The compressor station, which was constructed in 1976, was showing signs of wear and erosion consistent with having been in service for nearly 30 years. In addition, the compressor staging no longer matched the ideal operating point, which has moved with changes in flows and demand.

The work associated with refurbishment has been done in two stages, with the first stage completed in 2006 and the second stage expected to be completed in 2007.

Stage 1 involved:

(a) installing a new fuel gas heater system;

(b) replacing the back-up generator and other electrical work;

(c) replacing the compressor house vent fans, which had been badly corroded; and

(d) upgrading the safety and process control system and communication network to ensure compliance with AS61508 (functional safety of electrical/electronic/programmable electronic safety-related systems) design and safety standards.

Stage 2 will involve:

(a) replacing unit exhausts which are showing cracking and emit excessive noise (which gives rise to issues under Environmental Protection Authority noise requirements);

(b) replacing the compressor units using modern dry seals technology, and restaging to the optimal operating point;

(c) replacing the engine filtered air supply assemblies; and

(d) installing failsafe valves and a gas recycle circuit to improve station control.

GasNet has determined that the compressor engines do not need replacement and can operate efficiently with ongoing maintenance and regular overhauls.

The amount approved by the Commission for the works was $22.27 million. The actual amount GasNet expects to incur for this project is $16.03 million.

5.7.2 *Lurgi pipeline refurbishment*

The Lurgi pipeline was built in 1956 and is the oldest gas transmission pipeline in Australia. GasNet had been unable to undertake any internal investigations of the pipeline to identify evidence of corrosion as the line valves were not designed to enable the passage of a pig. The upgrades to the Lurgi pipeline to facilitate pigging were started in 2003 and were completed in 2006.

The amount the Commission approved for these works as part of the Second Access Arrangement was $5.72 million. The actual amount incurred by GasNet in relation to these works was $2.82 million.

The actual amount expended on the works is significantly less than originally forecast. The cost savings represent efficiencies identified during the progress of the works.

5.7.3 *City gate upgrades and heaters*

As part of its Second Access Arrangement, GasNet sought approval for forecast capital expenditure to upgrade the Dandenong, Wollert and Morwell city gates and the Tyers pressure limiter. GasNet also sought approval for the installation of gas heaters at the Dandenong, Wollert and Tyers regulator stations.

The upgrades to the city gates were required because most of the regulators and associated controls were over 30 years old and experienced frequent failures.

The installation of the gas heaters at the regulator stations was required to mitigate the risk of gas cooling below the standard specified in the Gas Safety Regulations 1999 and the VENCorp Gas Quality Guidelines, and to mitigate associated negative effects such as condensate drop out, hydrate formation and ice forming on control facilities.

Most of the work on the city gate regulators and heaters is expected to be completed in 2007. However:

(a) the Dandenong city gate upgrade and heater installation is not expected to be completed until 2008. This is because the valves required for the capital expenditure are in short supply due to high world demand and as a consequence there is a 12 month delay for delivery; and

(b) the gas heater at the Tyers regulator station is no longer required. The need for this heater was driven by the expectation that a large customer would connect directly to the transmission system between Morwell and Tyers. As this customer never eventuated, there is no longer a requirement for a heater.

The amount approved by the Commission for the city gate upgrades and heaters was $9.36 million. The actual amount GasNet expects to spend on commissioned projects to the end of 2007 is $5.38 million, with a further $6.09 million for the Dandenong city gate and heater work now delayed to 2008. This represents an increase in real terms of about 18 per cent over what was originally estimated.

The marginal increase in costs is related to general increases in material costs as observed across the gas industry, and to changes in design arising from more detailed engineering evaluations. In particular, further analysis indicated that a larger regulator was required at Morwell city gate, and a larger heater will be required at the Dandenong city gate.

5.7.4 Wollert compressor station automation

The Wollert compressor station automation is expected to be completed in 2007. The works are required to enable reliable remote operation of the system by VENCorp. In addition, the poor reliability of the existing control system has meant that the station requires manning for start up which is not viable over the long term. Spare parts and product services were also becoming increasingly difficult to source leading to unacceptable repair delays.

The amount approved by the Commission for these works was $2.89 million. The actual amount anticipated by GasNet in respect of the works is $2.76 million.

The costs incurred in relation to the automation of the compressor station are consistent with the forecast and with similar automation work undertaken by GasNet in the First Access Arrangement Period.

5.7.5 Gas chromatographs

GasNet has installed three gas chromatographs at Alansford, Brooklyn and Corio over the period 2003 to 2004. These chromatographs were installed at the request of VENCorp and were required to cater for the more complex flows possible across the PTS arising from various new supply points. The heating value of the gas flowing at certain points needed to be calculated with greater accuracy to ensure that all gas supplied across the system met the requirements of the MSO Rules.

The amount approved by the Commission for these works was $0.92 million. The actual amount incurred by GasNet in respect of the works was $0.46 million.

The actual cost of the works was significantly less that the approved forecast. The main cost savings were in labour because GasNet used internal labour instead of outsourcing this work, and in some of the materials.

5.7.6 *Other maintenance capital expenditure*

GasNet has undertaken numerous small maintenance projects over the Second Access Arrangement Period, including:

(a) information technology upgrades (both software and hardware);

(b) upgrades to various assets such as cathodic protection units, office buildings, station instruments, electronic systems and heat exchangers; and

(c) the acquisition of field and workshop equipment.

The amount approved by the Commission for maintenance capital expenditure was $6.06 million. The actual amount incurred by GasNet is expected to be $4.70 million.

5.8 Actual New Facilities Investment (projects not forecast in 2002)

5.8.1 *Brooklyn compressor station redevelopment*

GasNet has commenced a major redevelopment of the Brooklyn compressor station to replace aging and outdated equipment with new facilities. This work is being undertaken in stages, with one unit replaced in 2006 and a second unit to be replaced in 2007. The remainder of the station will be converted and upgraded in 2008 and 2009 as part of GasNet's proposed New Facilities Investment for the Third Access Arrangement Period, which is discussed in detail in sections 7.6.2 and 7.6.3 below.

A detailed description of the scope and rationale for the work is given in the GasNet Compressor Strategy which is attached to this Submission.

The station was originally established in 1972. In 1979,[3] four Saturn units were installed, and a further two larger Centaur units and two additional Saturn units[4] were installed in 1982.

The site is located in an urban area and has now become extremely congested due to the additional compressor units, complex inlet and outlet pipework and multiple regulator runs. This leaves limited opportunities to expand the facilities within the existing confines of the site. The equipment is also old and outdated, and is due for replacement. As documented in GasNet's Compressor Strategy, there have been multiple failures at the compressor station.

As part of GasNet's overall review of the scope of refurbishment works required at the Brooklyn compressor station, a key driver was a requirement imposed by Energy Safe Victoria that all gas companies take appropriate steps to prevent the entry of liquids into gas transmission and distribution networks. Energy Safe Victoria noted in a letter to GasNet that additional short and longer term capital investment may be required including, where technically feasible, use of dry seal compressors.

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[3] Two units which are not part of the Capital Base were removed in winter 1998 as a result of the ESSO emergency.

[4] Although only 4 of the Saturn units are included in the Capital Base.

This resulted in GasNet introducing a program to convert from wet seals to dry seals at all of its compressor stations. The switchover has been prioritised on the basis of opportunity and importance, and the need to schedule the workload over a reasonable time. The Gooding compressor station was the first station to have the wet seals replaced, as this was the oldest station and GasNet was already in the process of replacing the compressors as part of work planned for the current Access Arrangement Period. The Brooklyn compressor station was selected next due to the poor condition of the station, aging and outdated equipment and safety concerns. The Wollert station will be converted by 2009 as part of a broader capacity upgrade at that site.

One Centaur compressor at Brooklyn (unit 11) was converted to dry seals in 2006 at a cost of approximately $3 million. However, the same engineering solution could not be applied to the other Centaur compressor at the site (unit 10) because of its obsolete design. Accordingly, it was determined that unit 10 should to be replaced with a new engine and compressor assembly (unit 12). Unit 10 will be kept temporarily as a redundant unit for those occasions when two Centaurs are required to meet the service. These works along with works to replace the vent stacks will be completed in 2007 at an expected cost of $17.46 million.

5.8.2 *South Melbourne cut in*

In 2006 GasNet completed the South Melbourne cut in project which involved the installation of two pig traps on the pipeline that connects the Dandenong to West Melbourne pipeline with the South Melbourne to Brooklyn pipeline. The cost of these works was $2.98 million.

The pig traps were required so that intelligent pigging could be performed on the pipeline and an assessment made of its integrity and quality. Pigging on this pipeline had been scheduled for this Access Arrangement Period, but an allowance for the installation of pig traps had not been made. The results of the pigging allow GasNet to determine safe maximum operating pressures on the pipeline which, from a safety perspective, is particularly important in densely populated urban areas.

The cost of this project takes into account the higher costs associated with undertaking this sort of work in a densely populated area.

5.8.3 *Wollert compressor station - miscellaneous works*

In addition to the compressor station automation which was part of the approved capital expenditure for the Second Access Arrangement Period (see section 5.7.4 above), GasNet has also undertaking additional work at the Wollert compressor station. This work includes an engine overhaul in 2004, replacement of the unit coolers and water tanks with a fin-fan cooler in 2005, and a range of electrical works, expected to be completed in 2007.

The electrical works includes:

(a) the replacement of the existing motor control system which has become obsolete;

(b) installation of a new back-up generator to replace the existing obsolete power supply;

(c) replacement of the existing 30 year old lighting and fittings; and

(d) upgrade of the existing 22kv power supply.

The total costs of these projects is expected to be $2.15 million.

5.8.4 Pig traps (Bunyip to Pakenham)

GasNet is installing pig traps on the Bunyip to Pakenham line which will be complete in 2007. This work is required to facilitate pigging of the pipeline (in accordance with licence requirements and AS 2885) which is scheduled for 2008. The expected cost of the works is $0.72 million.

The costs associated with these works are consistent with those for the Lurgi pipeline.

5.8.5 Iona cooler upgrade

GasNet intends to install a new compressor station cooler at the Iona compressor station by winter 2007. The expected cost of the project is $0.70 million.

In the VENCorp APR, VENCorp identified that the pressures at Portland and Hamilton could fall below the required minimum connection pressures without additional power at Iona. The Iona cooler upgrade will assist to address this potential constraint.

5.8.6 Safety and security

In 2003, the Terrorism Act came into effect in Victoria. The Terrorism Act provides for the involvement of the operators of essential services in planning for the protection of essential services from terrorist attacks. The Governor in Council has declared GasNet’s transmission network to be an “essential service” for the purposes of the Terrorism Act.

Under the Terrorism Act, GasNet is required to prepare a risk management plan, conduct an annual audit of the plan and update it for any deficiencies identified in the audit.

GasNet conducted an audit of its risk management plan in 2006 and identified a range of capital and non-capital expenditure that will be required to meet the outcomes of the audit. Most of the capital expenditure relates to security upgrades, including remote monitoring of GasNet’s assets.

GasNet has identified Dandenong and Pakenham as priority sites to commence the security upgrade in 2007. These sites were selected to operate as pilot sites based on site risk. The anticipated cost of these works is $0.48 million.

The remaining sites identified by GasNet’s consultant will be upgraded during the Third Access Arrangement Period and are identified in section 7.6 of this Submission.

In accordance with the requirements of the *Victorian Safety Act*, GasNet is undertaking a hazardous area review to enable the creation of site verification dossiers which identify all electrical equipment which is located within hazardous areas (areas with the potential for gas leaks).

GasNet expects to incur costs of approximately $0.79 million in relation to this project in 2007. These costs cover the creation of a dossier database, together with some rectification works which have already been identified during the production of the verification dossiers.

5.8.7 *Regulators*

GasNet is upgrading the back-up regulators at the Dandenong terminal station where the Lurgi pipeline connects to the metropolitan system. This is required because the existing facilities are near the end of their life. The work is scheduled for completion in 2007 at an estimated cost of $0.42 million.

5.8.8 *Maximo*

GasNet has implemented an asset management system which utilises the computer program Maximo. Maximo brings together asset design, safety procedures and other matters integral to the safe maintenance and operation of the GasNet assets into a common searchable database.

Maximo substantially enhances the ability of GasNet's engineers to work on the assets with a full history of maintenance activity and changes to the design and maintenance procedures for each asset, thereby enhancing GasNet's ability to ensure the safety and integrity of the Pipeline.

The total cost of Maximo for the regulated business is $1.37 million.

5.8.9 *Corporate restructuring costs*

During the Second Access Arrangement Period, GasNet incurred costs in excess of $10 million in relation to the eventual successful takeover by the APA Group in 2006. The cost to the regulated business was $8.84 million. This amount includes payments to legal advisers, evaluation experts and strategic consultants for strategic advice and a break fee. These costs are an inescapable component of the corporate restructuring which has been taking place in the gas industry in recent years. GasNet proposes to capitalise these costs and has therefore added them to the Capital Base.

GasNet submits that it is consistent with the requirements of the Code to include them in the Capital Base, on the basis that:

(a) the Victorian Government made a policy decision to privatise the PTS as it believed that private ownership would achieve the most efficient operation of the PTS;[5]

(b) a natural consequence of private ownership is subsequent merger and acquisition activity and the necessary costs involved in that activity;

[5] Gas Industry (Amendment) Bill, Second Reading speech, Legislative Council, 7 December 1999. See especially p369.

(c) corporate restructuring activity will result in efficiencies through economies of scale and scope; and

(d) these economies will eventually be passed on to users through lower tariffs.

For these reasons, GasNet submits that the restructuring costs associated with the most efficient form of ownership of the PTS are costs that were efficiently and prudently incurred.

5.9 Brooklyn Lara (Corio) Pipeline

GasNet commenced construction of the Brooklyn Lara (Corio) pipeline in 2006, but the project will not be completed until April 2008. Consistent with the "as commissioned" methodology applied by GasNet in respect of capital expenditure during the Second Access Arrangement Period, the 2006 and 2007 costs for the Brooklyn Lara (Corio) pipeline will be included in the forecast capital expenditure for the Third Access Arrangement Period.

5.10 Depreciation 2003-2007

5.10.1 Code requirements

Section 8.9 of the Code provides that, in determining the Capital Base at the commencement of each Access Arrangement Period, Depreciation for the immediately preceding Access Arrangement Period must be taken into account.

5.10.2 Depreciation methodology

GasNet applied the CCA framework and a real Rate of Return for establishing target revenues for the Second Access Arrangement Period. Under this framework, the Capital Base was notionally re-valued in line with inflation on an annual basis. A real straight line depreciation profile was adopted to determine the Depreciation Schedule for the Second Access Arrangement Period, except for the SWP which was levelised over the first 20 years.

5.10.3 GasNet's proposal

In establishing the Capital Base for the commencement of an Access Arrangement Period, section 8.9 of the Code requires the Capital Base at the commencement of the immediately preceding Access Arrangement Period to be written down by the Depreciation for the immediately preceding Access Arrangement Period.

The term Depreciation is defined as:

> *in any year and on any asset or group of assets, the amount calculated according to the Depreciation Schedule for that year for that asset or group of assets.*

The term *Depreciation Schedule* is defined as:

> *… the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff …*

Accordingly, GasNet has depreciated the Capital Base in accordance with the Depreciation Schedule approved by the Commission at part of the Second Access Arrangement with no adjustment to reflect any differences between forecast and actual capital expenditure. The Depreciation Schedule has been adjusted to reflect the actual inflation outcome.

5.11 Inflation 2003-2007

Consistent with the real rate of return tariff methodology applied by GasNet, the Capital Base has been escalated each year in line with inflation. The impact on the Capital Base is set out in the AA Information.

For 2007, GasNet has used a forecast figure of 3.09% (see section 6.6 below). GasNet proposes to update this figure after the draft decision is issued to reflect the actual inflation rate for the first half of 2007. For the remaining half of 2007, GasNet proposes to use the inflation figure applicable to the Third Access Arrangement Period.

6 Rate of Return

6.1 Summary of GasNet's Proposals

In determining the proposed Rate of Return, GasNet applies the well established WACC and CAPM methodologies employed by the Commission and other regulators.

For the reasons set out in section 6.3 below, in establishing the WACC parameters GasNet has followed regulatory precedent and proposes to use the parameters adopted in the Commission's most recent decisions on access arrangements for gas Transmission Pipelines ("**Commission parameters**"). These parameters are also consistent with the AER Compendium. The Commission parameters are to be considered as a package.

However, although GasNet has for the purposes of the Access Arrangement chosen to use the Commission parameters, it considers that those parameters are generally either below, or at the lower end of, the range of outcomes which satisfy the requirements of the Code.

6.2 Code requirements

Section 8.4(a) of the Code provides that, under a Building Block Methodology, the Total Revenue must include *a return (Rate of Return) on the value of the capital assets that form the Covered Pipeline (Capital Base).*

Section 8.30 of the Code provides that the Rate of Return should provide a return which is commensurate with:

(a) prevailing conditions in the market for funds (presumably including equity and debt); and

(b) the risk involved in delivering the Reference Service.

Section 8.31 of the Code suggests, as an example, using a weighted average of the return applicable to each source of funds (equity, debt and any other relevant sources of funds) and that such a return may be determined on the basis of a well accepted financial model, such as the CAPM.

Section 8.31 of the Code goes on to provide that in general the weighted average of the returns on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice (although it also provides that other approaches may be adopted where the relevant Regulator is satisfied to do so would be consistent with the objectives contained in section 8.1 of the Code).

6.3 Approaches to the Rate of Return

It is now well established that there are a range of feasible outcomes that would satisfy the requirements of the Code.[6] This is particularly true in relation to the WACC parameters.

[6] See, for example, *Re: Dr Ken Michael AM; ex parte EPIC Energy (WA) Nominees Pty Ltd Anor* [2002] WASCA 231 (23 August 2002); *GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6; ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006.

GasNet has always taken the view that:

(a) where a range of outcomes would satisfy the Code, values in the mid to upper end of the range should be adopted; and

(b) there are asymmetric consequences of regulatory error in setting the WACC.

This is supported by the expert advice provided to GasNet by Synergies.[7]

GasNet believes that the WACC parameters employed by the Commission for calculating the Rate of Return for gas transmission are either below, or at the lower end of, the range of outcomes which would satisfy the Code. Nevertheless, for the purposes of the draft Access Arrangement, GasNet proposes to adopt the WACC parameters which have been previously adopted by the Commission.

GasNet submits that there is no justification for the Regulator to move away from these parameters toward any parameters which would result in a lower WACC. In particular, GasNet supports the Commission's view that the Commission should take a cautious approach to moving away from these parameters given[8]:

(a) the substantial changes which are currently being made to the regulatory regime applicable to the gas industry; and

(b) the desire of policy makers to balance certainty and consistency with the need for flexibility.

GasNet also notes that its proposal to adopt the Commission parameters is to be considered as a "package". That is, if the Regulator does not agree to GasNet's use of any one of these parameters, GasNet reserves the right to submit revised values for each of the WACC parameters.

6.4 WACC parameters

GasNet has expressed its proposal in terms consistent with the CAPM model. The key parameters used to develop the WACC within the context of the CAPM model, together with GasNet's proposals, are set out in Table 6-1.

Table 6-1: WACC Parameters

WACC Parameter	GasNet Proposal
Real risk-free interest rate	2.68%*
Nominal risk-free interest rate[a]	5.85%*
Bond Maturity Period	10 years
Bond type	Commonwealth Bonds
Bond calculation period	40 days ending on a date to be

7 See Synergies Economic Consulting "Weighted Average Cost of Capital Review for GasNet Australia" March 2007 at Attachment F to this Submission.

8 See ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p87.

WACC Parameter	GasNet Proposal
	agreed *ex ante* with the Regulator
Forecast Inflation	3.09%*
Inflation selection period	10 years (consistent with bond maturity period)
Debt margin[b]	1.14%
Credit rating	BBB
Debt raising costs	0.125%
Cost of Debt	7.12%
Market risk premium	6.0%
Gearing Ratio (debt : equity)	60:40%
Value of Imputation Credits (gamma)	50%
Equity beta	1
Return to Equity	11.85%
Nominal Vanilla WACC	9.01%
Real Vanilla WACC	5.74%

* These amounts are indicative only. The final amounts will be determined by reference to market observations prior to the final decision.

Notes:

a. This figure is based on a 40 day average for the period ending 26 February 2007. Final values will be determined on a 40 day average for the period as agreed with the Regulator before the final decision.

b. This figure is based on a 40 day average for the period ending 26 February 2007, assuming a notional credit rating of BBB. Does not include allowance for debt-raising costs. Final values will be determined on a 40 day average for the period as agreed with the Regulator before the final decision.

GasNet has commissioned Synergies to provide a report in relation to the appropriate WACC for GasNet. However, as each of these parameters is consistent with the current regulatory precedent, GasNet only makes brief submissions in relation to each of the WACC parameters. If the Regulator proposes to move away from any of the parameters established by regulatory precedent, GasNet would welcome the prior opportunity to provide further submissions on the relevant parameter.

6.5 Risk free interest rate

For the purposes of the draft Access Arrangement and this Submission, GasNet has adopted a nominal risk free rate of 5.85% and a corresponding real risk free rate of 2.68%. This is based on the 10 year Commonwealth Government bond rate averaged over a forty day period ending on 26 February 2007.

The AER Compendium states that the AER will:

(a) use a 10 year government bond rate as a proxy for the risk free rate; and

(b) accept the period (between 5 and 40 days) used by the transmission network service provider to calculate the moving average of the risk free rate.[9]

The Commission has also adopted this position in its recent decisions relating to gas transmission regulation under the Code.[10]

The actual risk free interest rate adopted to calculate the WACC for the Third Access Arrangement Period will be calculated over a period ending on a date prior to the issue of the Commission's final decision. Consistent with its submissions on the Second Access Arrangement, GasNet requests that the Commission agree in advance with GasNet on the appropriate date to be used, with the outcome of that analysis to be included in the final decision. The advantages of this approach were outlined in GasNet's 2002 submissions.

6.6 Inflation forecast

Although the inflation forecast is not an explicit WACC parameter, it is required for the calculation of tax liabilities within the post-tax revenue model. As discussed later under the section 6.13 (Bias in Inflation Forecasts), it is important that the forecast of inflation be an unbiased estimate of future inflation.

Consistent with the approach taken for the Second Access Arrangement Period and established regulatory precedent, the inflation forecast is calculated from the observed real and nominal 10-year bond rates, using the Fisher Relationship as follows:

$$\text{Inflation Forecast} = (1+\text{nominal bond rate})/(1+\text{real bond rate}) - 1$$

For the purposes of this Submission, Synergies has derived a forecast for inflation of 3.09%.

Like the risk free interest rate, the actual inflation forecast used to calculate the WACC for the Third Access Arrangement period will be calculated over a period ending on a date prior to the issue of the Regulator's final decision. GasNet proposes that the same date agreed for the calculation of risk free interest rates be used.

6.7 Cost of debt

6.7.1 Debt margin

GasNet proposes to use its current actual credit rating of BBB to calculate the cost of debt for the purposes of the Third Access Arrangement Period. This is consistent with the Commission's benchmark credit rating associated with stand alone gas companies. In determining the appropriate benchmark credit

9 AER Compendium, at p21.

10 For example, see ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p93.

rating to use for the Access Arrangement for the Roma to Brisbane Pipeline, the Commission looked at the current credit rating of four stand alone gas entities and stated that:[11]

> *… all companies except for DUET had a credit rating of BBB. Although averaging the results may have indicated a rating marginally below BBB, it was evident that the credit rating associated with stand-alone gas companies was BBB. Accordingly, the ACCC considered APTPPL's proposal to apply a BBB credit rating to estimate its debt margin was appropriate and compliant with the code.*

A BBB credit rating is also supported by the Synergies report. Using the BBB credit rating, Synergies has calculated the difference between the 40 day average of the 10 year Commonwealth Government bond and the benchmark cost of 10 year BBB rated debt, for the period ending 26 February 2007 (sourcing data from Bloomberg). This results in a debt margin of 114 basis points.

6.7.2 Debt raising costs

Consistent with the Second Access Arrangement, GasNet has included its debt raising costs in the WACC. The debt raising costs are those administrative, legal and other transactional costs incurred in order to raise debt from time to time. Debt raising costs are particularly relevant to GasNet given the very large capital expenditure program planned for the Third Access Arrangement Period.

In 2004, the Commission commissioned a paper from the ACG[12] which considered the issue of appropriate debt and equity raising costs. The paper suggested a wide range of possible costs, depending on the size of the issues and other factors. However, the report was biased towards bond financing by regulated companies with stable cash flows over time. The report paid less attention to bank debt, timing issues and the debt raising requirements for large capital expenditure plans.

On the basis that the anticipated capital expenditure program exceeds the cash available from depreciation allowances, GasNet will need to raise debt and equity (under a benchmark company structure), with associated higher transaction costs. Therefore GasNet proposes to use a debt raising cost of 12.5 basis points per annum, but considers this to be at the lower end of the range permitted by the Code based on the 25 basis points per annum approved by the Australian Competition Tribunal for the Second Access Arrangement.

6.7.3 Cost of debt

The risk free rate of 5.85%, debt margin of 1.14% and debt raising costs of 0.125% results in a cost of debt of 7.12%.

[11] ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p95.

[12] 'Debt and Equity Raising Transaction Costs' Allen Consulting Group, December 2004

6.8 Market risk premium

For the purposes of the draft Access Arrangement, GasNet has adopted a market risk premium of 6.0%.

The Commission and State regulators have consistently adopted a market risk premium of 6% in recent regulatory decisions. The AER Compendium also adopts 6% as the relevant estimate.

Until recently the Commission had suggested that the market risk premium had fallen below 6%. However, in its most recent decision the Commission has found that the market risk premium remains around 6%. This is on the basis of a traditional long term view using historical measures, with the Commission acknowledging that considerable caution should be exercised in interpreting statistical results over shorter periods.[13]

Although GasNet accepts that 6% is within the range of outcomes permitted under with the Code, it submits that it is at the lower bound of the range.

Consistent with its Second Access Arrangement submissions, GasNet considers that the market risk premium has fallen. In addition to the submissions it has previously made[14], this is supported by the Synergies report.[15] In particular, in its report Synergies concludes that the range of market risk premium estimates which satisfy the Code requirements is between 6% and 7%. This is in part on the basis of Synergies' long-term average estimate of approximately 7%.[16] According to Synergies:

(a) there is considerable uncertainty surrounding the estimation of the market risk premium and it can be particularly volatile in the short term;

(b) as a result, studies over a longer period (at least 40 years) would be required before any conclusion that the market risk premium has fallen could be reached; and

(c) there is no evidence to demonstrate that the market risk premium has fallen.

6.9 Gearing

GasNet proposes to continue to employ a 60% gearing ratio. This is consistent with the Second Access Arrangement, and has been generally accepted by the Commission and State regulators in regulatory decisions. It is also supported by the Synergies report, which concludes that there is no justification for a higher value.[17]

13 ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p99.

14 GasNet 2002 submission dated 27 March 2002, p55-57.

15 See p48-50.

16 See p49.

17 See p27.

6.10 Imputation credits (Gamma)

Consistent with regulatory precedent, GasNet has adopted a value of 0.5 for gamma for the Third Access Arrangement Period. The Commission has generally accepted that 0.5 is compliant with the Code, including in its most recent decision.[18] The AER Compendium states that the AER will apply this to electricity transmission network service providers.

GasNet submits that 0.5 is now at the lower end of the range of outcomes for gamma that satisfy the Code. This is supported by the empirical analysis included in the Synergies report, which suggests that gamma has fallen. In its report, Synergies actually concludes that the value of gamma is now likely to be zero.[19]

Further, a recent paper by Handley[20] suggests that the historical estimation of the market risk premium is linked with the value selected for gamma, such that a higher gamma is associated with a higher estimate for the market risk premium (greater than 6%), and vice versa. Thus any shift away from the current standard of 0.5 must take into account the impact on the market risk premium estimate.

Accordingly, GasNet submits that if any adjustment is to be made to the gamma value established by regulatory precedent, it should take into account the corresponding effect on the market risk premium and furthermore should be in the direction of zero rather than one.

6.11 Tax allowances and normalisation

GasNet proposes to use a post-tax revenue model, in which the tax liability is calculated explicitly. The allowance for tax is then determined by applying the gamma factor to the calculated tax each year.

The tax liabilities are calculated as zero for the Third Access Arrangement Period. However, because tax liabilities are expected to increase sharply over the subsequent Access Arrangement Periods, GasNet has in the past employed a normalisation process whereby an additional amount of depreciation was claimed. The intent was to generate a smoother tariff transition between the current period when taxes are zero and future periods when deferred taxes form part of the Total Revenue determination. The additional revenues amounted to approximately $2.5 million per annum, and the Capital Base was written down by the associated amount of depreciation. However, the issue of future tax liabilities and how they impact on the tariff path is now of secondary importance to the issue of how capital expenditure will impact on the tariff path.

In this light, GasNet proposes not to claim an additional amount for normalisation depreciation.

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18 ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, at p91.

19 See at p53.

20 Brailsford. T, Handley J et al, “A re-examination of the historical equity risk premium in Australia” April 2007.

6.12 Equity beta

Consistent with regulatory precedent, GasNet proposes to adopt an equity beta of 1. This value is consistent with an asset beta of 0.40 and an assumed debt beta of 0.

GasNet is proposing a value of 1 for the equity beta because it is the general consensus view amongst regulators and has been consistently adopted by the Commission in its decisions on gas transmission pipelines in recent years. It is also adopted in the AER Compendium.

However, GasNet takes the view that an equity beta of 1 is at the lower bound of the range of outcomes which would be permitted under the Code. In addition to the submissions and supporting data provided in relation to the Second Access Arrangement, the Synergies report supports the view that an equity beta of 1 is at the lower bound of the range. In fact, the Synergies report concludes that an estimate between 1 and 1.2 is appropriate, based on an assessment of comparable companies which is outlined in detail in the report. Accordingly, GasNet submits that there is no justification for adopting an equity beta lower than 1.

6.13 Bias in Inflation Forecasts

The forecast of the real and nominal risk free rates is a key input into the WACC. These rates form the base from which both the cost of debt and the cost of equity are calculated.

As noted above in section 6.5, GasNet has used the 10 year Commonwealth Government bond rates, as measured over a 40 day period at a date as close as practicable to the start of the Third Access Arrangement Period, to estimate this parameter.

The real risk free rate is taken to be the measured rate applicable to index-linked government bonds, and the nominal rate is taken as the measured rate applicable to nominal government bonds.

It has been standard practice in the past to forecast the inflation rate as the difference between the nominal and index-linked bond rates (that is, using the Fisher relationship as proposed by GasNet in section 6.6 above).

Because the GasNet Reference Tariff is indexed to the actual outturn inflation, the calculation of Total Revenue only requires the real risk free rate (with the exception of a small sensitivity of the taxation calculations to the forecast of inflation). That is, in the calculation of the Reference Tariffs applicable at the start of the Third Access Arrangement Period, the forecast of inflation and the nominal risk-free rate have very little consequence.

However, there are circumstances in which the forecast of inflation, and the nominal risk-free rate, can have a significant impact.

The assumption implicit in the determination of the Total Revenue and the Reference Tariffs in accordance with the WACC methodologies employed by the Commission is that the company borrows against index-linked bonds. However, if the company borrows at fixed nominal rates (as is most common amongst regulated utilities given that the market for index-linked bonds is thin), then the inflation outcome is critical. If actual inflation differs from the forecast, (meaning that actual revenues will differ from the forecast) then the company will be exposed to additional risk, since the allowance for interest costs factored into the Total Revenue will no longer match the actual interest payments on the nominal debt.

This risk is most relevant if the forecast of inflation is biased. There is reason to believe that the current limited supply of index bonds may have led to a bias in the estimates of inflation derived using the Fisher relationship. For example, in the February Statement of Monetary Policy, the RBA states[21]:

> *"The implied medium-term inflation expectations of financial market participants, as measured by the difference between nominal and indexed bond yields were around 3¼ per cent in early November. However, as noted in previous Statements, this measure can be affected by factors unrelated to expectations about inflation, such as changes in institutional demand for indexed securities."*

If the RBA is correct, then current measures of inflation are biased, which would have significant ramifications for the determination of the WACC.

If it is accepted that 10-year the index-linked bond rate is the true inflation-free expectation of future bond rates, then under the standard approach the expectation for nominal bond rates is formed by adding the expected inflation rate to the index-linked rate (the Fisher relationship).

However, in periods of greater uncertainty it is possible that the expectation of future nominal rates may also include a premium for the risk that the expected inflation will differ from actual inflation. If this is the case, then the nominal rate is no longer an unbiased estimate of the index-linked rate plus forecast inflation, and a regulated company which borrows against nominal bonds will suffer a revenue shortfall under the real rate of return revenue model.

This issue was discussed at some length by the ESC in the recent 2005 electricity distribution decision.[22] The ESC rejected the argument for an inflation risk premium on the basis that the Fisher relationship was yielding forecasts consistent with the Reserve Bank inflation target of 2-3%.

However, the ESC's argument is not conclusive and, in GasNet's opinion, it leaves open the possibility that the standard WACC methodology under-estimates the true WACC. In the absence of more definitive evidence, GasNet is not claiming an allowance for an inflation risk premium, but notes that there is the possibility of a one-way bias that supports a higher WACC.

That said, GasNet notes that if the inflation forecast calculated by the Fisher relationship exceeds the target band of 2-3% used by the Reserve Bank, then there is a greater cause for concern. This is because there is an implication that the financial markets are pricing in a premium for the risk that the Reserve Bank will not be successful in its monetary targets. GasNet notes that the inflation forecast of 3.09% estimated by Synergies using the Fisher

[21] See p59.

[22] ESC, *Electricity Distribution Price Review 2006-10 Final Decision*, October 2005.

relationship exceeds the Reserve Bank target (see section 6.6 above). If the actual inflation forecast adopted in the final decision also exceeds the Reserve Bank's target, GasNet submits that the inflation forecast should be capped at 3%, and the real risk-free rate used in the final decision should be calculated as the difference between the observed nominal rate and 3%.

GasNet also submits that, even if the inflation forecast is calculated to be less than 3%, there should be a consideration of possible bias in the formation of nominal and indexed bond rates due to institutional factors, as discussed by the RBA, and an appropriate adjustment made to the risk free rate.

6.14 Specific risks

Consistent with regulatory precedent and GasNet's submissions on the Second Access Arrangement, specific (asymmetric) risks are discussed in section 9 of this Submission (Non Capital Costs), along with other Non Capital Costs such as operating and maintenance costs.

7 Forecast capital expenditure

7.1 Summary of GasNet's proposals

A summary of the forecast capital expenditure for the Third Access Arrangement Period is set out in Table 7.1. An explanation of each of the items identified in Table 7.1 is provided below.

All costs in this section are expressed in $2006 for ease of comparison.

The figures below do not incorporate interest during construction, which is included in the calculation of the Target Revenue going forward.

Table 7.1: Estimated Capital Expenditure ($2006 Dec million)

	2008	**2009**	**2010**	**2011**	**2012**
Augmentations					
Northern Zone		79.03			
Sunbury loop					12.46
Ballarat loop			29.03		
Warragul loop		4.84			
Pakenham		1.22			
Stonehaven Compressor					26.17
Carisbrook Loop			24.05		
Brooklyn Lara (Corio) pipeline	63.71				
Brooklyn Wollert easements			5.37		
Total augmentations	**63.71**	**85.12**	**58.45**	**0**	**38.63**
Refurbishments and Upgrades					
Gas heating facilities	7.22	1.99			
City gate works	6.68				
Pipeline upgrades	2.45	4.13	0.89	1.29	0.89
Safety and Security systems	3.41	0.84			
Brooklyn compressor station		37.76		11.81	

	2008	2009	2010	2011	2012
Wollert compressor station		1.58			
Other compressor stations	1.34				1.62
Other	1.76	0.36	0.43	0.82	0.93
Total refurbishments and upgrades	**22.87**	**46.65**	**1.32**	**13.92**	**3.43**
Total capex	**86.57**	**131.77**	**59.76**	**13.92**	**42.08**

7.2 Code requirements

In addition to the roll-forward of the Capital Base, the Code describes a number of supplementary components to be included in calculating the Total Revenue. In particular, sections 8.20 to 8.22 (inclusive) of the Code outline how forecast capital expenditure, or New Facilities Investment, may be included in the Capital Base.

Under section 8.20 of the Code, forecast New Facilities Investment can only be included if it is reasonably expected to pass the requirements in section 8.16(a) (discussed in section 7.4.1 below).

A New Facility includes any extension or expansion of the capacity of the pipeline, or any capital asset constructed, developed or acquired, to enable the Service Provider to provide Services.

As noted in section 5.6 above, section 8.16(a) of the Code comprises a two part assessment for determining whether New Facilities Investment incurred during an Access Arrangement Period qualifies for inclusion in the Capital Base.

7.3 GasNet's proposal

7.3.1 Overview

GasNet has forecast capital expenditure of $334.08 million ($2006) for the Third Access Arrangement Period. The main items of capital expenditure include:

(a) duplication of several sections of PTS pipeline (at Ballarat, Carisbrook, Wollert, Warragul, Pakenham and Sunbury);

(b) installation of compressors at Euroa and Stonehaven;

(c) upgrade and redevelopment of the Brooklyn and Wollert compressor stations; and

(d) other refurbishment capital expenditure.

Each of these items is discussed in sections 7.5 and 7.6 below.

7.3.2 *Required capital expenditure*

GasNet has prepared its capital expenditure plan for the Third Access Arrangement period in two parts:

(a) augmentation capital expenditure; and

(b) refurbishment and upgrade capital expenditure.

Augmentation capital expenditure is required to increase the capacity of transmission assets to ensure that the PTS can continue to supply Services as demand grows.

Refurbishment and upgrade capital expenditure is generally required to maintain the service potential of existing facilities as they age and deteriorate over time, but it also includes expenditure to upgrade and improve assets because of obsolescence, to deal with changed operating circumstances (such as a wider gas specification), to meet new regulatory or legislated obligations, or to meet higher environmental and safety standards over time.

It is important to note that when optimising the development of the PTS, the distinction between refurbishment and augmentation can become blurred, as there will be a degree of overlap in these plans.

For example, where assets are near the end of their life but at the same time are requiring augmentation to increase capacity, it is more efficient to replace the assets with larger units rather than add smaller units to existing facilities. This is cost effective in both the short and the long term, as it provides a more efficient base for future growth.

7.3.3 *Methodology*

<u>Augmentations</u>

In the latest VENCorp APR, VENCorp has identified the likely emergence of network constraints on various Pipelines in the PTS from around 2007 to 2008 onwards. These constraints are expected to emerge because of increasing load growth in the Victorian market. If the augmentations are not undertaken, this anticipated load growth will lead to breaches of the minimum system pressures as prescribed in the VENCorp System Security Guidelines and the connection deeds between VENCorp and the relevant distribution businesses. The distribution companies rely on these minimum pressure obligations to manage and plan their systems.

VENCorp and GasNet have been working together as part of the NDWG, to analyse in detail the impact of the constraints and the best options to maintain system security.

As an outcome of the work of the NDWG, VENCorp has prepared a number of network timing and planning reports, which:

(a) identify the anticipated constraints;

(b) estimate the timing of when the constraint is expected to arise;

(c) compare and review a number of options to respond to the constraint, which takes into account the costs of the options relative to their ability to respond, in an appropriate time frame, to the anticipated constraint; and

(d) where appropriate, propose a preferred response to the constraint.

GasNet has included as Attachment A to this Submission VENCorp's network timing and planning reports, which support a substantial component of GasNet's forecast capital expenditure. GasNet has also attached the Description Report and the Compressor Strategy in support of GasNet's proposed augmentation capital expenditure.

The proposed augmentation capital expenditure (which is discussed in detail below in section 7.5) will ensure that minimum system pressures are maintained during the Third Access Arrangement Period and beyond, and that GasNet will continue to maintain the safety and integrity of Services on the PTS.

Refurbishment and upgrade capital expenditure

Upgrading and replacement of assets is required to ensure that Services can be provided on a sustainable basis in light of the aging and deterioration of equipment and changed regulatory and legislative requirements, including safety and environmental considerations.

Refurbishment capital expenditure often involves a large number of small projects which can be characterised as 'stay-in-business' capital expenditure, and which cannot be separately analysed. However there are a number of major refurbishment projects planned for the Third Access Arrangement Period, and GasNet has provided detailed analysis and justification for these projects below in section 7.6.

In support of GasNet's proposed refurbishment capital expenditure, GasNet has attached the Compressor Strategy, which is a comprehensive review of the status and redevelopment plans for its compressor facilities.

7.4 Application of section 8.16 tests

7.4.1 Application of section 8.16(a) tests to forecast capital expenditure

As noted in section 5.6 above, section 8.16(a) of the Code comprises a two part assessment for determining whether New Facilities Investment incurred during an Access Arrangement Period qualifies for inclusion in the Capital Base.

In terms of the Prudency Test, GasNet's forecast expenditure for the proposed augmentations is based on GasNet's past experience with similar projects, projected materials and resources required as set out in GasNet's Description Report. GasNet considers that the forecast capital expenditure reflects a level of investment which is prudent to achieve the service standard in a technical and engineering sense. In particular (and where justified by the size of the project), tenders have been or will be sought for works under each project in order to find the most efficient and lowest final cost solution.

On this basis, GasNet considers that the proposed augmentations also represent the most cost-effective and efficient response to the identified potential constraints, and would satisfy the requirements of the Prudency Test.

For the reasons set out below, GasNet believes that all of the augmentations (other than the Stonehaven Compressor) would satisfy the System Integrity Test. As such, that test is the focus of this Submission. However, where applicable, GasNet has also applied the System-Wide Benefits Test.

7.4.2 System Integrity Test

The System Integrity Test requires that the New Facility be necessary to maintain the safety, integrity **or** contracted capacity of Services. The use of the word "or" means that it is sufficient if one of these criteria is satisfied. On this basis, GasNet considers that the "contracted capacity" element of the test is not relevant to this analysis in GasNet's case.

The System Integrity Test is not elaborated on in the definitions section of the Code and therefore it is necessary to interpret the ordinary meaning of the test.

Integrity is defined as "the state of being whole, entire or undiminished" or of "sound unimpaired or perfect condition". Further, safety is referred to as "the quality of insuring against, hurt, injure, danger or risk". In the context of gas transmission system safety and integrity, it would refer to all parts of the physical facilities through which gas is transported, including pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

In relation to the PTS, one of the key components in providing the Services to VENCorp is maintaining the minimum system pressures. Without the augmentations, the minimum system pressures would not be maintained resulting in uncontrolled and unpredictable outages near the fringe points of the connected distribution networks. These outages could also subsequently impact on the safety of the gas networks. On this basis, the augmentations are required to maintain the integrity of the PTS.

A related component to providing safe and secure Services to VENCorp is the requirement that access to such Services is to be provided to all Users. Consequently, in providing this access the Market Carriage System does not distinguish between historical and new Users.

Therefore, as Market Carriage systems are required to give access to both existing and new Users, the proposed augmentations to the transmission system must be implemented to provide access for these Users to a secure system.

7.4.3 System-Wide Benefits Test

The System-Wide Benefits Test requires that the Regulator be satisfied that the forecast new facilities investment would generate system-wide benefits that in turn would justify a higher reference tariff for all Users. GasNet notes that the Code provides no guidance as to the threshold level of system-wide benefits that must be established in order to roll in a New Facilities Investment under the System-Wide Benefits Test. Regulatory precedent simply establishes that where an applicant proposes to recover the costs of a new asset through a substantial increase in the reference tariffs for all users, the system-wide benefits must be substantial.[23]

Further, the Commission has recognised that the benefits of a proposed New Facility need not accrue equally to all users to be considered system-wide. The Commission stated in the Interconnect Decision that it:

> *does not interpret the Code to require that system-wide benefits would accrue equally and simultaneously to all users. … Rather, benefits should be available across the system and potentially be available to much of the customer base.*[24]

7.5 Proposed augmentation projects

7.5.1 Northern Zone

Currently, GasNet has an allocation of 17 TJ of AMDQ for export of gas through Culcairn. Under the MSO Rules, any exports through Culcairn up to 17 TJ per day must have priority over non-authorised loads, as long as gas is being injected to match the withdrawal. This allocation was made at the commencement of the market when the capacity of the PTS was sufficient to carry this level of exports to NSW through the Interconnect Pipeline.

In its paper *VENCorp Planning Report (P003) - Northern Zone (Planning) of March 2007*,[25] VENCorp has identified that there is currently insufficient capacity in the Northern Zone to achieve the 17 TJ exports through Culcairn on days of high system demand given the average annual demand growth of 2.7% between 1999 to 2010 in the Northern Zone.

There is currently a high likelihood that NSW exports will grow from current levels of about 3 PJ/year to 5 PJ/year in 2010, to supply a number of users including the Uranquinty power station near Wagga Wagga. These users have expressed interest in obtaining an allocation of the export AMDQ, which would give them priority over other users in Northern Victoria who have exceeded their original allocations.

While historically there have been imports of gas from Culcairn (generally in the winter period), there is no assurance that this will continue into the future. These flows have been highly variable and appear to be opportunistic in nature. It is GasNet's view that it is not appropriate to rely on opportunistic flows in planning for the security of the system.

In order to respond to this anticipated constraint, GasNet proposes to undertake the Northern Zone augmentation, which comprises:

(a) an upgrade of the Wollert compressor station (which is discussed in section 7.6.6 below) ($39.56 million);

[23] Interconnect Decision, p27.

[24] Interconnect Decision, pvi.

[25] Attached as part of Attachment A to this Submission.

(b) partial duplication (11km) of the Wollert to Wandong pipeline downstream of the Wollert compressor station to Line Valve 3 in 450mm pipe (which is described in section 4 of the Description Report) ($14.56 million); and

(c) installation of a compressor at Euroa (as set out in section 4.6 of the Compressor Strategy) ($24.92 million).

The Northern Zone augmentation is expected to be commissioned and completed prior to winter 2009 at a total cost of $79.03 million.

The total capital expenditure includes an amount of $39.56 million at Wollert which will provide the required increase in compressor power. However, it also incorporates replacement of the existing aging Wollert compressor station facilities, which would otherwise require significant expenditure.

This is an optimised strategy which takes advantage of the requirement to replace the aging assets at the Wollert compressor station at about the same time as the augmentation is required, and to meet the directive from Energy Safe Victoria to replace wet-seal compressors with dry-seal units, as discussed in section 7.6.6 below.

The proposed Northern Zone augmentation is the preferred strategy amongst a number of options to meet the anticipated constraint in the Northern Zone. The merits of each option, and the reasons for recommending the preferred plan, are discussed in the VENCorp Planning Report (P003).

7.5.2 Sunbury loop

In its paper *Network Planning Report - P001, Sunbury Lateral (Planning) of March 2007*,[26] VENCorp has identified that the increasing load along the Sunbury lateral has raised the prospect of the minimum delivery pressure at Sunbury, Sydenham and Diggers Rest being breached in winter 2012.

In order to respond to this anticipated constraint, GasNet proposes to undertake the partial duplication of 14.9km of the Sunbury lateral in 200mm pipe.

The Sunbury lateral augmentation integrates with the upgrade of compressor facilities at the Brooklyn compressor station (discussed in paragraph 7.6.3 below).

Assuming the Brooklyn compressor station redevelopment proceeds, the Sunbury duplication is required by winter 2012. However, if the redevelopment does not proceed, this augmentation will be required in 2009. A more detailed description of the project is contained in the Description Report.

The cost of the project is $12.46 million.

The proposed augmentation is the option recommended by VENCorp in its report having evaluated several options to remedy the constraint. The merits of each option are discussed in the VENCorp Planning Report (P001).

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[26] Attached as part of Attachment A to this Submission.

7.5.3 *Ballarat (Mt Franklin to Ballan Loop)*

In its paper *Network Planning Report (P002) - Ballarat (Planning) of March 2007*,[27] VENCorp has identified that the increasing load along the Brooklyn to Ballarat pipeline raises the likelihood of the minimum delivery pressure at Ballarat being breached during winter 2010. The constraint will cause the pressure at the inlet to Ballarat city gate to fall to a level that will breach the VENCorp System Security Guidelines.

In order to respond to this anticipated constraint, GasNet proposes to undertake the Ballarat augmentation which comprises duplication of the 40.1km of 150mm pipeline between Mt Franklin and Ballan with a 300mm pipe.

The Ballarat augmentation is expected to be commissioned and completed prior to constraints anticipated in winter 2010 at a cost of $29.03 million. A more detailed description of the project is contained in the Description Report.

The proposed Ballarat augmentation is the option recommended by VENCorp in its report having evaluated several options to remedy the constraint. The merits of each option are discussed in the VENCorp Planning Report (P002).

7.5.4 *Warragul duplication*

In its paper *Network Planning Report - Warragul (P004) of March 2007*,[28] VENCorp has identified a potential constraint on the Lurgi pipeline in winter 2009, due to:

(a) general growth in the area serviced by the Pipeline (Pakenham South, Cranbourne and Lyndhurst); and

(b) proposed expansion of production in respect of a large commercial customer, which would lead to a subsequent increase in load.

In order to respond to the anticipated constraint GasNet proposes the Warragul augmentation, which comprises the duplication of a section of the Warragul branch Pipeline of approximately 4.8 km in length with 150mm pipe. GasNet believes the marginally higher cost of the 150 mm pipe compared with the 100 mm option is justified by the deferral of future augmentation.

The Warragul augmentation is expected to be commissioned and completed prior to anticipated constraints in winter 2009 at a cost of $4.84 million. A more detailed description of the project is contained in the Description Report.

The proposed Warragul augmentation is the option recommended by VENCorp in its report, having evaluated several options to remedy the constraint. The merits of each option, and the reasons for recommending the preferred plan, are discussed in the VENCorp Planning Report (P004).

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[27] Attached as part of Attachment A to this Submission.

[28] Attached as part of Attachment A to this Submission.

7.5.5 *Pakenham*

In its paper *Network Planning Report (T006) - Pakenham (Timing and Planning) of March 2007,*[29] VENCorp has identified a potential constraint on the Lurgi (Morwell-Dandenong) pipeline due to higher than average growth (of around 7% per annum with about 1000 new customers per year) at Pakenham. This has raised the prospect of excessively high gas velocity during winter 2009.

In order to address concerns with anticipated high gas velocity, GasNet proposes to undertake the Pakenham augmentation (which supplements the Warragul augmentation). The Pakenham augmentation comprises the duplication of the remaining 0.45km of 80mm section of the Pakenham South branch with 150mm pipe. It is expected to be commissioned and completed prior to anticipated issues in winter 2009 at a cost of $1.22 million.

As noted in the VENCorp Timing and Planning Report (T006), velocities above 15m/s are inconsistent with maintaining the integrity of the pipeline. VENCorp considers that without the augmentation, forecast average gas velocity will be above 20m/s over the Third Access Arrangement Period, which is significantly above the recommended limit of 15m/s. The potential effect of this anticipated high velocity is that the integrity of the Pipeline and related infrastructure would be negatively impacted (in particular the regulators and valves), thus raising concerns that the supply of Services to these areas could also be affected, with potential for disruption to Services. In addition, excess noise could potentially breach EPA noise regulations.

GasNet considers that the Pakenham augmentation will resolve these concerns and maintain the integrity of Pipeline infrastructure in the Pakenham region.

The proposed Pakenham augmentation is recommended by VENCorp in its report. However, VENCorp has considered only one option to respond to the forecast high gas velocities. That is because the augmentation is the only practical response to the forecast high gas velocities.

7.5.6 *Stonehaven compressor*

In its *Network Planning Report (P007) - Stonehaven (Planning) of April 2007,*[30] VENCorp provides an analysis of the potential system-wide benefits that may arise from the installation of a compressor at Stonehaven.

GasNet believes that the Stonehaven augmentation is a logical staged development which supplements the construction of the Brooklyn Lara (Corio) pipeline (scheduled to be completed by March 2008) and will increase the system capacity by 65 TJ. The cost of this augmentation is expected to be $26.19 million. A more detailed description of the project is contained in the Compressor Strategy.

VENCorp's analysis indicates that the completion of the Stonehaven augmentation (which involves the installation of a compressor at Stonehaven)

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29 Attached as part of Attachment A to this Submission.

30 Attached as part of Attachment A to this Submission.

prior to winter 2013 has the highest net market benefits. However, VENCorp has included a number of caveats in its Planning Report (P007) and acknowledges that there is considerable uncertainty in regard to the appropriate timing of the Stonehaven augmentation.

GasNet submits that the augmentation should be completed prior to winter 2012. VENCorp has used a discount rate of 7% in its modelling, however, GasNet believes that its proposed real WACC of 5.74% is the appropriate discount rate. If this rate is used, GasNet has determined that completion of the Stonehaven augmentation prior to winter 2012 has the highest net market benefits.

While GasNet has chosen to focus predominantly on the System Integrity Test in this Submission, it has also chosen to specifically apply the System-Wide Benefits Test in relation to the Stonehaven augmentation. If, as proposed above, GasNet's real WACC is used as the discount rate, the Stonehaven augmentation will offer system wide benefits that would justify completion of the augmentation in 2012.

The VENCorp Planning Report (P007), adopted an economic-cost benefit analysis comparing the installation of one or two compressors. While additional benefits would be gained from the installation of two compressors, the report noted that the net market benefits would be significantly higher with installation of one compressor (refer to Table 5 - Net Market Benefits in the VENCorp Planning Report (P007)). This was mainly a result of the significant increase in cost for installation of two compressors ($48 million).

GasNet submits that the system-wide benefits arising from the Stonehaven augmentation are sufficiently "substantial", in that their present value exceeds the forecast costs of the investment. GasNet has previously acknowledged in its section 8.21 submission[31] to the Commission that the benefits of the Corio Loop (to which the Stonehaven augmentation relates) may not always be enjoyed equally by all PTS users, however, the Commission has recognised that benefits need not accrue equally to all users to be considered system-wide.[32]

The cost of the Stonehaven compressor station reflects the fact that it is a greenfields site and therefore additional costs will need to be incurred before construction can commence such as obtaining the appropriate planning and environmental permits.

7.5.7 Carisbrook Loop

The *GasNet Planning Report - Carisbrook (Planning & Timing) of March 2007*,[33] identifies a potential constraint in winter 2010 due to increased demand along the Guildford to Carisbrook pipeline.

In order to respond to the anticipated constraints, GasNet proposes to undertake the Carisbrook Loop augmentation. The proposed Carisbrook

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[31] GasNet Australia, application under section 21 of the Gas Code in relation to forecast New Facilities Investment, 21 December 2005, p18.

[32] Interconnect Decision, pvi.

[33] Attached as Attachment B to this Submission.

Loop augmentation comprises the duplication of the existing 31.4 km section of 150mm pipeline from Guildford to Carisbrook with 300mm pipe and is expected to be commissioned and completed prior to anticipated constraints in winter 2010 at a cost of $24.05 million. A more detailed description of the project is contained in the Description Report.[34]

Several options were considered in order to respond to the constraint. The merits of each of these options are discussed in the GasNet report.

7.5.8 Brooklyn Lara (Corio) pipeline

As discussed in section 5.8.1 above, GasNet commenced construction of the Brooklyn Lara (Corio) pipeline in 2006, but the project will not be completed until prior to winter 2008. Consistent with the "as commissioned" methodology previously applied by GasNet in respect of capital expenditure, the 2006 and 2007 costs for the Brooklyn Lara (Corio) pipeline must be included in the Third Access Arrangement Period.

Accordingly, the Brooklyn Lara (Corio) pipeline is to be completed during the Third Access Arrangement Period at a cost of $63.71 million.

As the Commission has already agreed that the forecast capital expenditure satisfies the requirements of section 8.16(a) of the Code as part of the Second Access Arrangement, GasNet considers that the proposed augmentation would also satisfy Code requirements for the Third Access Arrangement Period.

7.5.9 Brooklyn Wollert loop - Acquisition of easements

The Brooklyn Wollert loop comprises a gas pipeline that will eventually be needed to connect the Pakenham to Wollert Outer Ring Main at Wollert to the Brooklyn Compressor station and the Brooklyn Lara (Corio) pipeline. It will enable the exchange of large quantities of gas between the west (supplied from Port Campbell) and the east (supplied from Longford) and greatly increase the operational flexibility and line-pack management of the PTS. Currently there is no direct high pressure link between the east and west, since the pipeline through Melbourne is of limited capacity and is operated at lower pressures. GasNet considers that this pipeline is vital to the future operation of the PTS. Based on current projections, it is likely to be required sometime between 2015 and 2020.

However, there is a high risk that it will not be possible to construct the pipeline along the preferred route due to anticipated urban encroachment between now and 2015. If this occurs, the pipeline will have to follow a longer route to avoid the newly built-up areas, at significantly greater cost.

Therefore GasNet proposes to acquire the easements as soon as possible. This is expected to cost $5.37 million which includes preliminary environmental studies.

The Brooklyn Wollert loop is likely to cost in excess of $100 million on the currently planned route. Acquiring the easement now for $5.3 million is justified in NPV terms if the alternative is to spend 7 per cent to 10 per cent more when the pipeline is required in 2015 to 2020. Given the risk of urban encroachment in the area, it is likely that an alternative route at that time will be over 10 per cent longer than the current planned route.

The impact of urban encroachment on access to easements is an issue that was highlighted in the 2005 VENCorp document "Vision 2030". As stated in the executive summary of that document:

> *This document has demonstrated the need for a detailed audit of all existing electricity and gas easements to identify the potential additional capacity they can accommodate, as well as any measures required to protect future access to easements and sites required to meet future needs outlined in this vision.*

VENCorp has instituted a program to review access issues which is due to report in 2008. GasNet will participate in this program, but has identified the Wollert to Brooklyn easement as a high priority for the purposes of the Third Access Arrangement Period.

7.6 Refurbishment and Upgrade projects

7.6.1 Overview

GasNet has included an allowance in each Regulatory Year of the Third Access Arrangement Period for refurbishment and upgrade capital expenditure. Total expenditure is forecast to be $88.19m. The forecast refurbishment and upgrade capital expenditure includes:

(a) compressor upgrades in line with the Compressor Strategy and options discussed in the VENCorp reports;

(b) control system upgrades and gas heating facilities;

(c) safety and security upgrades;

(d) general pipeline upgrades; and

(e) general maintenance and stay in business capital expenditure.

The key drivers of the refurbishment capital expenditure are:

(a) the age of assets and equipment; and

(b) regulatory requirements relating to safety, security and the environment.

GasNet submits that the refurbishment capital expenditure is required to maintain the safety and integrity of the system. Further, GasNet considers that the refurbishment capital satisfies the Prudency Test as the expenditure represents the most cost effective response to operational requirements and is based on GasNet's past experience during the previous regulatory periods.

7.6.2 Gas heating facilities

The gas heater augmentation project comprises the installation of water bath-style gas heaters at a number of sites around the PTS. These are expected to be commissioned and completed during the Third Access Arrangement Period at a cost of $9.21 million (refer to section 5.7.3 above).

The sites at which the water bath heaters are proposed to be installed, together with the associated costs, are set out below:

(a) the Lara city gate ($0.5m);

(b) the Brooklyn city gate ($2.27m);

(c) the Dandenong city gate ($3.44m);

(d) the Wandong city gate ($1.18m);

(e) the Clonbinane city gate ($0.81m);

(f) the North Laverton city gate ($0.51m); and

(g) the DTS Morwell Back-up regulator ($0.50m).

The requirement for gas heating facilities arises from the fact that when gas pressures are reduced at a regulator station, there is an associated fall in gas temperature which can have negative effects on downstream assets. For example:

(a) ice can form on control equipment leading to operational failures;

(b) hydrates could form in the Pipeline system; and

(c) gas liquids can form in the gas stream if the gas composition contains higher components (e.g. propane).

Depending on the gas composition and the extent of the pressure drop, it may be necessary to pre-heat the gas to avoid these harmful effects.

The *Victorian Gas Safety Regulations* stipulate a minimum temperature standard for gas conveyed in a transmission pipeline of 2^{o}C.[35] GasNet's capital expenditure on heaters is designed to meet this standard.

Currently GasNet maintains small heaters at the Brooklyn and Lara city gates (which require upgrades) and is in the process of installing one at the Dandenong terminal station (feeding the small Lurgi Pipeline). Additional heating is required in the Third Access Arrangement Period because forecast growth in injection volumes and new injection sources (such as Yolla and Otways gas) means that the PTS must have the facilities in place to handle higher components in the gas stream, and higher linepack and system pressures.

Cost estimates for the augmentation reflect the size of the heater that is

[35] Refer to Schedule 2 of the Gas Safety Regulations.

needed.

7.6.3 *City gate works*

An upgrade is required for the Brooklyn, Lara and Dandenong city gate sites. The upgrades are forecast to be completed during 2008 at a cost of $6.68 million.

The Brooklyn city gate works comprise upgrades to:

(a) the instrument air system;

(b) the fuel gas system;

(c) liquids collection facilities;

(d) the control valves;

(e) bypass facilities (which facilitate gas supply to Geelong); and

(f) the Ballan pressure limiter.

The Lara city gate works comprise upgrades to the liquids collection facilities and regulator controls, and a fuel gas meter.

The Dandenong city gate works were originally approved for the Second Access Arrangement period but have been delayed due to commitments at a number of other locations and long lead times for the ordering of necessary equipment.

GasNet confirms that the reasons for conducting upgrades to the city gate sites remain the same as was stated in GasNet's Submission on the Second Access Arrangement and as noted in section 5.7.3 of the historical capital expenditure section.

7.6.4 *Pipeline Upgrades*

GasNet plans to spend $9.65 million over the next Access Arrangement Period on upgrades to the PTS.

On-going work includes investment in cathodic protection facilities, pipeline recoating, and pipeline risk assessments under AS2885. Additional projects include upgrades to pig traps (2008), line valve automation (2009) and emergency vent upgrades (2011).

An upgrade of the pig traps on the Keon Park to Wollert pipeline is to be completed during the Third Access Arrangement Period at a cost of $2.45 million. The pig trap upgrade is required so that pigging can be performed on the Pipeline and an assessment made of the integrity and quality of the Pipeline.

The line valve automation project comprises the installation of control equipment at fifteen sites along the Dandenong to Brooklyn Pipeline where line valves are provided for emergency isolation of the pipeline. Because of the difficulties of accessing the existing equipment (as it is in a built-up area), the control equipment will allow for reliable remote operation. The line value automation is to be commissioned and completed during the Third Access Arrangement Period at a cost of $4.13 million.

In addition to allowing the reliable remote operation of the system, the automation of the T1 and T2 line valves would, in the event of a Pipeline rupture:

(a) limit disruptions to supply;

(b) enable faster shut down of the system and therefore minimise damage to people and property; and

(c) permit quicker, safer and more timely access to the line valves in the case of an emergency.

An upgrade to the pipeline emergency vents is required at a cost of $1.29 million in 2011. The existing vents are in poor condition and require renewal.

7.6.5 *Safety and security*

GasNet proposes to make further security upgrades to the PTS during the Third Access Arrangement Period. These upgrades continue the projects described in section 5.8.6 (Safety and Security Systems). It is anticipated security systems will be installed at the Gooding, Brooklyn and Wollert compressor stations, and at Longford and the Lara city gate.

The expenditure includes:

(a) alarm systems;

(b) security fencing;

(c) lighting; and

(d) close circuit television and related communications requirements.

In addition, GasNet will purchase additional stocks of equipment to be kept for use in an emergency. The total cost of these security projects is expected to be $2.93 million.

GasNet also proposes to continue the risk assessment of hazardous area equipment during the Third Access Arrangement Period as described in section 5.8.6, at a cost of $1.32 million.

The project will assess the risk where electrical equipment operates in areas potentially subject to gas leaks, and will replace and upgrade the electrical equipment and instrumentation to the required standards.

7.6.6 *Compressor upgrades*

Capital expenditure is required at each compressor station on the PTS over the Third Access Arrangement Period with the major work required at Brooklyn and Wollert. The factors driving the requirement for upgrades at the Brooklyn and Wollert compressor stations are:

(a) the age and obsolescence of the compressor stations; and

(b) the regulatory impact of the increased safety requirements adopted by Energy Safe Victoria which require that all gas companies take every appropriate step to prevent the entry of liquids into gas transmission and distribution networks (as noted under section 5.8.1 (Brooklyn compressor station redevelopment)).

As such, forecast capital expenditure for the Third Access Arrangement Period reflects requirements to upgrade the aging facilities and install dry seal compressors.

GasNet's Compressor Strategy identifies system requirements and sets out the program and strategy for redevelopment and upgrade (as applicable) of the aging and obsolete assets (which is prioritised in terms of opportunity and importance).

GasNet considers that this refurbishment capital expenditure is the most efficient response to future requirements of the PTS.

<u>Brooklyn compressor station</u>

GasNet will complete the refurbishment of the Brooklyn compressor station by 2009. This work carries over from the historical capital expenditure discussed in section 5.8.1. In addition, an existing unit will be relocated during 2011. The forecast cost for the upgrade to be completed in the Third Access Arrangement Period is $49.57 million.

The aim of the remaining upgrade work is to replace the existing four Saturn units with two larger Centaur compressors utilising current technology. The Saturn units are near the end of their useful life and by 2009 will be aged 27 (2 units) and 30 (2 units) years. Section 4.2 of the Compressor Strategy outlines the proposed refurbishment capital expenditure and sets out the merits for the upgrades and station redevelopment. In particular, the upgrade of the existing assets will replace the current wet-seal compressors with dry-seal units in accordance with the directive of Energy Safe Victoria (as noted above) to prevent injections of oil into the Pipeline.

The planned redevelopment also requires the removal of one of the existing Centaur units to a new location on the site, and demolition of the existing building structure to make space for additional pipeline systems anticipated in the near term. This is planned to be completed in 2011. The VENCorp report Vision 2030 identified the need for at least two additional pipeline systems to be terminated at the Brooklyn site in line with future growth of the PTS.

The redevelopment will result in slightly higher performance from the larger Centaur unit in compression into the Ballarat pipeline. This will provide an ancillary benefit in delaying the duplication of the Sunbury loop from 2009 to 2012 and possibly other augmentations in the future. The redevelopment from the current station set-up will also enable compression into multiple geographic regions (including the Corio, Ballan or South West Pipelines).

<u>Wollert compressor station</u>

As discussed in section 7.5.1 above, the Northern Zone augmentation comprises refurbishment capital expenditure in relation to the upgrade of the Wollert compressor station. Given the age of the Wollert assets (which were constructed in 1981), the compressor station would require significant redevelopment during the Third Access Arrangement Period. However, since a substantial augmentation of the station is required in 2009 to increase supply to the Northern zones, GasNet has developed an optimal (least cost) solution which entails replacing the three existing Saturn compressor units with two larger Centaur units for winter 2009. The Centaur units will replace the capacity of the existing Saturn units and provide the additional capacity required for the augmentation. The forecast cost for the redevelopment is $39.56 million (which is classified above as part of the Northern Zone augmentation expenditure).

Section 4.5 of the Compressor Strategy outlines the required capital expenditure and sets out the merits for the upgrades and station redevelopment. The redevelopment also addresses the requirement to replace wet-seal compressors in order to prevent injections of oil into the pipeline in accordance with the directive of Energy Safe Victoria (as noted in section 7.6.6).

In addition to the redevelopment described above, additional expenditure of $1.58 million is required for a fuel gas system to meet the requirements of the engine manufacturer.

7.6.7 Other compressor station upgrades

Further upgrades are required at the Iona and Gooding compressor stations at a cost of $2.96 million.

The work at Gooding includes an overhaul of one of the compressor units, plus a fire suppression system, estimated to cost $0.99 million.

Work at the Iona compressor station comprises a fire suppression system at a cost of $0.30 million and upgrade of the existing control system at the Iona compression station prior to the end of its operational life in 2012. The forecast cost for the control system is $1.62 million.

While compressor stations have a design life of about 25 to 30 years, control equipment at compressor stations has a relatively limited life (about 10 years). This is due to the greater demands on control capability and reliability of the stations and lack of support from suppliers.

8 Other capital elements

8.1 Code requirements

In addition to the roll-forward of the Capital Base, the Code requires the following supplementary components to be included as part of the determination of the Total Revenue:

(a) depreciation of the Capital Base (section 8.4(b) of the Code); and

(b) inflation (section 8.5A of the Code provides that the Building Block Methodology must be applied on a basis that deals with the effects of inflation).

8.2 Depreciation

8.2.1 Code requirements

Under the Building Block Methodology proposed by GasNet, depreciation of the Capital Base over the Third Access Arrangement Period represents one element of the costs used in establishing Reference Tariffs. Sections 8.32 and 8.33 of the Code set out the principles for calculating depreciation. In particular, the Depreciation Schedule should be designed:

(a) to result in the Reference Tariff changing over time consistently with the efficient growth of the market for the service provided;

(b) so that depreciation occurs over the economic life of the assets with progressive adjustments to reflect changes in the expected economic life of the assets; and

(c) subject to the capital redundancy provisions (section 8.27 of the Code), so that an asset is to be depreciated only once so that the total accumulated depreciation of an asset will not exceed the value of the asset at the time the asset was first incorporated into the asset base as adjusted for inflation.

8.2.2 GasNet's proposals

GasNet has continued to determine depreciation allowances using a real straight line profile over the remaining economic life of assets for the Third Access Arrangement Period.

GasNet proposes to retain the same technical and economic lives approved at the commencement of the Second Access Arrangement Period, with only minor modifications, discussed below.

Technical Life

The Technical Life of each asset class is shown in Table 8.1 below.

Table 8.1: Asset categories and technical life

Asset category	Technical life
Compressor stations	30 years
Heaters	20 years
Regulators	30 years
Pipelines	60 years
Telemetry equipment	10 years
Buildings	60 years
Land	N/A
Office equipment	5 years

The only change to this table from the current arrangements is the extension of the life of telemetry equipment from 5 to 10 years, made in the light of operational experience.

Economic Life

The economic life of each asset category generally follows the technical life, with the exception of the pipeline groups.

For the Second Access Arrangement, the Regulator accepted the analysis of Saturn Resources (attached to the Second Access Arrangement Submission) that the economic lives of Pipelines should be slightly shorter than the technical life, to account a range of factors including gas reserves risks, bypass risks, forced relocations and unexpected or unspecified factors.

A principal recommendation was to limit the economic life of the Longford pipeline to 2023 to reflect the anticipated depletion of Bass Strait (the SWP is not similarly limited as it has on-going value in connecting Melbourne to the storage facility at Port Campbell).

GasNet believes that there is no new information to suggest that these life assumptions should be changed. While there has been a large increase in gas reserves in the Otway basin, the Saturn Resources analysis noted the high prospectivity of the basin and allowed for substantial new discoveries.

In line with the principles underlying the Saturn Resources analysis, GasNet proposes that all new pipelines be given an economic life of 55 years.

In addition, the life of the Murray Valley pipeline will be extended from its current life of 2033 to 2054, which is its full economic life.

The proposed economic lives of the Pipeline asset groups is shown in Table 8.2.

Table 8.2: Remaining Economic Life by Pipeline Group

Pipeline Group	End of Life
Longford	2023
SWP	2052
Rest of Existing System	2033
Murray Valley Pipeline	2054
New Pipelines	55 years after commissioning

South West Pipeline

An exception to the general rule for depreciation described above is the depreciation allowance for the SWP.

For the Second Access Arrangement Period, the Depreciation allowance for the SWP was reduced from the standard straight line amount and deferred in order to provide a realistic tariff while volumes on the pipeline were very low.

However, gas volumes are now significantly higher, and are forecast to increase over the Third Access Arrangement Period. Under these circumstances, it is not appropriate to maintain the deferral of Depreciation, and the standard straight line profile will be used going forward.

8.2.3 Depreciation Schedule

Table 8.3 shows the calculated Depreciation allowance for each class of asset and the total Depreciation allowance that has been included in the Total Revenue. As discussed in section 5.10.2, this is based on the existing CCA framework utilising a real Rate of Return to calculate revenue.

Table 8.3: Depreciation Allowance by Asset Category ($ nominal)

Asset Category	2008	2009	2010	2011	2012
Pipelines	$16.4	$17.9	$19.3	$20.6	$21.4
Compressors	$5.0	$7.2	$9.1	$9.5	$10.7
System control facilities	$1.3	$1.6	$1.7	$1.8	$1.8
Odorisation	$0.0	$0.0	$0.0	$0.0	$0.0
Gas Quality	$0.1	$0.1	$0.1	$0.1	$0.2
General land and building	$0.4	$0.5	$0.6	$0.6	$0.6
Other	$0.8	$0.9	$0.9	$0.6	$0.6
Total	**$23.9**	**$28.3**	**$31.7**	**$33.3**	**$35.3**

8.3 Inflation

Consistent with section 8.5A of the Code, the Reference Tariffs have been calculated so as to deal with the effects of inflation. As GasNet has adopted a real Rate of Return methodology, the Reference Tariffs incorporate an escalation of the Capital Base each year, taking into account Depreciation in the preceding year. Consistent with the Second Access Arrangement, GasNet proposes to use the inflation forecast used for the WACC calculation (see section 6.6 above). Accordingly, GasNet has applied an annual inflation rate of 3.09%.[36]

[36] The action inflation forecast used of the Third Access Arrangement Period will be determined on a date close to the Final Decision (see section 6.6 of this Submission).

9 Non Capital Costs

9.1 Code requirements

The Code (sections 8.36 and 8.37) allows the recovery of all operating, maintenance and other non capital costs that would be incurred by a prudent Service Provider, acting efficiently and in accordance with good industry practice, in providing the Reference Service.

Attachment A to the Code requires the Service Provider to disclose certain costs in the AA Information, unless it would be unduly harmful to the legitimate business interests of the Service Provider

9.2 GasNet's proposal

GasNet's proposed Non Capital Costs are summarised in Table 9.1 below.

Table 9.1: Total Forecast Non Capital Costs 2008-2012 ($m 2006 (June))

	2008	2009	2010	2011	2012
$2006 (Jun) Base Forecast	20.93	20.93	20.93	20.93	20.93
Scope Changes	1.51	1.96	2.29	2.63	2.98
Workload Changes (excluding fuel gas)	0.74	1.47	1.73	2.14	2.62
Workload Changes Fuel Gas	1.35	1.50	1.58	1.65	1.80
SUB-TOTAL	**24.53**	**25.85**	**26.53**	**27.35**	**28.33**
Benefit Sharing Allowance	0.90	-0.69	-1.59	-0.85	0.00
Reset Costs	0.95				
K factor carry over[(a)]	0.91				
Asymmetric Risk	0.18	0.18	0.18	0.18	0.18
Equity Raising Costs	0.44	0.50	0.60	0.63	0.61
Other Allowances	0.19	0.19	0.19	0.19	0.19
TOTAL NON CAPITAL COSTS	**28.10**	**26.04**	**25.92**	**27.50**	**29.30**

(a) KTb_t 2006 only. KTa_t for 2007 will be estimated closer to the final decision.

Each category of forecast Non Capital Costs is discussed below. GasNet submits that these costs do not exceed the level of an efficient and prudent Service Provider acting in accordance with accepted and good industry practice.

9.3 Operating costs

9.3.1 Review of historical operating costs

Operating costs are the payments that provide for the operation and maintenance of the regulated GasNet system, the PTS.

The largest part of the operating cost budget for GasNet is internal labour. GasNet employs approximately 100 staff to provide the skilled services required in operating and maintaining the PTS and to provide various supporting administrative and general corporate functions attributable to the PTS. A full description of the activities comprising GasNet's operating costs was included in GasNet's Submission on the Second Access Arrangement.

As GasNet operates both regulated and unregulated businesses, GasNet's operating costs for the Second Access Arrangement Period were allocated between the regulated and unregulated businesses in accordance with the allocation principles approved by the Regulator as part of its 2002 Final Decision.

Table 9.2 shows GasNet's actual historical operating costs from 2003 to 2006, broken down into the main categories of:

(a) direct operating costs (including pipeline and compressor maintenance);

(b) fuel gas costs; and

(c) corporate overheads.

Table 9.2: Historical Operating Costs 2003-2006 ($m 2006 (June))

	2003	2004	2005	2006
Direct Opex	9.06	9.34	10.35	11.56
Fuel Gas	1.27	3.85	1.82	1.38
Corp O/H	8.18	7.92	7.64	8.14
TOTAL	**18.51**	**21.11**	**19.81**	**21.08**

Table 9.3 shows GasNet's original forecast operating costs for the Second Access Arrangement Period adjusted in accordance with the Fixed Principle set out in section 7.2(f) of the Second Access Arrangement.

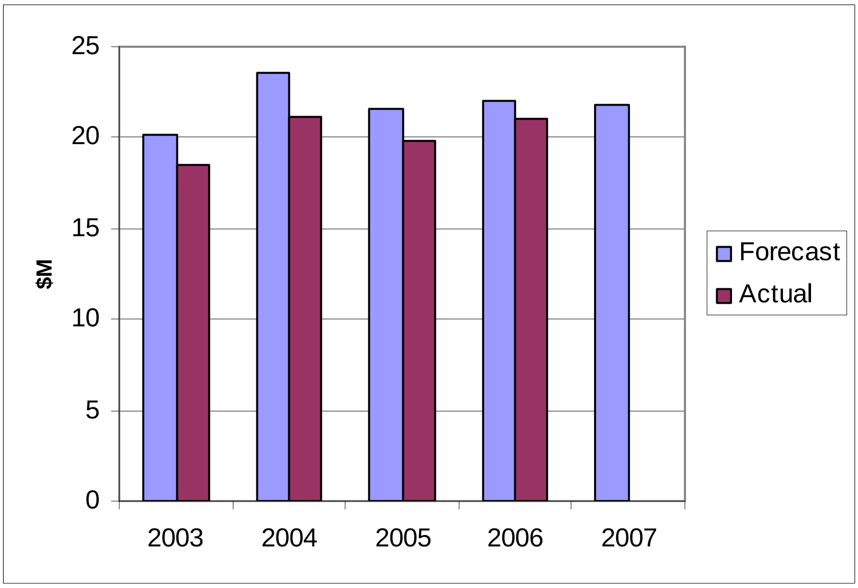
Table 9.3: Adjusted Forecast Operating Costs 2003-2007 ($m 2006 (June))

	2003	2004	2005	2006	2007
Direct Opex	10.15	11.17	10.31	11.46	11.22
Fuel Gas	1.43	3.83	2.76	1.76	1.86
Corp O/H	8.52	8.60	8.49	8.76	8.76
TOTAL	**20.10**	**23.60**	**21.56**	**21.98**	**21.83**

9.3.2 Historical cost trends

A comparison of the data set out in Tables 9.2 and 9.3 is set out in Figure 9.1.

Figure 9.1: Total Historical and Adjusted Forecast Operating Costs 2003-2007 ($m 2006 (June))



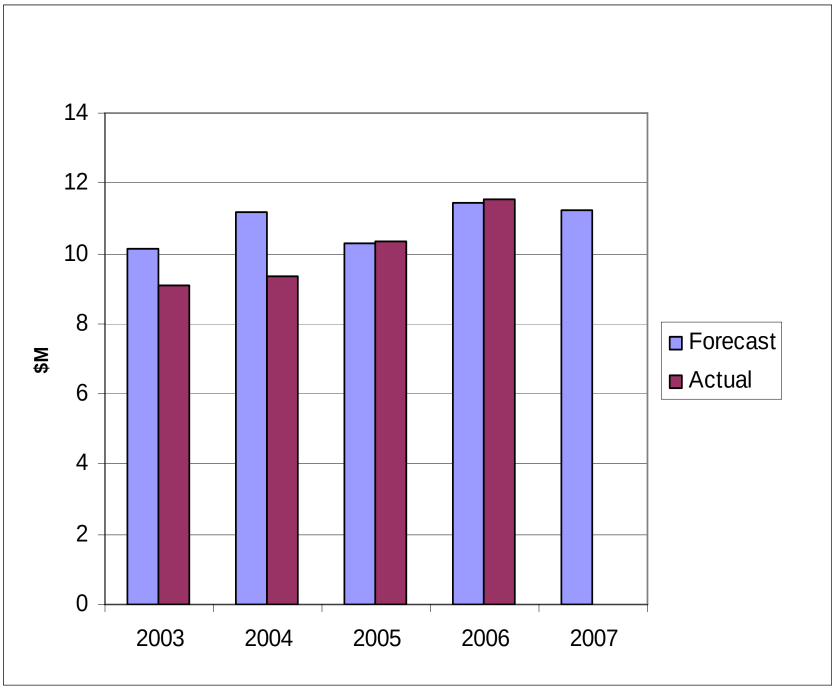
This comparison, and the data in Tables 9.2 and 9.3, illustrate that GasNet's historical operating costs for 2003 to 2006 were on average 7.7% lower than the original forecast operating costs approved in 2002 as adjusted in accordance with section 7.2(f) of the Second Access Arrangement.

In other words, the comparison supports a conclusion that over the Second Access Arrangement Period, GasNet has been operating at a more efficient level than that forecast for the period. However, the overall patterns in the summary data conceal important trends in certain cost categories where GasNet has experienced significant increases in its costs. These trends are illustrated further below and have been taken into consideration in determining forecast operating costs for the Third Access Arrangement Period.

Direct operating costs

Figure 9.2 shows a comparison between GasNet's historical direct operating costs and its adjusted forecast direct operating costs. The data shows that on average GasNet's historical direct operating costs have been lower than the adjusted forecast direct operating costs, but that the actual costs have been increasing over time.

Figure 9.2: Historical and Adjusted Forecast Direct Operating Costs 2003-2007 ($m 2006 (June))



GasNet submits that the increase in actual direct operating costs reflects a number of factors during this period, including:

(a) a higher demand for skilled labour in the gas industry;

(b) the cost of acquiring and training staff in a highly skilled but relatively narrow sector of the gas industry;

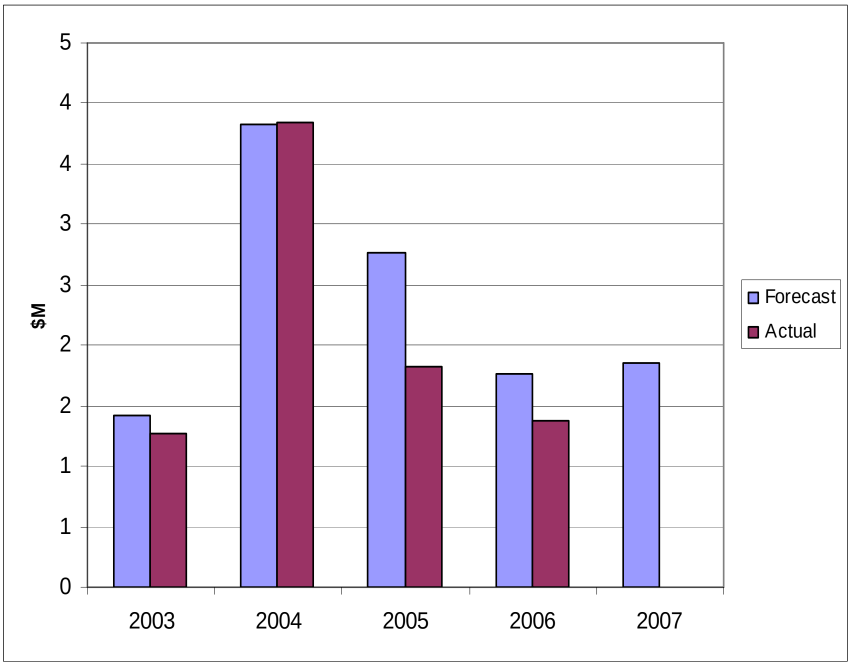
(c) the aging of the assets comprising the PTS; and

(d) the increasing standards of safety and technical regulation.

Fuel gas costs

Figure 9.3 shows a comparison between GasNet's historical fuel gas costs and its adjusted forecast fuel gas costs. GasNet's actual gas use from 2002 to the end of 2006 is shown later in Figure 9.6.

Figure 9.3: Historical and Adjusted Forecast Fuel Gas Costs 2003-2007 ($m 2006 (June))

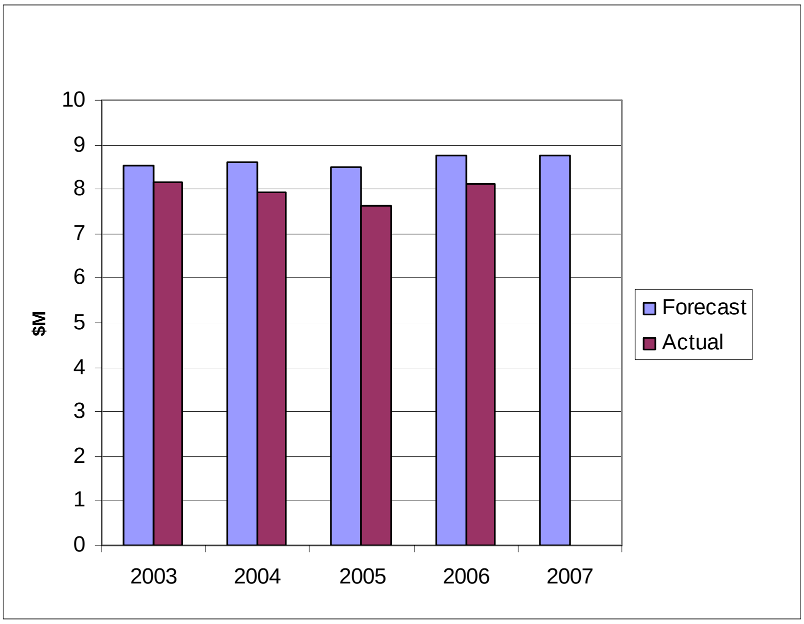


Exogenous factors (such as the very high fuel use required for unanticipated SEAGas exports in 2004), make it difficult to discern any exact trend in fuel gas costs over the Second Access Arrangement Period. Fuel use is also subject to other random exogenous factors such as weather and the growth of gas demand against the forecast.

<u>Corporate Overheads</u>

Figure 9.4 shows a comparison between GasNet's historical corporate overheads and its adjusted forecast corporate overheads. Overall, this data shows a decrease of 7.2% over the Second Access Arrangement Period. However, GasNet submits that the data does not show any significant or sustainable trend in corporate overheads suggestive of ongoing productivity changes or exogenous factors.

Figure 9.4: Historical and Adjusted Forecast Corporate Overheads 2003-2007 ($m 2006 (June))



9.3.3 *Forecast of operating costs - Fixed Principle*

Clause 7.2 of the Second Access Arrangement sets out a Fixed Principle which specifies in detail the procedure for calculating the benefit sharing allowance for 2008 to 2012. This is discussed in further detail in section 9.5.

In addition, and related to the forecasting of operating costs, clause 7.2(h) of the current Access Arrangement provides:

> *In calculating the allowable revenues for operations and maintenance expenditure for the Third Access Arrangement Period, the Commission must:*
>
> *(i) comply with the requirements of the Code;*
>
> *(ii) take into account the actual operating costs in 2006, adjusted for the change in forecast operating costs between 2006 and 2007 and, to avoid doubt, not taking into account the efficiency gain (loss) made in 2007;*
>
> *(iii) take into account forecast changes in workload, taxes, regulatory events, insurance premiums and other relevant costs between 2006 and each year of the Third Access Arrangement Period; and*
>
> *(iv) take into account a percentage trend factor.*

The requirements of the Code are set out above in section 9.1 of this Submission. The other elements of section 7.2(h) are discussed below.

9.3.4 *Calculation of Base operating costs*

Application of the Fixed Principle

Consistent with what is contemplated by clause 7.2(h)(ii) of the Second Access Arrangement, GasNet proposes to use the actual operating costs incurred in 2006 (as set out in Table 9.1) as the base for the setting of the forecast operating costs for the Third Access Arrangement Period ("**Base Operating Costs**").

GasNet submits that this is appropriate not only because it is contemplated by clause 7.2(h)(ii), but also because, in the context of an incentive-based regulatory regime, the latest actual cost must represent the best estimate of efficient costs going forward. This is supported by the following:

(a) the actual incurred costs in any particular year reveal GasNet's true efficient costs. Higher operating costs in any year come straight off the bottom line of GasNet's financial performance. Accordingly, GasNet has a strong profit incentive to minimise its costs to the most efficient level consistent with sustainable operations;

(b) the benefit sharing allowance acts in such a way that it provides an equal incentive on GasNet to make efficiency gains in each year, and no incentive to back-end costs; and

(c) in any event, use of 2006 actuals has been accepted previously by the Regulator as an appropriate starting point.

Relevance of post-2006 actuals

GasNet submits that changes in actual costs post-2006 are an irrelevant consideration for the purpose of forecasting operating costs for the Third Access Arrangement Period.

For the purposes of this Third Access Arrangement Period, the only *demonstrable* costs upon which a forecast can be based are those actually incurred by GasNet up to the end of 2006. Adjustments based on 2007 actuals are not possible given this data is not yet known, but even if the 2007 actual cost was known or could be reasonably estimated, it would not be appropriate to take it into account.

The reason adjustments for 2007 actuals are not appropriate is because any cost improvements in 2007 (for example, resulting from any restructure of all of the APA Group's operations including GasNet) would in principle be kept by GasNet for the five years of the new Access Arrangement Period through the operation of the benefit sharing allowance. That is, if costs decline to reveal a lower efficient cost in 2007, then GasNet would be entitled to keep this efficiency gain for the subsequent five years, after which the benefit would be passed on to end Users.

While GasNet appreciates that in time there may be an argument to suggest that certain synergies may result from the sharing of certain general direct and corporate functions resulting from the APA Group proposed restructure, at this stage it is impossible to anticipate what the result of the restructure may be and therefore whether in fact any restructure will result in higher or lower costs. In any event, any resulting synergies from the APA Group relationship will be realised:

(a) via the application of the benefit sharing allowance; and

(b) eventually, through the use of actuals in calculating the forecasting operating costs for the Fourth Access Arrangement Period.

Calculation of Base operating costs

As contemplated by the Fixed Principle, GasNet has also made adjustments to the Base Operating Costs for changes in forecast operating costs between 2006 and 2007. Table 9.4 sets out GasNet's calculation of the Base Operating Costs in accordance with clause 7.2(h)(ii) of the Fixed Principle.

Table 9.4: Base Opex Forecast ($m 2006 (June))

2006 actual operating costs[(a)]	21.08
Forecast Change 2006 to 2007	-0.15
Base Opex Forecast	20.93

(a) Excludes reset costs

9.3.5 *Forecast of operating costs*

In accordance with clause 7.2(h)(iii) of the Fixed Principle, in calculating its forecasting operating costs, GasNet has taken into account forecast changes in workload, taxes, regulatory events, insurance premiums and other relevant costs between 2006 and each year of the Third Access Arrangement Period. GasNet anticipates that:

(a) forecast workload changes will have an impact on direct operating costs and fuel gas costs going forward; and

(b) forecast scope changes will have an impact on direct operating costs and corporate overheads.

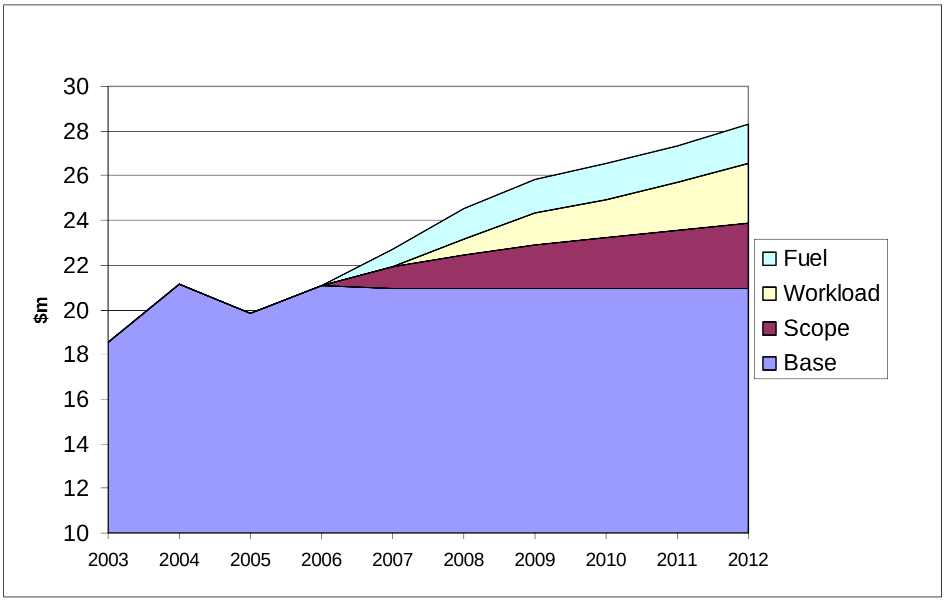
A summary of these changes is set out in Table 9.5. Further detail is provided below.

Table 9.5: Total Forecast Operating Costs, Jan 2008- Dec 2012 ($m 2006 (June))

	2008	2009	2010	2011	2012
Base Opex Forecast	20.93	20.93	20.93	20.93	20.93
Scope changes	1.51	1.96	2.29	2.63	2.98
Workload changes (including fuel gas)	2.09	2.97	3.31	3.79	4.42
Forecast Reset cost	0.95				
Total Opex	**25.48**	**25.86**	**26.53**	**27.35**	**28.33**

In addition, Figure 9.5 compares GasNet's actual and forecast operating costs from the start of the Second Access Arrangement Period to the end of the Third Access Arrangement Period - including the impact of the scope and workload changes.

Figure 9.5: GasNet Actual and Forecast Operating Costs 2003 - 2012 ($m 2006 (June))



9.3.6 *Forecast scope changes*

Changes in the scope of activities required to be undertaken by a regulated business will impact on the forecast of direct operating costs and corporate overheads.

The anticipated scope changes for direct operating costs are largely driven by technical and safety regulation, by new legislated requirements, and by exogenous economy wide factors and include:

(a) increases in the cost of labour;

(b) reviewing and updating of existing policies and procedures to ensure that they comply with the recent and proposed changes to health and safety legislation and the Australian Standard (AS) 2885;

(c) updating of policies and procedures for new assets installed during the Third Access Arrangement Period;

(d) security upgrades of key facilities and pipelines resulting from the Terrorism Act;

(e) measures to counteract the effect of an aging workforce and labour shortage issues;

(f) GasNet's obligations under the Service Envelope Agreement.

The scope changes impacting on forecast corporate overheads include:

(a) anticipated IT cost increases attributable to the PTS and establishment of a disaster recovery site;

(b) costs associated with a regulatory accountant and compliance function attributable to GasNet; and

(c) anticipated increases in the cost of labour.

Table 9.6 sets out GasNet's anticipated scope changes for the Third Access Arrangement Period. Further details are set out in Attachment D (Scope and Workload Changes Report) to this Submission.

Table 9.6: Forecast scope change ($m 2006 (June))

	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Direct Opex[(a)]	0.48	0.58	0.71	0.71	0.71	0.72
Overheads[(a)]	0.31	0.31	0.31	0.31	0.31	0.31
Labour (direct and overheads)	0.30	0.62	0.94	1.26	1.60	1.95

(a) Excluding labour costs

9.3.7 *Workload changes - direct operating costs*

During the Third Access Arrangement Period, GasNet is forecasting a significant increase in the length of pipelines as a result of the construction of a number of new pipeline loopings, including the Brooklyn Lara (Corio) pipeline (see section 7.5.8 of this Submission).

Similarly, in respect of the forecast compressor operating costs, the increase in compressor capacity of the PTS (see sections 5.8, 7.5 and 7.6 of this

Submission) will also lead to an increase in compressor operating costs. In particular, the forecast includes a prudent allowance for the following workload changes:

(a) an increase in the compressor capacity, including unit upgrades at Wollert and Brooklyn, and new compressor Stations at Euroa and Stonehaven during the Third Access Arrangement Period (see section 7.3.1 for further details) - the replacement cost of compressors is forecast to increase from $157.3 million in 2007 to $200.4 million in 2012; and

(b) additional in-line regulators and heaters, including new or upgraded or substantially upgraded regulators, and new heaters at Dandenong, Wollert, Lara, Brooklyn, Wandong, Clonbinane, North Laverton and Morwell - the replacement cost of regulators and heaters will increase from $33.2 million in 2007 to $45.6 million in 2012.

These workload changes will result in increased direct operating costs and fuel gas costs. Table 9.7 sets out GasNet's anticipated workload changes for the Third Access Arrangement Period. Further details are set out in Attachment D (Scope and Workload Changes Report), and, in relation to the increased fuel gas costs, section 9.3.8.

Table 9.7: Direct operating cost workload change forecasts ($m 2006 (June))

	2008	2009	2010	2011	2012
Pipelines	0.16	0.21	0.41	0.41	0.45
Compressors / Regulators	0.58	1.26	1.32	1.73	2.16
Fuel gas workload change	1.35	1.50	1.58	1.65	1.80

9.3.8 Workload changes - fuel gas costs

GasNet must provide gas for compressor and heater operations and must purchase this at market rates. As with the Second Access Arrangement Period, VENCorp controls the operation of the compressors, which are scheduled on the basis of demand. GasNet has utilised its system planning models to analyse the system requirements going forward based on the anticipated utilisation of the existing and planned compressor and heater facilities.

Figure 9.6 shows the historical actual and forecast fuel gas usage.[37] The associated total fuel costs (forecast only) are shown in Table 9.8. A detailed report has been provided to the Regulator separately.

[37] This forecast is based on the forecast injection and withdrawal volumes described in section 10.2.2 of this Submission.

Figure 9.6: Total Historical (up to end of 2006) and Forecast Fuel Gas Usage (TJ)

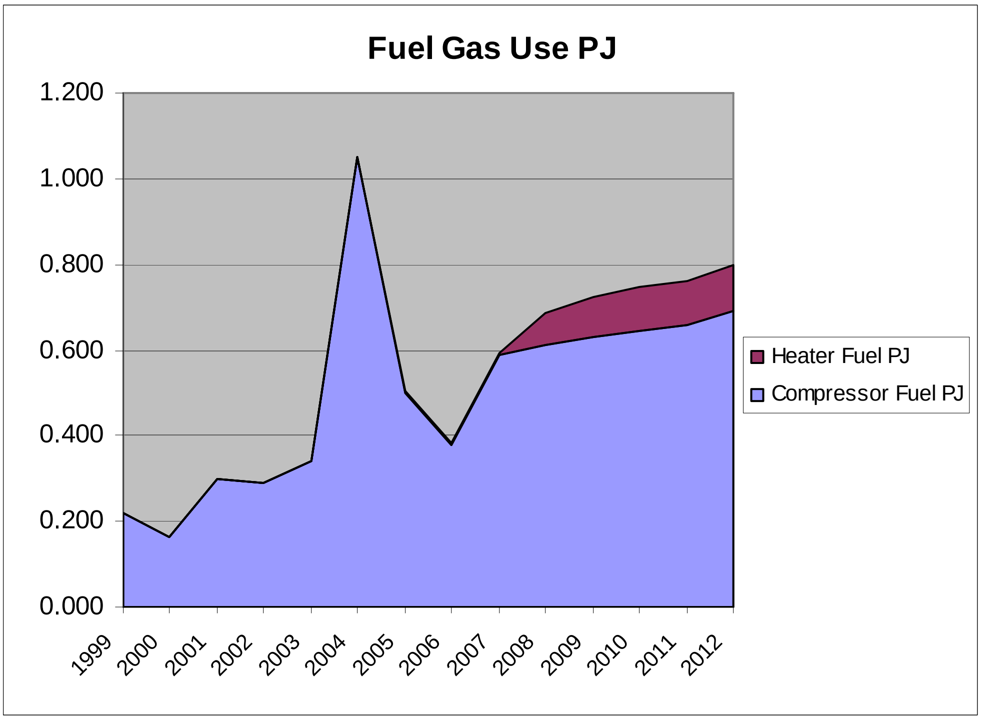


Table 9.8: Total Fuel Gas Forecast ($m 2006 (June))

2007	2008	2009	2010	2011	2012
2.20	2.73	2.88	2.97	3.04	3.18

Additional heating will be required in the Third Access Arrangement Period because forecast growth in injection volumes and new injection sources (such as Yolla and Otways gas) mean that the PTS must have the facilities in place to handle higher components in the gas stream and higher linepack and system pressures.

The requirement for gas heating facilities arises from the fact that when gas pressures are reduced at a regulator station, there is an associated fall in gas temperature which can have negative effects on downstream assets. For example:

(a) ice can form on control equipment leading to operational failures;

(b) hydrates could form in the pipeline system; or

(c) gas liquids can form in the gas stream if the gas composition contains higher components (e.g. propane).

Depending on the gas composition and the extent of the pressure drop, it may be necessary to pre-heat the gas to avoid these harmful effects.

The Gas Safety Regulations stipulate a minimum temperature standard for gas conveyed in a transmission pipeline of 2°C.[38] GasNet's capital expenditure and operating cost forecasts for heaters and heater fuel use are designed to meet this standard.

Other factors taken into consideration in calculating forecast fuel gas costs include:

(a) the fact that GasNet's gas supply contract will be renegotiated in 2008. An allowance for a price increase of up to 10% has been made given the fact that gas prices during peak periods have been rising at faster than average rates (and compressor fuel is principally required during the peak periods); and

(b) an allowance of gas to provide for refill of underground storage and for gas exports, derived from GasNet's knowledge of system dynamics and observation of the compressor stations under a variety of conditions. It is also based on the export and refill forecasts set out in section 4 of the AA Information.

9.3.9 Productivity changes

Clause 7.2(h)(iv) of the Second Access Arrangement contemplates that in forecasting its operating costs for the Third Access Arrangement Period, GasNet has taken into account a percentage trend factor.

While GasNet understands that the intention of this element was in order to reflect any decrease in costs across the industry generally, GasNet submits that the antithesis is true for the gas industry.

The historical data and historical trends discussed in sections 9.3.1 and 9.3.2 above demonstrate that GasNet's direct operating costs (excluding fuel gas costs) have increased at a real rate of 4.5% per annum from 2003 to 2006. GasNet submits that there is no reason to believe that this rate of increase will change in the future, let alone that costs will decrease.

On the contrary, anticipated changes in GasNet's scope of activities, workload changes and other relevant costs support the argument that GasNet's operating costs are going to continue to increase during the course of the Third Access Arrangement Period. GasNet submits that GasNet's historical cost data and historical trends are actually evidence of the fact that:

(a) the majority of all productivity gains to be made as a result of the privatisation of GasNet have been exhausted; and

(b) the gas industry is now facing a period of rising costs.

[38] Gas Safety (Gas Quality) Regulations 1999, Schedule 1.

9.4 K factor carry over

GasNet's current Access Arrangement contains a Fixed Principle which provides that GasNet can recover an amount for the K factor carry over in the Third Access Arrangement. In particular, clause 7.1 of the Second Access Arrangement provides:

> *The Regulator must include in the Reference Tariffs for the Third Access Arrangement Period:*
>
> *(a) an allowance for KTa_t (as defined in Schedule 4) relating to 2007 as if Schedule 4 continued to apply in the Third Access Arrangement Period;*
>
> *(b) an allowance for KTb_t (as defined in Schedule 4) relating to each of 2006 and 2007 as if Schedule 4 continued to apply in the Third Access Arrangement Period.*
>
> *These allowances must be based on actual figures (or estimates where actual figures are not available).*

GasNet has maintained an account representing the K factor and submitted this to the Regulator each year as part of its annual tariff approval process.

The K factor which is to be rolled forward into 2008 under the revenue control model is not currently known. In particular:

(a) KTa_t for 2007 cannot be calculated until late October 2007 when the peak Injection Charges for 2007 are calculated. However, an estimate can be made at any time based on the relationship of the forecast monthly average Withdrawal Tariff to the actual monthly Withdrawal Tariff. The closer to October 2007 the estimate is made, the more accurate it will be (and any estimate provided before winter is unlikely to be indicative of the likely KTa_t for 2007); and

(b) KTb_t for 2007 cannot be calculated until March 2008.

GasNet therefore proposes that the following allowances be included in the Third Access Arrangement Period:

(a) \$909,000 for KTb_t for 2006 (based on actual figures); and

(b) an amount for KTa_t for 2007 estimated based on the latest monthly data available on a date prior to the Regulator's final decision agreed between GasNet and the Regulator - GasNet suggests that the same date that the risk free interest rate and inflation forecasts are finalised would be the most appropriate.

Any discrepancy between the actual and forecast K factor for 2007 (KTb_t) will be added to the K factor calculated for the year 2008 under the proposed new revenue control model for the Third Access Arrangement Period (see Schedule 4 of the draft Access Arrangement).

GasNet proposes to add the forecast K factor carry forward to the forecast operating costs as an extraordinary expense applying at 1 January 2008.

9.5 Application of benefit sharing allowance

Clause 7.2(a) of the Second Access Arrangement provides that in each of the first five years after 2007, the Reference Tariffs must be determined in a manner that includes a benefit sharing allowance calculated in accordance with clause 7.2 of the Second Access Arrangement.

The intent of the allowance is to provide an incentive for GasNet to reduce operating costs and increase efficiency in a sustainable way. It does this by allowing the gain (loss) from any reduction (increase) in costs to be kept by GasNet for the next five years, including those years that extend into the next Access Arrangement Period.[39]

The calculation is performed in the following steps. Table 9.1 shows the benefit sharing allowance for each of years 2008-2011.

Step 1 - clause 7.2 (f) and (g)

GasNet has adjusted forecast operating costs for Pass Through Amounts and transmission refill tariff amounts and reduced the amount to June 2002 dollars as shown in Table 9.9. An inflation rate of 2.16% has been used. There have been no Expansions of the PTS during the Second Access Arrangement Period and only one small Extension being a 2.7 km small diameter lateral pipeline. Accordingly, the incremental operating and maintenance costs have been negligible.

Table 9.9

	2003	2004	2005	2006
Forecast operating costs	18.20	19.95	19.51	21.21
Adjusted forecast operating costs ($m 2002 (June)	17.93	21.04	19.23	19.60

Step 2 - clause 7.2 (g)

GasNet has reduced actual operating costs for the years 2003-2006 to June 2002 dollars as shown in Table 9.10 using actual CPI as at June of the relevant year.

Table 9.10

	2003	2004	2005	2006
Actual operating costs	16.95	19.81	19.05	21.08
Adjusted actual operating costs ($m 2002 (June))	16.51	18.82	17.67	18.80

39 Although GasNet has included efficiency losses incurred in the Second Access Arrangement Period in the draft Access Arrangement, it has proposed changes to the benefit sharing mechanism (see section 11.9.3).

Step 3 - clause 7.2 (c) and (d)

The efficiency gains (losses) (E_t) for each year are included in Table 9.11.

Table 9.11

	2003	2004	2005	2006
Efficiency Gain ($m 2002 (June))	1.42	0.8	-0.66	-0.76

Step 4 - clause 7.2 (b)

In Table 9.12 GasNet has calculated the benefit sharing allowances (B_t except that it is in $m 2002 (June) dollars) applicable to years 2008 to 2011.

Table 9.12

Year	B_t	Amount
2008	$E_{2003} + E_{2004} + E_{2005} + E_{2006}$	0.80
2009	$E_{2004} + E_{2005} + E_{2006}$	-0.61
2010	$E_{2005} + E_{2006}$	-1.41
2011	E_{2006}	-0.76

Step 5 - clause 7.2 (b)

In Table 9.13 GasNet has converted the benefit sharing allowances to 2006 dollars.[40]

Table 9.13

	2008	2009	2010	2011
$2002 B_t	0.80	-0.61	-1.41	-0.76
$2006 B_t	0.90	-0.69	-1.59	-0.85

9.6 Asymmetric risks

Consistent with the approach taken in the Second Access Arrangement Period, GasNet proposes to include an allowance in the Third Access Arrangement Period for a number of asymmetric risks that are not adequately reflected elsewhere in the Total Revenue calculation.

GasNet has engaged SAHA International to undertake a valuation of the risk GasNet is proposing to self-insure for (see Attachment E of this submission).

40 The actual forecast for inflation to be used for the Third Access Arrangement Period will be calculated on a date close to the Final Decision (see section 6.6 above).

Table 9.14 below details each category of asymmetric risk and the allowance sought for the Third Access Arrangement.

Table 9.14: Categories of Asymmetric risk ($ nominal)

Asymmetric Risk	Allowance ($p.a.)
Uplift Liability	$65,000
Key person risk	$37,500
Employment practices risk[(a)]	$32,000
Insurer's credit risk	$1,600
Bomb threat and extortion	$1,400
Fraud risk	$52,000
Total	**$189,500**

(a) SAHA International refers to "employment practices risk" as "Human Resources risk" however GasNet has maintained the terminology used for the Second Access Arrangement Period.

Consistent with its submissions on the Second Access Arrangement, GasNet accepts that specific risks should not be reflected in the Rate of Return calculated using CAPM. However GasNet submits that there are a number of specific risks that should be reflected in the Reference Tariffs. As set out in GasNet's Second Access Arrangement submissions, the key characteristics of these "allowable" risks are that:

(a) they are asymmetric (i.e. the possible negative outcomes are significantly larger than the possible positive outcomes);

(b) they are difficult (if not impossible) to insure against at commercial rates;

(c) they cannot be diversified away by investors because the counterparties to these risks are not public companies in which investors can invest; and

(d) taken together, they produce the result that the likely economic income that GasNet expects relating to the Reference Tariffs is less than the target economic income that is used to determine the Reference Tariffs (i.e. the Total Revenue).

Apart from the allowance for "fraud risk", the categories of asymmetric risk are the same, and the amount of the allowances proposed are either similar or less then, the categories or amounts allowed for the Second Access Arrangement.

GasNet included detailed submission on these asymmetric risks in its submissions in relation to the Second Access Arrangement (see in particular Schedule 4). The SAHA International report also supports the allowances sought, including GasNet's proposal to self-insure for fraud risk.

9.7 Equity raising costs

As GasNet submitted in relation to the Second Access Arrangement, raising capital is an integral part of any commercial organisation and the costs associated with raising both debt and equity represent a significant and necessary expense.

GasNet is proposing to include debt raising costs in the WACC (see section 6.7 of this Submission).

Consistent with the Second Access Arrangement, GasNet proposes to include in its Non Capital Costs an annual allowance of 0.224% per annum of regulated equity.

GasNet notes that when assessing GasNet's Second Access Arrangement, the Commission concluded that an allowance for equity raising costs was permitted by the Code.[41] This was because:

(a) they were costs which GasNet must pay when undertaking capital raising; and

(b) the Commission took the view that they had not been incorporated in GasNet's Capital Base.

At that time, the Commission acknowledged that there was an alternative view that the Initial Capital Base of a regulated entity incorporates all capital costs and therefore no additional payment is required for equity raising. However, it nevertheless concluded that it was appropriate to include equity raising costs in GasNet's Non Capital Costs because to do so better reflected the process used to determined the Capital Base for GasNet.

9.8 Other allowances (cost of maintaining linepack and inventories)

As with the Second Access Arrangement, GasNet proposes to include an allowance for Total Revenue to reflect the costs of:

(a) investment in passive linepack gas, including linepack required for the new loops (this gas is required in order to keep the pipeline pressurised and available for service); and

(b) inventories (i.e. the cost of holding spares and materials to deal with emergencies and standard maintenance activities).

These were included in GasNet's submissions on the Second Access Arrangement as an allowance for working capital. In its 2002 Final Decision, the Commission approved a return on these costs of $0.11 million per annum for 2003-2004 and $0.12 million for 2005-2007 on the basis that these are genuine costs which are not otherwise reflected or offset in the Reference Tariff.[42]

Table 9.15 shows the cost associated with each of these items and the forecast return on these other allowances for the period 2008 to 2012.

[41] ACCC GasNet 2002 Final Decision, at p149-150.

[42] Regulator Final Approval, at p10.

Table 9.15: Other allowances ($m 2006 (June))

	2008	2009	2010	2011	2012
Return on linepack	0.15	0.15	0.15	0.15	0.15
Return on inventories	0.04	0.04	0.04	0.04	0.04
Total	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**

10 Volumes and Calculation of Total Revenue

10.1 Calculation of Total Revenue

10.1.1 GasNet's proposal

GasNet's proposals in relation to each of the individual building block components that make up the Total Revenue requirement have been detailed in other parts of this Submission. Table 10.1 summarises each of these components.

Table 10.1: Summary of components of the Total Revenue requirement ($million (nominal))

Components of Total Revenue requirement	2008	2009	2010	2011	2012
Return on assets	$34.45	$41.23	$47.28	$49.39	$50.93
Depreciation	$23.94	$28.26	$31.73	$33.28	$35.29
Non Capital Costs	$29.09	$28.76	$29.40	$32.12	$35.29
TOTAL	**$87.47**	**$98.25**	**$108.41**	**$114.79**	**$121.51**

To create a smooth pricing path, GasNet proposes that tariffs in each year after the first year of the Third Access Arrangement Period should be escalated by the factor CPI-X. Consequently, forecast revenue calculated on the basis of tariffs multiplied by volumes will differ from the Revenue Requirement under the Building Block Methodology. The initial tariffs and the X value are set so that the NPV of the forecast revenue stream is the same as the NPV of the Revenue Requirement. The Revenue Requirement and forecast revenues (target revenue for the purposes of the price control model) for the five year Access Arrangement Period are set out in Table 10.2 below, based on the X-factor values in Schedule 1 of the draft Access Arrangement.

Table 10.2: Revenue Requirement and Target Revenue ($million (nominal))

Year ending 31 December	2008	2009	2010	2011	2012
Revenue requirement ($m)	$87.47	$98.25	$108.41	$114.79	$121.51
Forecast Revenue ($m)	$91.59	$98.35	$105.93	$112.79	$120.69

10.1.2 Current revenue calculation model

Each of the key inputs for determining the Total Revenue building blocks outlined above are calculated within a current cost accounting framework and have been set out elsewhere in this Submission.

However, there are a number of options for determining the value of the building blocks - in particular in relation to the timing of cost and revenue recognition.

The Total Revenue calculation model used to calculate revenues for the Second Access Arrangement Period ("**current revenue calculation model**") assumes (for the purposes of simplicity) that all revenue and cost quantities are determined at the end of each year in the Second Access Arrangement Period. In particular:

(a) the roll forward of the RAB for any Regulatory Year is determined as:

RAB (close) = RAB (open) * (1+i) - Depreciation + Capex * (1+ i/2)

where:

(i) i is the inflation rate over the year;

(ii) Depreciation is RAB (open) / Remaining Asset Life * (1+i) for each asset; and

(iii) Capex is deemed to be incurred in the middle of the year; and

(b) the return on assets is determined as:

RAB (open) * real WACC * (1+i)

There is no allowance for a return on capital expenditure in the year that the capital expenditure is incurred.

Capital expenditure is determined on an "as-commissioned" basis. That is, the capital expenditure is treated on a project by project basis, and each project is treated as a single payment at the date of commissioning, with interest during construction rolled-up into the total project cost.

10.1.3 Issues with application of current revenue calculation model to Third Access Arrangement Period

GasNet submits that the current revenue calculation model is inappropriate for the Third Access Arrangement Period as it will lead to a significant under-recovery of costs:

(a) due to the very large capital expenditure program proposed (as described in section 7 of this Submission); and

(b) exacerbated by the actual timing of GasNet's capital and refurbishment expenditure programs. Most of GasNet's capital expenditure in any Regulatory Year must be commissioned before the winter to enable the relevant facilities to be operated to meet the peak loads. Similarly, refurbishment expenditure must be completed before winter as the Facilities must be available for the peak period.

As a result, under the current revenue calculation model, GasNet would fail to earn any return on substantial capital and refurbishment expenditures between a commissioning date prior to winter and the end of the Regulatory Year in question.

GasNet has constructed a detailed monthly model of costs and revenues in order to assess the extent of under- or over-recovery of costs under the current revenue calculation model. The monthly or "exact" model uses monthly profiles of:

(a) revenue collection (noting the specific payments profile and invoicing dates);

(b) operating costs (including the dates for the payment of pipeline licence fees and insurance premiums);

(c) construction costs (with indicative forecast monthly profiles for pipelines, compressors, regulators, heaters and other assets).

The monthly model is determined over the five year Third Access Arrangement Period based on the proposed capital expenditure program described in section 7. The current revenue calculation model is calculated on the same parameters with an allowance made for interest during construction for each "as-commissioned" project in the capital expenditure program.

The "exact" model is then compared with the revenue results generated using the current revenue calculation model. The result of the comparison is that the current annual model produces a total present value of revenues that is 1.9% below the "exact" solution.

10.1.4 *Proposed revenue calculation model*

GasNet submits that for the reasons indicated in section 10.1.3 above, the revenue calculation model should include an allowance for a half-year's return on capital expenditure ("**proposed revenue calculation model**").

GasNet has assessed the proposed revenue calculation model against the "exact" model above. The results indicate that the proposed revenue calculation model may over-recover by a marginal 0.4%. Given that the actual profiles could differ from the assumptions in the "exact" model, GasNet submits that the proposed revenue calculation model is the best method for the purposes of this Access Arrangement.

The proposed revenue calculation model is similar to the model employed for the First Access Arrangement Period (i.e. 1999 - 2002), which included a half year return on capital expenditure on the basis that it was appropriate if capital expenditure was assumed to be spent mid-year (as was the simplifying assumption at the time).

GasNet is aware that in its 2002 Final Decision, the Commission rejected this approach, arguing that the revenue calculation model for the First Access Arrangement Period over compensated GasNet because (amongst other things) the model allowed the revenue to be determined at the end of the year when it was actually collected from tariffs during the year. However, GasNet notes that:

(a) no calculations were provided by the Commission at the time to demonstrate this; and

(b) for the reasons outlined in section 10.1.3 above, the proposed revenue calculation model is consistent with the Code principles set out in Section 8 of the Code.

A revenue model that recognises a half yearly return on capital is also consistent with the approach proposed by the AER for electricity transmission network service providers. In particular, the AER states[43]:

> "*… opex and revenue is assumed to take place on the last day of the year, while capex is assumed to take place throughout the year, which in practice is approximated by a half-WACC adjustment mid way through the year.*
>
> …
>
> *In contrast, capital expenditure is rolled into the RAB inclusive of a half WACC adjustment, which attempts to compensate businesses for the fact that capital expenditure is realistically more likely to occur throughout the year … rather than on the last day of the year.*"

GasNet has also considered whether it is appropriate to maintain the current "as-commissioned" approach[44] or to move to an "as-incurred" model. For the following reasons, GasNet has chosen to maintain the current "as-commissioned" approach:

(a) GasNet's capital expenditure is very lumpy from year to year;

(b) the projects engaged in are large relative to the RAB;

(c) GasNet prefers to seek approval on a project-by-project basis, rather than for an amorphous annual capital expenditure plan, as this leads to greater certainty; and

(d) typically projects do not exceed a three year timeframe, which is manageable within the five year Access Arrangement Period.

GasNet does not anticipate any large projects past the Third Access Arrangement Period which would require capital expenditure in 2011 or 2012. If such a project arose, GasNet would use the ex ante provisions of the Code to obtain regulatory certainty before making the required expenditures.

43 AER, *First Proposed Electricity Transmission Network Service Providers Post-Tax Revenue Model: Explanatory Statement and Issues Paper*, January 2007, p6.

44 This is the method adopted in both the First Access Arrangement Period and the Second Access Arrangement Period. This means that the capital expenditure is regarded as being incurred at the date of commissioning despite the fact that actual capital expenditure may be incurred over a period of up to 3 years for large pipeline and compressor projects. Under this approach, the Capital Base is only updated to include the capital expenditure in the year in which the asset is commissioned. Under an "as-incurred" approach, the Capital Base is updated each year for the amount of actual capital expenditure in that year regardless of when the asset is commissioned.

10.2 Forecast Volumes

10.2.1 Code requirements

Under section 8.4 of the Code, Total Revenue may be calculated on the basis of forecast volumes. In addition, sections 8.38 to 8.41 of the Code allow Reference Tariffs to be based on forecast volumes.

Section 8.2(e) of the Code requires that any forecasts used in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

Section 4 of the Access Arrangement Information contains summary information in relation to GasNet's volume forecasts. This section of the Submission is intended to provide an explanation of the assumptions underlying those forecasts.

10.2.2 Withdrawal volumes

For the purposes of the draft Access Arrangement, GasNet requires forecasts of the annual and peak day gas volumes withdrawn from the PTS. These forecasts are used for the setting of Transmission Tariffs, and for the calibration of the revenue control formula. The forecast annual withdrawal volumes for the Third Access Arrangement Period and the forecast peak day withdrawal volumes are set out in Tables 10.3 below.

Table 10.3: Annual Withdrawal Volumes Forecast 2008-2012

Injection Point	**2008**	**2009**	**2010**	**2011**	**2012**
Annual (PJ)					
VENCorp	219.2	219.6	220.7	221.8	224.1
less notional Compressor Fuel	-0.4	-0.4	-0.4	-0.4	-0.4
Culcairn export	2.5	3.8	5.0	5.0	5.0
VicHub export	0.3	0.3	0.3	0.3	0.3
Sub-Total	**221.7**	**223.3**	**225.7**	**226.7**	**229.0**
UGS/LNG Refill	0.8	0.8	0.8	0.8	0.8
Total	**222.5**	**224.1**	**226.5**	**227.6**	**229.9**
Peak (TJ/day)					
VENCorp	1168	1174	1183	1192	1205
less notional Compressor Fuel	-4	-4	-4	-4	-4
GPG	50	50	50	50	50
Culcairn export	17	17	17	17	17
VicHub export	1	1	1	1	1
UGS/LNG Refill	0	0	0	0	0
Total	**1,233**	**1,239**	**1,248**	**1,256**	**1,270**

For the majority of the gas demand, GasNet has elected to use the forecasts prepared by VENCorp as part of the VENCorp APR. VENCorp is required to prepare forecasts of gas demand and supply capabilities for a five year period. The VENCorp APR document provides forecasts of the general demand (that is, for the residential, industrial and commercial markets) and the demand in gas-fired power generators.

GasNet has supplemented these forecasts with its own estimates of:

(a) interstate gas exports;

(b) storage refill volumes; and

(c) peak day volumes associated with gas-fired power generators.

10.2.3 *Export Volumes*

Historically gas has been exported from the PTS at Culcairn, VicHub and at the SEAGas interconnection point.

Exports at VicHub have varied from 0.1 PJ/annum in 2004 to 1.2 PJ in 2005. GasNet is projecting indicative volumes of 0.3 PJ/annum going forward.

Exports at the SEAGas interconnection point have generally been negligible, with the exception of 2.4 PJ/annum in 2006. With the forecast increase in injection volumes from the Otways it is expected that SEAGas exports will in future be zero.

Culcairn exports have varied from 1.6 PJ/annum to 3.6 PJ/annum over the last five years. The export capacity is generally limited to 17 TJ/day in winter. However there is growing interest in exports through Culcairn, and it is anticipated that a gas-fired power generator will be operating at a location near Wagga Wagga by 2009, and sourced with gas from Victoria. In addition, a retailer is seeking to supply customers in country NSW. Therefore GasNet has projected an export volume of 2.5 PJ for 2008, 3.8 PJ in 2009 and 5.0 PJ/annum from 2010 onwards, being the available export capacity flowing at an 80% load factor.

10.2.4 *Storage Refill*

The underground storage facility at Port Campbell has a capacity of approximately 10 PJ. Flows into storage have been as high as 18.3 PJ/annum in 2004, but have since declined dramatically to 0.9 PJ/annum in 2006. It is our understanding that the 2004 flows were essentially exports to South Australia, required because of delays in commissioning of the Minerva gas processing plant.

Given that the storage can now be filled with gas taken directly from the adjacent offshore fields, it is expected that only minimal refill volumes will be taken from the PTS. GasNet is projecting volumes of 0.5 PJ/annum.

Refill of the LNG facility is usually between 0.1 and 0.3 PJ/annum. GasNet is projecting refill of 0.3 PJ/annum going forward.

10.2.5 *Peak Day Forecasts*

VENCorp provided a forecast of the 1:2 winter peak day for the general market in the 2006 APR. This forecast excludes exports, refill and gas-fired power generation.

For the export markets, GasNet is assuming 1 TJ/day at VicHub (based on an 80% load factor), and a peak day of 17 TJ/day at Culcairn, which is the current capacity constraint.

Storages are not expected to be filled on the peak day.

With respect to gas-fired power generation, there is wide variation in the observed peak day, particularly given that the relevant peak day volume is coincident with the total system peak day. Forecasting is complicated by the fact that gas-fired power generation is a controllable load driven by prices in the electricity market.

Based on historical analysis and previous statements from VENCorp, GasNet is projecting a peak day contribution of 50 TJ/day from gas-fired power generation.

10.2.6 *Supply Volume Forecasts*

GasNet also requires a forecast of injection volumes at each of the five gas injection points on the PTS.

Forecasts of the annual and peak day injection volumes are required by the Tariff Model in order to determine flow paths and to allocate costs to the tariff withdrawal zones.

A forecast of the winter injection volumes is also required in order to calculate the injection tariffs.

There is no independent source of information that provides injection volume forecasts. Gas supply is a competitive process whereby retailers and gas producers compete with each other to supply the demand for gas.

The forecast annual and peak injection volumes for the Third Access Arrangement Period are set out in Table 10.4 below.

The forecast winter injection volumes, required to calculate the injection tariffs, are shown in Table 10.5.

Table 10.4 - Forecast Annual and Peak Injection Volumes (Annual (PJ))

Injection Point	**2008**	**2009**	**2010**	**2011**	**2012**
Annual					
Longford	150.0	150.0	150.0	150.0	150.0
Port Campbell	49.2	51.8	55.2	56.7	59.0
Culcairn	3.0	2.0	1.0	0.5	0.5
Pakenham	20.0	20.0	20.0	20.0	20.0
Dandenong	0.3	0.3	0.3	0.3	0.3

Total	**222.5**	**224.1**	**226.5**	**227.6**	**229.9**
Peak	**2008**	**2009**	**2010**	**2011**	**2012**
Longford	830	830	830	830	830
Port Campbell	272	289	303	315	328
Culcairn	34	23	18	15	15
Pakenham	67	67	67	67	67
Dandenong	30	30	30	30	30
Total	**1,223**	**1,239**	**1,248**	**1,256**	**1,270**

Table 10.5 - Winter Volumes Injection Forecast (PJ)

Injection Point	**2008**	**2009**	**2010**	**2011**	**2012**
Longford	66.0	66.0	66.0	66.0	66.0
Port Campbell	25.7	27.1	28.9	29.7	30.9
Culcairn	2.4	1.6	0.8	0.4	0.4
Pakenham	7.0	7.0	7.0	7.0	7.0
Total	**101.1**	**101.7**	**102.7**	**103.1**	**104.3**

The gas injection forecasts have been derived from a combination of historical data, known developments in the producing fields, and from the necessity to balance supply and demand each year.

Known Developments

The Yolla gas field has been commissioned and is now producing at close to its planned capacity of 67 TJ/day. It is anticipated that Injections will be 20 PJ/annum over the forecast period.

In the Otway Basin, the Minerva and Casino fields are currently in production, and will be supplemented by the Thylacine/Geographe fields during 2007. Total annual production is likely to exceed 120 PJ/annum. It is anticipated that production will be split between Victoria and South Australia, and that volumes of between 50 to 60 PJ/year will be injected into Victoria. However the actual volumes injected into Victoria can only be conjectured.

The underground storage and the LNG facility will continue to be available to balance demand on the winter peaks.

The Longford/VicHub Injection point is and will remain the largest supplier into Victoria. However volumes are expected to fall as competition intensifies from Yolla and the Otways.

Pakenham Injection Point

The Yolla gas field in Bass Strait is projected to supply base load gas volumes of 20 PJ/annum and a peak of 67 TJ/day (82% load factor).

The profile should be reasonably flat across each year of the Third Access Arrangement Period, giving a winter volume of 7.0 PJ.

<u>Longford/VicHub Injection Point</u>

Longford has supplied in the order of 200 PJ/annum over the last 5 years, and a peak injection averaging approximately 880 TJ/day.

Whilst there is ample spare capacity at Longford, it is anticipated that both peak and annual volumes will fall in competition with Yolla and the Otways.

Assuming that Yolla and the Otways supply 70 PJ/annum by 2008, GasNet forecasts a Longford injection volume of 150 PJ/annum. It is assumed that further growth in gas demand will be met from the Otways and underground storage.

GasNet forecasts the peak Injection volume will fall to 830 TJ/day.

Based on the historical injection profile, the winter volume is forecast to be 44% of annual volumes, or 66.0 PJ/annum.

<u>Port Campbell (Otways gas and Underground storage)</u>

Port Campbell has traditionally supplied up to 10 PJ/annum from the underground storage during the winter months, but in 2006 this was supplemented by base load injections of Otways gas to give a total of 22 PJ/annum.

GasNet expects base load injections to increase as the Thylacine/Geographe fields are brought into production in 2007. GasNet projects a fixed 45 PJ/annum of base load injections from 2008. The balancing injections, starting at 4.2 PJ in 2008 (which will principally come from underground storage) are forecast to grow as the underlying gas demand grows.

On the peak day, the injection volume from Port Campbell is calculated as the balancing item after deducting the forecast peak day volumes from all other injection sources. This value is tested against the notified production capacity (VENCorp APR 2006) and the known capacity of the South West Pipeline to ensure that the volumes can be carried.

The winter volumes are calculated as the balancing item between total system winter volumes and winter volume injections from all other sources. The total winter volume is derived using the published monthly profile from the VENCorp APR, plus estimates for gas-fired power generators and exports. This analysis indicates that winter volumes will be 53.2% of annual injections at Port Campbell.

<u>Culcairn</u>

Over the last 5 years Culcairn injections has varied from a low of 0.8 PJ/annum in 2004 to a high of 4.0 PJ/annum in 2006.

These injections are concentrated in the winter months when Victorian prices are highest.

GasNet projects annual injections of 3.0 PJ in 2008. However, as export volumes increase, and as gas trading activity is likely to increase at the Culcairn hub, GasNet projects the injection volumes to fall to 0.5 PJ/annum by 2012.

Based on historical analysis, GasNet forecasts a peak day injection load factor initially of 24%[45], and winter volumes of 80% of the annual volumes.

<u>Dandenong</u>

The LNG facility at Dandenong is used principally for peak shaving.

Over the last 5 years, injections have varied from a low of 88 TJ/annum in 2005 to a high of 320 TJ/annum in 2004. GasNet projects an annual volume of 300 TJ/annum going forward, which is marginally higher than historical averages. This is consistent with the view that LNG will be utilised to a greater extent in the new VENCorp gas market.

Peak injections are assumed to be 30 TJ/day.

A winter volume forecast is not required because there is no injection tariff at Dandenong.

[45] Load factor is defined as Annual Volume/365/Peak day Volume

11 Determination of Reference tariffs

11.1 Background to tariff methodology

GasNet, as owner and maintainer of the PTS, is responsible for determining the Reference Tariffs to apply on the PTS over each Access Arrangement Period, and also for the billing and collection of the Reference Tariffs. GasNet has set and administered the Reference Tariffs for the last nine years, covering two Access Arrangement Periods. The current reset will establish Reference Tariffs to apply for the Third Access Arrangement Period.

GasNet's Current Tariff Model is complex both in its derivation and in its application. A detailed description of the design and derivation of the Current Tariff Model can be found in GasNet's submissions on the Second Access Arrangement or in the Second Access Arrangement itself, and will not be repeated here.

In the First Access Arrangement Period (i.e. 1999-2002), the Tariff Model included three Injection Pipelines and 12 Withdrawal Zones. Injections were charged on the five peak Injection days, and Withdrawals were charged on the five peak Withdrawal days for Tariff-D customers, and on the winter volume Withdrawals for Tariff-V customers. There was also an annual withdrawal charge for both Tariff-V and Tariff-D customers.

In the Second Access Arrangement Period, a number of modifications were made in light of experience, and due to changed circumstances. In particular:

(a) an Injection Point was added at Pakenham to supply Yolla gas into Melbourne, and Injection Tariffs were levied on the 10 peak Injection days;

(b) the Withdrawal Tariffs were simplified and applied only on a per GJ basis;

(c) a number of prudent discounts were offered to deal with potential bypass threats (generally for Withdrawals near to existing Injection Points); and

(d) for the same reason, the number of Withdrawal Zones was increased to 15.

GasNet is proposing significant revisions to the Tariff Model for the Third Access Arrangement Period.

The most significant issue going forward is the proposal for significant augmentation and refurbishment of the PTS over the Third Access Arrangement Period (see section 7 of this Submission). The proposed capital expenditure will lead to a further increase in tariffs, and will change the tariff relativities between Users.

In comparing 2007 Reference Tariffs with the tariffs proposed for the Third Access Arrangement, it is important to note that the current Reference Tariffs are approximately 15.5% below the level that would have applied had the forecast tariff path under the approved CPI-X tariff formula had been followed. The tariffs fell primarily because significant rebates matched to Yolla Injections were not paid in 2004 and part of 2005, due to the delay in Yolla coming onstream. The subsequent over-recoveries against the annual target revenue in those years were rebated to Users as lower Reference Tariffs in 2006 and 2007.

This fall in Reference Tariffs is an anomalous result. In considering the extent to which tariffs are higher in the Third Access Arrangement Period, it is appropriate to consider the original forecast tariffs as the base for the calculation of changes.

11.2 Tariff revisions 2008-2012

GasNet has reviewed the operation and effectiveness of the Current Tariff Model, in light of the substantial movement in GasNet's capital expenditure that is expected in the Third Access Arrangement Period.

The Current Tariff Model is extremely sensitive to changes in volumes, particularly on the country laterals and on Injection Pipelines, and to the timing and location of capital expenditure.

GasNet believes it is now opportune to make a significant revision to the Current Tariff Model. In particular, the revised cost allocation and tariff methodology (i.e. the New Tariff Model) proposed by GasNet will promote greater stability, transparency and simplicity in Reference Tariffs going forward, while maintaining significant cost reflectivity.

The main areas of proposed revision relate to:

(a) the method for allocating costs to the forecast gas flows;

(b) the Tariff-V tariff structure; and

(c) the Injection Point tariff structure.

A number of other minor changes are also proposed, as discussed below.

GasNet proposes to retain the current separation between Injection and Withdrawal Tariffs, the current separation of Withdrawal Tariffs for 'V' and 'D' customers, and the current zonal boundaries (with the exception of an additional zone at Geelong). Most other elements, including the flat "anytime" rate for all withdrawals, of the Current Tariff Model will be carried over and are as described in GasNet's submission on the Second Access Arrangement.

11.3 Proposed cost allocation and tariff setting

11.3.1 Cost allocation

The Current Tariff Model allocates indirect costs[46] on a postage stamp basis, and direct costs on a "zone gate" approach. Under the "zone gate" approach, gas flows are allocated a share of the asset costs (capital and direct operating costs) of each asset segment on the forecast flow paths taken by the gas through the PTS. In effect, each pipeline segment is assigned a separate unit cost rate ($/km/GJ) depending on the costs associated with that segment, and the volume utilisation of that segment.

The unit cost rates on each segment can shift up or down significantly from year to year, depending on changes in forecast volumes, and whether capital expenditure is incurred on that segment.

GasNet proposes to retain the current allocation of indirect costs on a postage stamp basis, but to replace the allocation of direct costs with a simpler distance based unit cost rate across the PTS. That is, the same unit rate ($/km/GJ) will be applied to each asset zone, irrespective of the costs of the pipeline segment, the volume carried by the segment or the capital expenditures allocated to that segment. There will be one rate for peak flows, and another for annual flows.

However, to retain a reasonable level of cost reflectivity, a separate distance-based rate (annual and peak) will be calculated for the Injection Pipelines as a whole and for the Withdrawal Pipelines as a whole.

A consequence of this change will be that both the tariffs and the relativities between tariffs will be more stable over time, and will be far less sensitive to changes in volumes and the value and location of capital expenditure on the system.

For example, the relativity between the Longford, Port Campbell and Culcairn Injection tariffs will be more stable over time, and will be less dependent of the level of flows or capital expenditure on the separate pipelines.

Within the Withdrawal Zones, the relevant direct costs are allocated to annual and peak flows in the ratio 65:35. The corresponding distance-based annual and peak rates are then derived for the whole Withdrawal system. These rates are then used to allocate the direct costs to each off-take according to the distance to the off-take from the relevant injection point, and the annual and peak flow through that off-take. Costs are then allocated to the Tariff-D and Tariff-V users according to the forecast of annual and peak flows for Tariff-D and Tariff-V at that off-take. The off-takes within a Withdrawal Zone are grouped to derive the total direct costs to be allocated to Tariff-D and Tariff-V for that Zone.

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[46] Indirect costs includes corporate overheads and other indirect operating costs, the return on and of general business assets, and assets rolled-in to the Capital Base under the system-wide benefits test.

As in the current 'zone-gate' model, Tariff-D is charged a simple annual rate, derived by dividing the allocated direct costs plus postage stamp indirect costs by the forecast annual Tariff-D volume in each Zone.

However, as discussed in the next section, the Tariff-V users are charged a global postage stamp rate, derived by dividing the sum of the direct and indirect costs allocated to Tariff-V in each Withdrawal Zone by the total system Tariff-V annual volume.

Within the Injection Zones, the related direct costs are similarly allocated to annual and peak flows in the ratio 65:35, and distance-based annual and peak rates are derived for the Injection Pipelines (this differs from the current model where all costs are allocated on peak flows alone). As in the current 'zone gate' model, no indirect costs are allocated to the Injection Pipelines. A total cost is then allocated to each Injection Pipeline according to the distance of each Pipeline, and the forecast annual and peak injections into that Pipeline. As described below, the injection charge is levied on the injections over the Peak Period, and is derived by dividing the allocated cost by the forecast Peak Period injections for that Injection Pipeline.

11.3.2 Tariff-V Tariff Structure

GasNet proposes to simplify the charging of Tariff-V customers by employing a single rate across the PTS. That is, all gas Withdrawals from the PTS which are allocated to Tariff-V will pay the same tariff rate.

It is anticipated that this revision will significantly simplify the administration of customer accounts by retailers, and will promote retail gas competition.

11.3.3 Injection Charges

It is proposed to charge the Injection tariff as a single flat rate over the Peak Period (being the winter months of June to September).

This will improve predictability and transparency, since the Injection Tariff will be known in advance.

Under the Current Tariff Model, it is impossible to know what the Injection Tariff will be from one day to the next. Moreover, the very high level of the current Injection Tariffs falls disproportionately on those injectors who provide the Injections required to balance the PTS during the current ten day period.

11.3.4 Other Changes

The changes GasNet proposes are:

(a) to separate Geelong from the Metro zone. With the increased gas volumes flowing on the SWP, Geelong will have a bypass opportunity to obtain supply direct from the SWP, thereby avoiding the Metro zone tariff;

(b) to amend the cost allocation between peak and annual flows in the New Tariff Model from the current 60:40 ratio to 65:35, to reflect the fact that the PTS is now more constrained than over the last five years; and

(c) to revert to the standard real straight line depreciation profile for the SWP (rather than partially deferred depreciation as in the Second Access Arrangement Period) now that it is anticipated that significant volumes will flow on the SWP.

11.4 Rationale behind proposed changes

In Schedule 5 of GasNet's submissions on the Second Access Arrangement, GasNet outlined a range of tariff design objectives which it believes are appropriate to the PTS.

These are:

(a) efficiency, in terms of the promotion of efficiency in:

  (i) customers' usage of Pipeline system;

  (ii) the operation and maintenance of Pipeline system; and

  (iii) investment in system;

(b) simplicity and predictability – enabling Users to identify the cost impact of their usage decisions, and ensuring administration costs are not excessive and barriers to entry are minimised;

(c) robustness, in light of possible changes to the future development of the Pipeline system, and changes in demand and supply patterns;

(d) price stability - avoiding unnecessarily large price shocks at subsequent reviews; and

(e) consistency with full retail competition - ensuring that transmission tariffs do not artificially impede customer churn.

There is a tension between these principles which must be resolved according to the unique circumstances of each Pipeline.

11.4.1 Cost Allocation

The cost allocation procedure in the Current Tariff Model suffers from a lack of robustness and stability over time. The tariffs are very sensitive to the level of utilisation of each pipeline segment, and the level and location of capital expenditure.

The volume-distance approach proposed for the New Tariff Model will provide stability over time, which will create greater confidence and certainty for both gas Users and producers.

The Current Tariff Model appears at first sight to be highly cost reflective. However, the Current Tariff Model is very sensitive to short term trends in volume levels in each Pipeline segment and to the short term timing of capital expenditure. Therefore, the Current Tariff Model sends an erratic and short term indication of true costs of a Pipeline segment and the tariffs resulting from this cost allocation are not necessarily reflective of long-run costs over the life of an asset.

GasNet submits that the aim of the Tariff Model should be to create tariffs which are a reasonable reflection of long-run costs, subject to the other objectives listed above. This is consistent with the Code and with the approach the Commission has adopted in assessing whether a proposed tariff structure for a particular Pipeline is appropriate, which is to balance the efficiency gains against the administrative simplicity of the various tariff structures.[47]

The proposed volume-distance methodology retains the main driver of costs, which is distance. Again, this is consistent with the Commission's view that distance based tariffs are the most efficient means of charging for gas transportation.[48]

It is well established that gas Transmission Pipelines exhibit economies of scale, which means that a larger diameter Pipeline has a lower unit rate per km than a smaller diameter Pipeline (assuming the same utilisation). This will be partially managed in the New Tariff Model by separating the PTS into the larger Injection Pipelines, and the smaller Withdrawal Pipelines, and using separate distance-based rates for each.

However, the New Tariff Model abstracts from the age and condition of individual assets, and the current level of utilisation of those assets, in the short term. It does not reflect the current levels of capital expenditure on specific Pipeline segments, but GasNet submits that over the life of the assets, all segments will require augmentation and upgrade at some point in time. Accordingly, the New Tariff Model is reflective of the costs of individual segments of the PTS over the long term and sends appropriate price signals to end users.[49]

In the short term, the New Tariff Model is likely to lead to lower tariffs than under the Current Tariff Model for some Users and higher tariffs for others. Over the longer term, GasNet expects this to even out for the reasons given in the preceding paragraph. Further, any short term adverse consequences will be outweighed by the other benefits - namely increased simplicity, predictability, robustness and price stability, and the positive impact on retail competition.

11.4.2 Tariff-V Tariff Structure

The Tariff-V customers are the residential and small industrial/commercial customers. There are approximately 1.4 million Tariff-V customers supplied by the PTS. In contrast, there are approximately 450 Tariff-D customers.

The Tariff-V customer pays a significantly higher price for delivered gas (~$9/GJ) compared to Tariff-D customers (~$4/GJ), largely because the Tariff-V customer pays a higher distribution charge. Consequently,

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[47] For example, see ACCC, *Amadeus Basin - Darwin Pipeline Final Decision*, 4 December 2002, at p110.

[48] ACCC, *Amadeus Basin - Darwin Pipeline Final Decision*, 4 December 2002, see p110.

[49] In the *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, the ACCC stated that the chosen tariff structure should send the appropriate pricing signals to end users (p154).

the GasNet transmission charge for Tariff-V customers is on average only 4-5% of the delivered price, whereas for Tariff-D customers it is approximately 8-10%.

In addition, the annual cost of gas is a relatively small proportion of the total household budget. Consequently, the GasNet transmission tariff is unlikely to have any bearing on the consumption patterns of Tariff-V customers, or at most a very minor effect. Therefore the economic efficiency benefit of a fully cost reflective tariff structure for Tariff-V customers is likely to be small.

In contrast, the Tariff-V tariff structure can have a significant impact on competition in the gas retail market. GasNet understands that most retailers amalgamate the PTS transmission tariff zones for the purpose of marketing gas, in order to save administrative costs. A simple, predictable and stable across-the-board flat rate tariff for Tariff-V customers will reduce administrative costs and encourage new entrants and smaller retailers to enter the market, which will promote customer churn and therefore gas retail competition.

GasNet submits that the benefits of a simple tariff structure to retail competition (and the resulting efficiency gains) outweigh the relatively small economic efficiency benefits of a complex zonal tariff structure for Tariff-V customers.

11.4.3 Injection Tariffs

A major problem with calculating Injection Tariffs on ten peak days as in the Current Tariff Model is that gas suppliers cannot know the gas Injection Tariff in advance. This is particularly problematic for suppliers who inject specifically to meet those peaks on the days of the year when the PTS requires peak balancing. GasNet understands that the Market does not price the peak Injection Tariffs into the gas bids, which must distort wholesale Market outcomes. For example, traders who only buy but do not sell into the Market will obtain gas without paying the associated Injection costs.

The objective of the Tariff Model is to promote economic efficiency. Economic theory suggests that the optimal outcome is achieved if a price is set at marginal cost. In the case where there is a significant difference between peak demand and off-peak demand, the theory of peak load pricing also suggests that the off-peak demand should be charged the short run marginal cost, whilst the peak demand should be charged the sum of the short run marginal cost and the capacity related capital costs.

This is generally interpreted to mean that the capacity related capital costs should be charged to the peak demand, loosely speaking because this demand ‘causes’ the Pipeline to be expanded.

This principle is commonly applied to contract carriage Pipelines where a large proportion of the costs are charged as a peak reservation tariff (provided the utilisation of the Pipeline is high). However, it is not necessarily the case that this principle applies to a Market Carriage Pipeline.

The theory assumes that the peak and off-peak periods are quite distinct and there are no cross-price effects. However, the relationship between Pipeline capacity expansion and the peak demand is not simple. In reality, a Pipeline expansion would consider the growth of demand over time, and would put an appropriate discounted value on the benefits of supplying the growth in off-peak demand in the future. The optimal design is likely to be a function of the shape of the load duration curve, the growth rate and the discount rate.

GasNet submits that a flat tariff over the winter Peak Period represents a reasonable balance between economic efficiency, tariff certainty and the benefits to the gas market as a whole.

11.5 Peak pricing

As noted above, one of the elements from the Current Tariff Model which GasNet is proposing to retain is the flat "anytime" tariff for all withdrawals. This tariff is levied monthly on actual flows and includes specific rates for Tariff-D and Tariff-V customers.[50]

GasNet's submissions in relation to the Second Access Arrangement provided justification for this "anytime" tariff (see section 9.4 and Schedule 5) and the Regulator approved this amendment for the Second Access Arrangement Period. Nevertheless, GasNet has reiterated some of the key arguments below because the Regulator has raised this issue with GasNet in recent discussions.

Cost and complexity

Peak charges are costly for GasNet and retailers to administer, and the administration cost is disproportionate considering that the transmission tariff is only 5-10% of the end-use charge for most users.

Peak charges also increase the complexity of customer churn, which may impede competition in the retail gas market.

Effectiveness

GasNet believes that the majority of users do not respond to peak pricing signals. The Commission also took this view in the 2002 Final Decision, in which it stated:[51]

> "*Furthermore, as noted in the Draft Decision, there is little evidence that end users of the PTS respond to pricing signals. The Commission consider that, on balance, it is quite unlikely that peak withdrawal tariffs have much effect on overall demand*."

[50] Prior to the Second Access Arrangement Period, the withdrawal tariffs on the GNS were structured as a combination of an "anytime" rate (a fixed $/GJ over the whole year), and a peak charge, with approximately two thirds of revenue recovered from the peak charge.

[51] 2002 Final Decision, p 228.

For Tariff-V customers, GasNet believes that peak pricing signals are unlikely to have significant effect on consumption decisions because:

(a) the GasNet transmission tariff is unlikely to have any bearing on the consumption patterns of Tariff-V customers, or at most a very minor effect (see section 11.4.2); and

(b) those customers have a limited ability to respond to day-to-day pricing signals because retail charges are levied on a bi-monthly basis. At best the only realistic response to peak or winter pricing would be for residential customers to reduce heating load by changing behaviour or by installing efficient appliances or insulation.

However, given the heating load is the dominant component of the annual domestic consumption, and that there is still 27% of heating outside the winter (June-September), a simple annual charge sends a viable signal to achieve the same end.

With respect to Tariff-D customers, it is unlikely that a peak charge would be effective in eliciting a customer response since the load factor of this segment of the market is already very high at approximately 80%. Further, in relation to the 5-day pricing signal used in the First Access Arrangement Period for Tariff-D customers, GasNet submits that it:

(a) was ineffective as a price signal because the 5 chargeable days were only known in hindsight, making it difficult for users to respond to the peak signal and plan their production around these peaks. This is particularly relevant to gas-fired power generators who must choose to generate or not on a day-to-day basis; and

(b) leads to unpredictability of liabilities. Neither the retailer nor its customers can budget accurately for transmission charges when they are not known until well after the event.

A key issue for the effectiveness of peak pricing signals is how transmission tariffs are handled by retailers. Price signals are only useful to the extent that retailers pass the signals through to end users. In this context the relevant issue is how retailers package the suite of price signals from the wholesale market, the transmission system and the distribution system. However, this issue is outside the scope of this Submission.

Efficiency

As stated by the Commission, where a pipeline is not congested, the price signals provided by peak charges are inefficient because they lead to under-utilisation of the pipeline.[52]

This problem can be avoided on a contract carriage pipeline, since spare capacity can be utilised at an interruptible tariff, which has no peak charging component, and therefore there is no disincentive to utilise the spare capacity. On the other hand, capacity which is required on a firm basis is charged at a take-or-pay rate based on the peak usage, which

[52] 2002 Final Decision, p 228.

therefore sends the appropriate price signal for the value of capacity. However, the Victorian market carriage system does not include a mechanism to deal with this issue.

Overall, GasNet believes that the benefits of simplicity, tariff certainty and compatibility with full retail contestability continue to outweigh the benefits of peak pricing signals on withdrawal tariffs.

GasNet also submits that an amendment to the MSO Rules would be required to implement pricing signals which encourage Users to use the pipeline efficiently, without applying a peak price which would inhibit use of spare capacity when it is available. For example, GasNet has explored the concept of “MDQ capacity contracts” in a joint project with VENCorp. The proposal involved Users being offered capacity rights which would be charged on a take or pay basis, and demand above the capacity rights being priced like an interruptible tariff. This project is currently in abeyance, but GasNet would support further development of similar concepts.

11.6 Other Tariff Elements

11.6.1 Storage refill tariffs

GasNet intends to continue with a special tariff class for storage refill, based on the marginal cost of transporting the gas into a Storage Facility.

This is because storage is an interim holding point for gas, rather than a Withdrawal point in its own right.

The refill of the underground storage at Port Campbell requires the running of one or two Centaur compressors at Brooklyn. The cost of transporting gas into storage depends strongly on the daily refill rate. GasNet has assumed a moderate level of daily refill, and has determined a marginal cost of $0.20/GJ.

For refill of the LNG Storage Facility, the marginal cost is related to the operating costs of the Gooding compressor (since refill of the LNG Storage Facility is expected to occur principally in the winter). The marginal cost is determined to be $0.15/GJ.

11.6.2 Culcairn export tariff

Over the last five years, exports through Culcairn have been largely opportunistic in nature, usually in the off-winter months when gas prices in Victoria are low.

For the Third Access Arrangement Period, GasNet is forecasting exports of 5 PJ/year. This volume utilises the available AMDQ capacity of 17 TJ/day through the Interconnect Pipeline. An expansion of firm winter capacity would require significant additional capital expenditure.

The most likely customers for the export volumes are the proposed Uranquinty power station, near Wagga Wagga, and other end users in country NSW.

However, there is no assurance that these volumes will continue to flow, as the customers have the option of gas supply from Moomba via the MSP, or from Bass Strait via the EGP and gas swaps.

In light of the highly competitive nature of the market, GasNet is proposing that the Culcairn export tariff should be discounted to a level which still exceeds the incremental cost of supply. If the tariff exceeds the incremental cost of supply, then no User on the PTS can be worse off. As such, the proposed tariff is prudent.

To the extent that the tariff exceeds the incremental cost, the existing Victorian User can only be better off. However, if a higher tariff (based on the New Tariff Model) is applied to exports, there is a risk that the flows might not eventuate, which would therefore provide no immediate or future benefits to Victorian Users.

GasNet proposes an export tariff of $0.50/GJ, which exceeds the long-run incremental costs, and it is therefore a prudent discount.

11.7 Prudent Discounts

11.7.1 LaTrobe zone discount

In its submission on the Second Access Arrangement, GasNet proposed a prudent discount to apply to the LaTrobe zone tariffs. GasNet has re-evaluated these tariffs in the light of current volume forecasts and bypass pipeline costs.

The most significant change since 2002 has been the escalation in pipeline costs. Based on a conservative estimate of $55,000/inch/km for pipeline assets, GasNet believes that the bypass tariff will exceed the tariffs determined by the New Tariff Model.

Therefore, GasNet proposes not to apply a prudent discount to the LaTrobe zone. However, it should be noted that the bypass risk is strongly dependent on the demand in the LaTrobe zone. The LaTrobe Valley is the potential site for new gas-fired power station development, particularly if coal-fired plant is converted to base load gas supply (for example in response to greenhouse concerns). If this happens, or if demand increases significantly for any reason, bypass may be a risk and GasNet may need to submit revisions to the Third Access Arrangement during the regulatory period to address this risk.

11.7.2 Wodonga zone discount

For the same reasons discussed in section 11.7.1 in relation to the LaTrobe zone, GasNet has determined that a prudent discount is no longer required in the Wodonga zone.

11.7.3 Western zone discount

The bypass risk in the Western zone arises from the SEA Gas Pipeline which parallels the PTS between the towns of Warrnambool and Koroit. This is an existing pipeline, hence the bypass risk is not affected by the escalation in new pipeline costs.

Based on the latest volume forecasts and bypass costs, GasNet calculates the bypass tariffs to be:

Table 11.1: Bypass tariffs for Western zone ($2006)

	Tariff-D
Warrnambool	$0.078/GJ
Koroit	$0.162/GJ

11.7.4 Pakenham bypass tariff

In its submission for the Second Access Arrangement, GasNet argued that a bypass risk existed between the Dandenong offtake of the PTS and Pakenham, where gas is injected into the PTS from the Bass Gas production facility.

This facility is expected to inject approximately 20 PJ/annum at a high load factor. In the event that a bypass was constructed, this gas could be used to displace gas supply from Longford through the PTS.

It is not possible to say whether this gas would displace supply to Tariff-V or Tariff-D customers. GasNet proposes a prudent discount to Tariff-D customers. However, in order to maintain the simplicity and transparency of a postage stamp tariff for Tariff-V, GasNet does not propose a special discount offered for Tariff-V customers.

GasNet has re-estimated the cost of a bypass pipeline and associated regulators and heaters at Dandenong, and re-calculated the bypass tariff between Pakenham and Dandenong.

The proposed tariff is higher than the bypass tariff in the Second Access Arrangement, reflecting the increased cost of pipelines. It exceeds the direct costs determined on the PTS, and therefore is a prudent discount.

The bypass tariff is implemented as an Injection Tariff at Pakenham and a discounted Withdrawal Tariff in the Metro south east zone.

The Injection Tariff is determined as a proportion of the Longford Injection Tariff, pro-rated by distance from Pakenham to Dandenong. The discounted Metro South East zone Withdrawal Tariff is determined to be $0.142/GJ (in $2006) for Tariff-D.

11.8 Tariff path - revenue control

11.8.1 Previous revenue control method

GasNet has operated under an Average Revenue Yield control for each of the First Access Arrangement Period and the Second Access Arrangement Period.

Under an Average Revenue Yield control, GasNet forecasts an Average Transmission Tariff (ATT) for each year of the relevant Access Arrangement Period, and is permitted to earn the product of the ATT and the actual delivered gas volume in any given year. To the extent that actual revenues in any year differ from the permitted amount, a correction is made to subsequent tariffs to keep GasNet to the permitted amount, with appropriate adjustments for the time value of money (the K-Factor).

Therefore, GasNet will only earn the forecast building blocks revenue requirement if actual delivered volumes equate to the original forecast of delivered gas volumes. Any deviations between actual volumes and the original forecast volumes is a risk that is borne by GasNet.

11.8.2 *Historical experience*

Based on the actual volumes delivered over 2003 to 2006, and on the expected volumes for 2007, gas volumes are likely to fall below the original forecast volumes by on average 4.6% per annum. In particular, the actual volume in 2005 was 11.4% below the forecast, resulting in a proportionate decrease in permitted revenues.

The large fall in gas volumes in 2005 was due to a combination of lower economic growth, reductions due to accidents at two industrial customers, and significantly lower heating load in that year. The lower heating load arose from the fact that 2005 was the warmest winter on record in Victoria.

11.8.3 *Proposed revenue control - Third Access Arrangement Period*

GasNet is concerned that the current revenue control method exposes GasNet to potentially very large revenue shortfalls.

These shortfalls are only weakly related to associated cost reductions in that:

(a) the savings in fuel gas costs in low demand years are small compared to the revenue lost from lower gas volumes. Moreover, to the extent that weather influences gas demand, there is only a weak correlation between the weather over the winter (when compressors are required) and the annual weather outcome; and

(b) the relationship of overall demand (and hence revenue) to the asset augmentation program is weak, and hence reduced revenue is not significantly offset by delayed capital expenditure. This is related to the fact that most augmentation capital is driven by local constraints which are not necessarily linked to the behaviour of the whole system. In addition, given the two to three year construction timeframe, the capital expenditure program lags behind the most recent trends in volume growth.

As noted above, GasNet is in a unique position of operating under a Market Carriage model. The resulting constraints are also noted above in section 2.2.

GasNet has reviewed the possible revenue control models going forward. The models typically used in Australia are:

(a) revenue cap (used by electricity transmission businesses);

(b) tariff basket (used by distributors); and

(c) price cap (used on contract carriage Pipelines).

GasNet has considered the alternative approaches available, and has decided to retain in principle the average revenue yield control. However, GasNet proposes two modifications to the model:

(a) GasNet will not be exposed to weather risk; and

(b) GasNet will retain an exposure to economy risks on volumes, but the associated revenue risk will be bounded.

The mechanism by which annual tariffs will be rebalanced under the proposed revenue control is set out in Schedule 4 of the Access Arrangement.

11.8.4 Weather risk

GasNet proposes to adjust the actual delivered gas volumes to reflect the volumes that would be expected in a standard winter. The standard winter is defined by the number of effective degree days as published in the VENCorp APR, which is the basis for the volume forecast proposed by GasNet over the Third Access Arrangement Period.

The weather adjustment is effected by:

> Weather-Adjusted Actual Volume = Actual Volume + (Standard EDD – Actual EDD) * Temperature Sensitivity

(a) The Actual EDD for any given year is the value determined by VENCorp.

(b) The temperature sensitivity is forecast by VENCorp and is used to derive the GasNet volume forecast.

It should be noted that there is some residual correlation between cold winters and increased compressor fuel use, and vice versa. GasNet estimates that the weather adjustment factor should be reduced by about 15%, which will be effected by multiplying the weather adjustment determined by the above formula by 85%.

Therefore the revenue permitted to be recovered by GasNet in each forecast year becomes:

> Forecast Target Revenue / Forecast Volume * Weather-Adjusted Actual Volume

11.8.5 Bounds on risk

The Average Revenue Yield control exposes GasNet to the deviation between the weather-adjusted actual volume and the forecast of gas volumes made at the commencement of the Third Access Arrangement Period.

GasNet is prepared to accept the deviations arising from normal variations in economic, housing and energy efficiency activity. However, as GasNet is largely a fixed cost business, it is inappropriate to expose the business to the possibility of large fluctuations in revenues, and the consequent impact on dividend distributions.

GasNet proposes an upper and lower bound on volume risk of ±5.5% which represents the maximum deviations from the base forecast in the VENCorp APR. Deviations outside this range are indicative of abnormal events to which GasNet should not be exposed.

11.9 Incentive Mechanism

11.9.1 Code requirement

Section 8.44 of the Code provides that a Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism to enable a Service Provider to recover all or a share of any returns from the sale of a Reference Service that exceeds the level expected at the beginning of the Access Arrangement Period. The mechanism should be designed to encourage the service provider to:

(a) increase the volume of sales of all Services;

(b) minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(c) develop new services in response to the needs of the market for Services;

(d) undertake only prudent investment; and

(e) ensure that Users and Prospective Users gain from any increased efficiency, innovation and improved sales (but not necessarily in the Access Arrangement period during which such increased efficiency, innovation or volume of sales occur).

11.9.2 Aspects of efficiency carryover

There are two aspects of an efficiency carryover for GasNet.

(a) the treatment of the carryover of efficiency gains (losses) made in the Second Access Arrangement Period in the Third Access Arrangement Period; and

(b) the efficiency carryover mechanism to be applied in the long term (i.e. 2012 onwards).

The first of these is discussed in section 9.5 of this Submission. The second is discussed below.

11.9.3 Post - 2012 incentive mechanism

GasNet has included a Fixed Principle in the Access Arrangement relating to how efficiency gains achieved in the Third Access Arrangement Period are to be treated in the fourth Access Arrangement Period.

The Fixed Principle proposed by GasNet is the same as the existing Fixed Principle incentive mechanism under the Second Access Arrangement with the following amendments:

(a) removal of fuel gas costs from benefit sharing allowance; and

(c) allowing for the regulator to exercise discretion in determining whether any efficiency loss should be carried over.

Removal of fuel gas costs

GasNet has removed fuel gas costs from the incentive mechanism on the basis they are beyond GasNet's control. As VENCorp operates the PTS, it effectively controls the fuel gas costs by, for example, determining when and how compressors will be operated. For these reasons, GasNet submits that it is not appropriate - nor is it within the spirit of the Code in terms of the incentive mechanism - for GasNet's incentive mechanism to be impacted by costs that are outside of its control.

Negative carry over going forward

In approving the Second Access Arrangement, the Commission took the view that efficiency gains and losses should be treated symmetrically in the incentive mechanism. That is, both a gain and a loss could be carried forward into the next Access Arrangement Period. The reason was to prevent GasNet from gaming the Regulator through expenditure adjustments (e.g. claiming a gain in one year and shifting expenses to the following year to claim a loss). The Commission also noted that GasNet was only subject to 30 percent of any losses incurred through the course of an Access Arrangement Period.

This notwithstanding, GasNet submits that net aggregate efficiency losses should not be carried forward in the manner required by the Second Access Arrangement in the future. This is because:

(a) the concern that outcomes can be gamed by cost shifting overstates the ability of companies to significantly defer or bring forward operating costs in practice;

(b) if, despite being a prudent and efficient operator, GasNet nevertheless incurs higher costs, the symmetric form of the benefit sharing allowance will penalise GasNet by reducing the approved costs in the next Access Arrangement Period below the efficient level. This would be both unreasonable, and inconsistent with section 8.1(a) of the Code, which requires that GasNet should be provided with the opportunity to recover the efficient costs of delivering the Reference Service; and

(c) other regulators, including the AER and ESC, have acknowledged that there may be circumstances where it is not appropriate to carry forward efficiency losses, such as where it could affect the regulated entity's ability to provide efficient services in subsequent Access Arrangement Periods.

Although GasNet believes that a symmetric benefit sharing allowance is not required and is not the appropriate method to address gaming issues, GasNet proposes that the Regulator should have the discretion to determine how any accrued negative carryover amount at the end of an Access Arrangement Period should be treated. This discretion should be exercised in accordance with the relevant principles of the Code. This approach is consistent with the approach taken by the ESC and the Essential Services Commission of South Australia.[53]

11.10 Pass through events

As with the Second Access Arrangement Period, GasNet proposes to include in the draft Access Arrangement a set of pass through rules which would permit GasNet to apply to the Regulator to pass through certain within-period cost changes.

GasNet's proposal does not differ significantly from the Second Access Arrangement that was approved by the Commission, except that GasNet:

(a) no longer proposes to include as a pass through event where there has been a change in one or more costs in the insurance comprising GasNet's minimum insurance level; and

(b) proposes to include asbestos risk as a pass through event.

Each of the proposed pass through events are beyond GasNet's control and any pass through is subject to approval by the Regulator.

In relation to asbestos risk, GasNet notes that the SAHA International report supports the inclusion of this risk be included as a pass through event. In particular, SAHA states:[54]

> "*From our experience, asbestos is a significant legitimate business risk faced by Gas Transmission companies around the world, and GasNet is no exception. Any estimate of the expected cost of asbestos related risk is necessarily subjective and a wide range of possible values is feasible, therefore, we recommend that GasNet seeks a specific cost pass through provision related to asbestos related risk.*"

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53 See for example: ESCOSA, *Proposed revisions to the Access Arrangement for the South Australian Gas Distribution System Final Decision*, June 2006; and ESC, *Review of Gas Access Arrangements Final Decision*, October 2002.

54 See Attachment E: SAHA International, Self Insurance Risk Assessment, 26 April 2007, page 18.

PART C - NON-TARIFF ISSUES

12 Non-tariff elements

12.1 Allocation of responsibilities

Consistent with section 10.2 of the Code, there has been an allocation of responsibilities between GasNet and VENCorp relating to the different elements of an Access Arrangement.

The current allocation of responsibility reflects the Second Access Arrangement. Each of GasNet and VENCorp is responsible for the description of the Services Policy and Reference Tariffs. However, VENCorp is responsible for describing the terms and condition of access, the Capacity Management Policy, the Trading Policy and the Queuing Policy. GasNet is responsible for the Extensions/Expansions Policy.

GasNet does not propose to deviate from this allocation of responsibility for the Third Access Arrangement Period. GasNet notes, however, its comments in section 2.2.2 about the anticipated changes to the Victorian legislative arrangements.

12.2 Services Policy

GasNet does not propose to deviate from the Services Policy contained in the existing Access Arrangement.

The arrangements under the existing Services Policy are as follows:

(a) As the PTS is a Market Carriage transmission system, Users and Prospective Users of the PTS are offered one Reference Service (or bundle of Reference Services), being the transportation of gas in accordance with the MSO Rules.

(b) VENCorp, as operator of the PTS under the MSO Rules is responsible for the provision of the Reference Service.

(c) Although it is a Service Provider under the Code, GasNet does not, under the MSO Rules, provide gas transmission Services directly to Users.

(d) For the purposes of Reference Tariff calculation, the Reference Service comprises two components:

   (i) the VENCorp Services, which VENCorp provides itself (these are dealt with in the VENCorp Access Arrangement); and

(ii) the Tariffed Transmission Service, being the benefit of the availability of the PTS (which is dealt with in GasNet Access Arrangement).

Again, however, GasNet notes its comments in section 2.2.2 about the anticipated changes to the Victorian Market Carriage regime.

12.3 Terms and conditions of service

The terms and conditions on which Users obtain access to the Reference Service are set out in the MSO Rules. Consistent with section 10.2 of the Code and the Second Access Arrangement, responsibility for complying with the obligation to include terms and condition of supply in an Access Arrangement have been allocated to VENCorp.

12.4 Capacity management policy

The PTS will remain a Market Carriage Pipeline.

12.5 Trading policy

Under section 3.9 of the Code an Access Arrangement for a Covered Pipeline which is described in an Access Arrangement as a Contract Carriage Pipeline must include a Trading Policy. However, as the PTS will continue to be a Market Carriage Pipeline, section 3.9 of the Code does not apply.

12.6 Queuing policy

Consistent with section 10.2 of the Code and the Second Access Arrangement, responsibility for the requirement to include a Queuing Policy in an Access Arrangement has been allocated to VENCorp.

12.7 Extensions and expansions policy

Section 3.16 of the Code provides that an Access Arrangement must include a policy which:

(a) sets out the method to be applied to determine whether any Extension or Expansion to the Pipeline should be treated as part of the Covered Pipeline; and

(b) specifies how an Extension or Expansion which is to be treated as part of the Covered Pipeline will effect tariffs.

The first of these requirements is dealt with in clause 5.1 of the Access Arrangement. Consistent with the Second Access Arrangement, clause 5.1 provides that any Extension to the PTS will be covered by the Access Arrangement unless GasNet gives a notice to the Regulator stating that the Extension will not form part of the Access Arrangement.

Clause 5.1 provides that any Expansion of the PTS will be covered by the Access Arrangement, except where an Expansion is required to increase the capacity of withdrawals at Culcairn above the current capacity of 17 TJ/day, that Expansion will not be covered by the Access Arrangement unless GasNet gives a notice to the Regulator stating that the Expansion will not form part of the Access Arrangement. This is on the basis of the market influences and competitiveness between the Interconnect Pipeline and the EGP. Therefore, GasNet considers it not appropriate to regulate these tariffs.

In relation to the second requirement, clause 5.2 of the Access Arrangement deals with the effect of an Extension or Expansion on Reference Tariffs. Clause 5.2 provides that all revisions to the Access Arrangement to increase the Capital Base to recognise the costs incurred in constructing an Extension or Expansion will be considered under the relevant provisions of the Code (including sections 8.15 to 8.19).

12.8 Capital Redundancy

GasNet proposes to adopt a capital redundancy policy which provides that the Capital Base may be adjusted to take account of wholly or partially redundant assets.

This is consistent with the policy approved by the Regulator as part of the Second Access Arrangement.

12.9 Review and expiry of Access Arrangements

The adoption of a five year Access Arrangement Period is consistent with general practice and with the First and Second Access Arrangement Periods.

In addition, the Revisions Commencement Date coincides with the expiration of the Service Envelope Agreement.

GasNet and VENCorp have agreed that the Revision Commencement Date will be 1 January 2012.

13 KPIs

13.1 Code requirements

Category 6 of Attachment A of the Code includes a requirement that KPIs be included in the access arrangement information. The Code cites two examples of these KPIs:

(a) industry KPIs used by the Service Provider to justify "reasonably incurred" costs; and

(b) the Service Provider's KPIs for each pricing zone, service or category of asset.

13.2 KPI concepts

GasNet has evaluated its forecast of operating costs against a range of other gas transmission companies across Australia. Comparative KPIs have been used to make a broad assessment of the efficiency and reasonableness of costs incurred by GasNet in providing its transmission services.

In its AA Information for the Second Access Arrangement Period, GasNet included a wide range of indicators as measures of its comparative performance. However, GasNet submits that many of the measures previously used utilise indicators which are not within the immediate control of management. For example, capacity utilisation is a valid measure of the overall economic efficiency of the pipeline, but it is not directly under the control of the management of the transmission pipeline company. GasNet believes that the requirement to justify that operating costs are reasonably incurred in the Code is intended to refer to those costs which are within management's control.

Therefore, indicators which utilise throughput and capacity as output measures are invalid because they are only weakly related to operating costs, and are not within the control of management.

For this reason it is now more common for pipeline companies to report operating costs as they relate to:

(a) the length of the pipeline; and

(b) the capital cost of the system (at the replacement cost).

The Commission has concurred with this approach in the Roma to Brisbane Pipeline Final Decision:[55]

> *"The ACCC noted that the varying degrees of available capacity, throughput and utilisation of Australian comparator pipelines tend to undermine the value of capacity or throughput based performance indicators in the absence of acceptable mechanisms of normalisation. Accordingly, the ACCC in its draft decision agreed that the benchmarks provided by APTPPL are appropriate performance indicators."*

[55] ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p 231.

GasNet has employed the comparative statistics used recently for the Roma to Brisbane Pipeline Access Arrangement. The comparator pipelines are:

(a) Moomba to Sydney Pipeline;

(b) Moomba Adelaide Pipeline;

(c) Goldfields Gas Pipeline;

(d) Dampier Bunbury Pipeline; and

(e) Roma to Brisbane Pipeline.

The statistics have been taken from data published in the Access Arrangements for the relevant pipelines for the years between 2004 to 2006. This difference in timing have been accepted by the Commission as not material.[56] Data from other pipelines is either not available, or is dated.

GasNet's operating costs exclude the cost of fuel for compressors and heaters. This is because:

(a) this cost is not within GasNet's control (compressor operations are controlled by VENCorp); and

(b) other pipeline companies have a range of inconsistent methods to fund the cost of compressor fuel (some companies require shippers to provide the fuel used in operations).

Further, GasNet's operating costs are not directly comparable to the other companies in the sample because the system control function is performed by VENCorp, whereas all other pipelines in the sample perform this function themselves. In the 2002 Final Decision the Commission accepted a cost of $0.62 million per annum for this function, as recommended by GasNet's consultant Cap Gemini. Accordingly, GasNet has updated this figure for inflation to $0.70 million and added this amount to the operating costs included in table 13.1.

13.3 KPIs

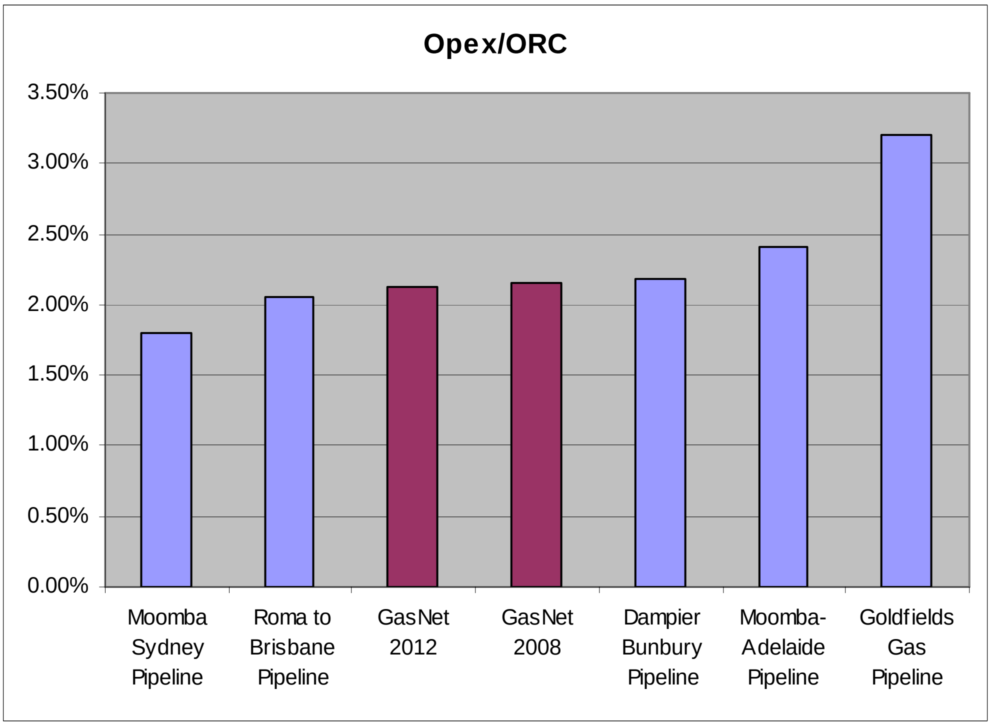
Table 13.1 shows the relevant KPIs for the sample of companies compared to the statistics for GasNet in 2008 and 2012, in $2006.

56 ACCC, *Roma to Brisbane Pipeline Final Decision*, 20 December 2006, p 232.

Table 13.1: Comparative KPIs

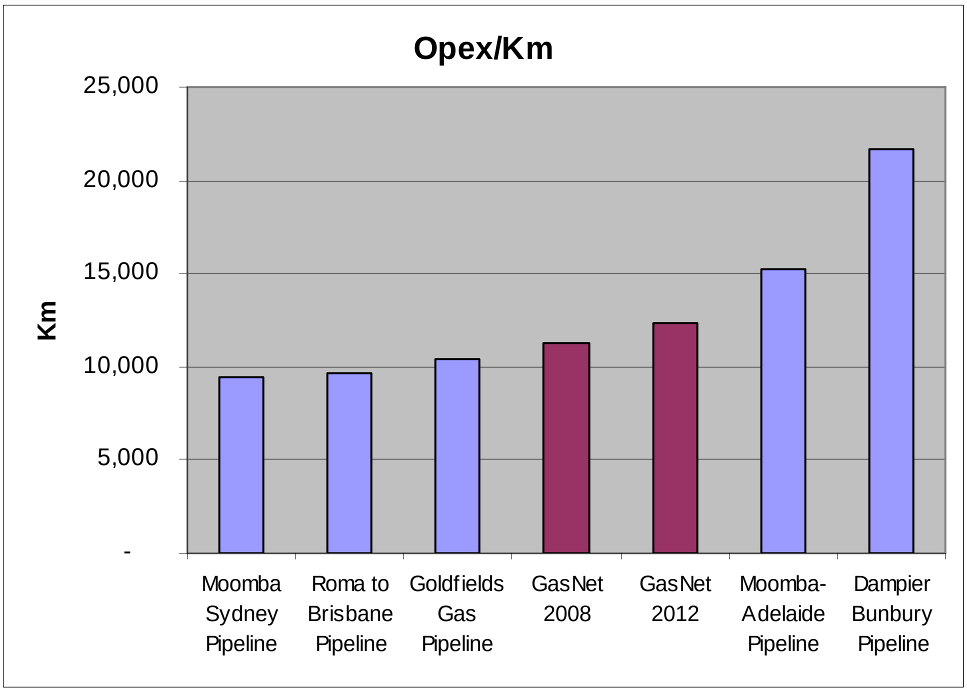
Pipeline	Opex/ORC	Opex/km
Moomba Sydney Pipeline	1.80%	$9,404
Roma to Brisbane Pipeline	2.05%	$9,691
Dampier Bunbury Pipeline	2.18%	$21,677
Moomba Adelaide Pipeline	2.41%	$15,262
Goldfields Gas Pipeline	3.20%	$10,450
GasNet 2008	2.15%	$11,281
GasNet 2012	2.13%	$12,327

Figure 13.1: Operating costs as a percentage of ORC



On this measure, GasNet falls approximately in the middle of the range, at just over 2%. By the end of the Third Access Arrangement Period, GasNet will have additional compressor stations in operation (see section 7). Although this will increase operating costs, GasNet's costs are still comparable to other gas transmission companies.

Figure 13.2: Operating costs per kilometre



In relation to operating costs per kilometre of pipeline, GasNet is once again in the middle of the range. However, a proportion of GasNet's pipelines are located within urban areas where operating costs are significantly higher. The comparator sample consists of long distance cross country pipelines for which operating costs would be expected to be lower. For this reason GasNet performs well on the measure.

In summary, these KPIs (which are the two most relevant) demonstrate that GasNet's proposed operating costs are reasonable and comparable with those of a prudent service provider operating efficiently in accordance with the Code.

14 Glossary

14.1 Definitions

Capitalised terms not otherwise defined in this Submission have the meaning given in the draft Access Arrangement or the Code.

2002 Final Decision means the final decision on the Second Access Arrangement issued by the Commission on 13 November 2002.

AA Information means the Access Arrangement Information (as defined in the Code) lodged by GasNet with the Regulator on or about the date of this Submission.

Act means the *Gas Pipelines Access (Victoria) Act* 1998 (Vic).

AER means the Australian Energy Regulator.

AER Compendium means *Compendium of Electricity Transmission Regulatory Guidelines* issued by the AER in August 2005.

ACG means the Allen Consulting Group.

AMDQ means Authorised MDQ under the MSO Rules.

Building Block Methodology means the revenue methodology described as the Cost of Service methodology as set out in clause 8.4 of the Code.

CAPM means the Capital Asset Pricing Model.

CCA means current cost accounting.

Code means the National Third Party Access Code for Natural Gas Pipeline Systems.

Commission means the Australian Competition and Consumer Commission.

Compressor Strategy means GasNet's Compressor Strategy 2006 to 2017 report which is attached as Attachment C to this Submission.

Current Tariff Model means the current cost allocation and tariff methodology used to calculate GasNet's Reference Tariffs for the Second Access Arrangement as described in GasNet's submission on the Second Access Arrangement and the Second Access Arrangement.

Description Reports means the reports contained in Schedule 2.

EGP means the Eastern Gas Pipeline operated by Alinta running from Longford, Victoria to Horsely Park, NSW.

EPA means the Environmental Protection Authority Victoria.

ESC means the Essential Services Commission.

First Access Arrangement Period means in relation to the PTS, the period commencing on 15 March 1999 and ending on 31 December 2002 and in relation to the WTS, the period commencing on 1 January 1999 and ending on 31 December 2002.

GasNet means, subject to sections 1.3 and 3.1 of this Submission, GasNet Australia (Operations) Pty Ltd ABN 65 083 009 278.

GasNet Group means GasNet Australia Limited and its Related Bodies Corporate ACN 096 457 868.

GasNet (NSW) means GasNet Australia (NSW) Pty Ltd ABN 14 079 136 413.

Gas Safety Act means the *Gas Safety Act* 2001 (Vic).

Gas Safety Regulations means the *Gas Safety (Gas Quality) Regulations* 1999 (Vic).

Interconnect Decision means the decision cited as ACCC, *Revisions to Access Arrangements for the Principal Transmission System - Final Decisions*, 28 April 2000.

Interconnect Pipeline means the Pipeline constructed by GasNet from Barnawartha in Victoria to Culcairn in New South Wales.

KPI means key performance indicator.

LNG means liquid natural gas.

Market has the meaning given in the MSO Rules.

MCE means the Ministerial Council on Energy.

MSO Rules has the meaning given in the *Gas Industry Act 2001* (Vic).

NDWG means the Network Development Working Group.

NPV means net present value.

New Tariff Model means the proposed cost allocation and tariff methodology used to calculate GasNet's Reference Tariffs for the Third Access Arrangement.

Principal Transmission System means the Gas Transmission System as defined in the Service Envelope Agreement.

PTS means the Principal Transmission System.

Reference Service means the service described in clause 3.2 of the Access Arrangement.

Regulator means the Relevant Regulator under the Code which is currently the Commission.

Regulatory Period means a respective access arrangement period.

Related Bodies Corporate is as defined in the Corporations Act 2001 (Cwlth)

SEAGas means the South East Australian gas pipeline.

Second Access Arrangement means the access arrangement (including any revisions) for the Second Access Arrangement Period.

Second Access Arrangement Period means the Access Arrangement Period commencing on 1 February 2003 and ending on 31 December 2007.

Service Envelope Agreement means the agreement of that name entered into between VENCorp, GasNet (NSW) and GasNet dated 2 November 2006.

Submission means this Access Arrangement Submission (and all Schedules and Attachments) in support of GasNet's Access Arrangement for the Third Access Arrangement Period.

SWP means the Pipelines in Southwest Victoria comprising the South West Link (from Lara near Geelong to Iona near Port Campbell), the Western System Link (from Iona to North Paaratte, both near Port Campbell), and associated facilities, including the Lara, Iona and Brooklyn city gates and the Iona compressor station.

Synergies means Synergies Economic Consulting.

Tariff Model means the cost allocation and tariff methodology used to calculate Reference Tariffs.

Tariffed Transmission Service means the availability of the PTS, as sourced by VENCorp through the Service Envelope Agreement.

Telfer Pipeline means the 450km Pipeline from Port Headland to the Telfer gold mine in Western Australia.

Terrorism Act means the *Terrorism (Community Protection) Act* 2003 (Vic).

Third Access Arrangement Period means the Access Arrangement Period for GasNet commencing on 1 January 2008 and ending on 31 December 2012.

Transmission Tariff means the provision of the Reference Tariff for the Reference Service associated with the Tariffed Transmission Service, calculated in accordance with the Access Arrangement.

VENCorp means Victorian Energy Networks Corporation.

VENCorp Access Arrangement means the Access Arrangement by VENCorp for the PTS.

VENCorp APR means the Gas Annual Planning Report for the forecast period 2007-2011 prepared by VENCorp and published in November 2006.

VENCorp Gas Quality Guidelines means the Gas Quality Guidelines version 7.3 prepared by VENCorp, dated November 2001 .

VENCorp System Security Guidelines means the System Security Guidelines version 5, prepared by VENCorp, dated 8 January 2003.

Victorian Safety Act means Victorian Electricity Safety Act 1998 (Vic).

WACC means weighted average cost of capital.

WUGS means the Western Underground Gas Storage located at Iona.

15 List of Schedules

Schedule 1 - Map of PTS

Schedule 2 - GasNet Description Reports

16 List of Attachments

This Submission is accompanied by a range of supporting material comprising the following attachments.

Attachment A - VENCorp Network Planning and Timing Reports

Attachment B - GasNet Network Report on Carisbrook
(Planning and Timing)

Attachment C - GasNet Compressor Strategy

Attachment D - GasNet Scope and Workload Changes Report

Attachment E - SAHA on asymmetric risks

Attachment F - Synergies WACC report