GasNet Australia Access Arrangement - Submission (Schedules)

Dated 27 March 2002

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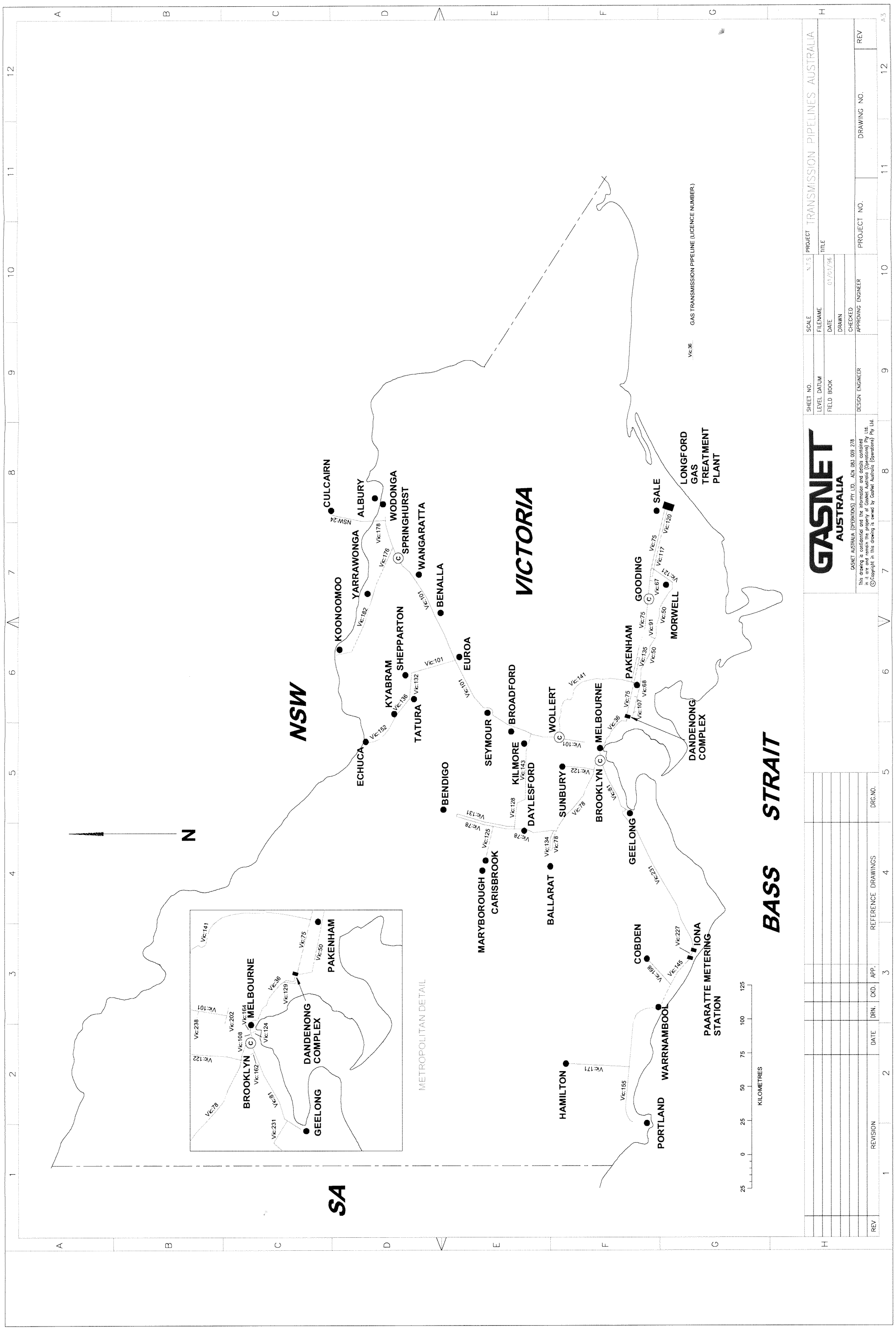


Schedule 2 - Regulatory framework

2.1 Current Access Arrangements

2.1.1 *Initial Access Arrangements*

On 3 November 1997, the Victorian Government submitted to the Commission, on behalf of TPA and TPAA (the state-owned predecessors of GasNet), proposed initial Access Arrangements and Access Arrangement Information for the Victorian natural gas transmission system for approval under the Victorian Code.

A suite of three separate Access Arrangements was submitted to the Commission for approval.

(a) The PTS Access Arrangement by TPA and TPAA.

(b) The WTS Access Arrangement by TPA and TPAA (as discussed in section 5.3 of the Submission, the PTS and WTS Access Arrangements are to be merged into a single Access Arrangement).

(c) The VENCorp Access Arrangement by VENCorp for the PTS.

Following public consultation and consideration by the Commission, the Commission released its Final Decision on 6 October 1998. Following submission of revised Access Arrangements, the Commission released its Final Approval on 16 December 1998 approving all three Access Arrangements.

The PTS Access Arrangement came into effect on 15 March 1999 (being the day the MSO Rules commenced) and operates until 31 December 2002. The WTS Access Arrangement came into effect on 1 January 1999 and operates until 31 December 2002.

For tariff calculation purposes, the PTS Access Arrangement and the WTS Access Arrangement utilise an asset base and a notional start date as at 1 January 1998.

The VENCorp Access Arrangement came into effect on 15 March 1999 and operates until 31 December 2002.

2.1.2 *Operating Lease Arrangement*

At the time of approval of the PTS and WTS Access Arrangements, TPAA, as owner of the PTS and WTS, leased the PTS and WTS under the Operating Lease Arrangement to TPA.

2.1.3 *GasNet acquisition*

On 2 June 1999, GasNet (which was then part of the GPU, Inc. group) acquired the business (including the assets and liabilities) of TPA and the Victorian business (including the assets and liabilities) of TPAA, including the PTS and WTS. In particular:

(a) under an Allocation Statement dated 2 June 1999 made under section 115C of the *Gas Industry Act 1994* (Vic):

(i) the property, rights and liabilities of TPA in the Operating Lease Arrangement (ie as lessee) were vested in GasNet; and

(ii) the property, rights and liabilities of TPAA in relation to pipelines situated in Victoria were vested in GasNet;

(b) the property, rights and liabilities of TPAA in pipelines situated in New South Wales remained with TPAA and were **not** allocated to GasNet; and

(c) GasNet acquired all of the shares in TPAA, with the result that TPAA (which is now called GasNet (NSW)) is a 100% owned subsidiary of GasNet.

2.1.4 *GasNet Australia float*

In December 2001, GPU, Inc. disposed of its interest in GasNet by a public offering of units in the GasNet Australia Trust, which is a managed investment scheme.

GasNet Australia Limited is the responsible entity for the GasNet Australia Trust. GasNet is a subsidiary of GasNet Australia Limited.

2.1.5 *Current status*

The effect of this structure is that:

(a) GasNet is:

(i) the owner of the WTS and the portion (approximately 95% by pipeline distance) of the PTS that is situated in Victoria (GasNet is the legal owner of the pipelines, as the Operating Lease Arrangement has "merged" in relation to pipelines situated in Victoria); and

(ii) the holder of the lessee's interest under the Operating Lease Arrangement in relation to the portion the PTS that is situated in New South Wales; and

(b) GasNet's subsidiary, GasNet (NSW), continues to own that part of the PTS situated in New South Wales and continues to lease it to GasNet under the remainder of the Operating Lease Arrangement.

As a result, GasNet makes this application as:

(a) the owner of the WTS;

(b) the owner of the PTS (other than the portion of the Interconnect Pipeline situated in New South Wales); and

(c) the lessee of the portion Interconnect Pipeline situated in New South Wales.

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

2.1.6 *Covered pipeline*

Under section 1.1 of the Code, the PTS and WTS were deemed to be Covered Pipelines by virtue of their inclusion in Schedule A of the Code.

Under section 10.3 of the Code:

(a) on acquiring the business of TPA and TPAA on 2 June 1999, GasNet became a Service Provider, which is defined in the Code as a person who owns (whether legally or equitably) or operates the whole or any part of a Pipeline; and

(b) the PTS and WTS Access Arrangements continued to apply to the PTS and WTS despite the change in Service Provider and bind GasNet in the same way that they bound TPA and TPAA immediately before GasNet acquired the PTS and WTS.

Finally, the PTS Access Arrangement continues to bind GasNet (NSW) in relation to the portion of the Interconnect Pipeline situated in New South Wales.

2.2 Revisions to Access Arrangements since 1998

2.2.1 *NSW Interconnect Assets*

Under clause 5.7.1(f) of the PTS Access Arrangement, the Interconnect Assets, which were commissioned in 1998 and 1999, are taken to be covered by the PTS Access Arrangement.

On 25 August 1999, GasNet made an application to the Commission, under the Extensions/Expansions Policy of the PTS Access Arrangement, to expand the PTS Capital Base in relation to, and amend the applicable Reference Tariffs for the use of, the PTS to take into account the Interconnect Assets. The application to revise the PTS Access Arrangement was approved by the Commission in April 2000 and took effect from 1 May 2000.

2.2.2 *SWP*

Under clause 5.7.1 of the PTS Access Arrangement, the SWP, which was commissioned in May 1999, is taken to be covered by the PTS Access Arrangement.

On 12 September 2000, GasNet submitted proposed revisions to the PTS Access Arrangement to include the cost of the SWP in the PTS Capital Base under the terms of its Extensions/Expansions Policy in the PTS Access Arrangement. The Commission did not approve that application. However, the Commission indicated that that decision was constrained by the particular terms of the Extensions/Expansions Policy in the PTS Access Arrangement and that the Commission would review the matter afresh as part of its consideration of the revisions to subsequent GasNet Access Arrangement.

2.3 Revisions process

Under section 2.28 of the Code, a Service Provider must submit proposed revisions to an Access Arrangement, together with an applicable Access Arrangement Information, by the date provided for in the immediately preceding Access Arrangement as the Revisions Submission Date.

The Revisions Submission Date for the PTS and WTS Access Arrangements is 31 March 2002.

Following the lodging of a proposed revised Access Arrangement, the Code requires the Commission to:

(a) inform interested parties that it has received the proposed revision to the Access Arrangement and Access Arrangement information;

(b) publish a notice in a national newspaper which describes the Covered Pipeline to which the proposed revisions to the Access Arrangement relate, state how copies of the proposed revisions can be obtained and specify a date by which submissions are required;

(c) after considering submissions received, issue a draft decision which either proposes to approve the revisions to the Access Arrangement or proposes not to approve the Access Arrangement and, if the latter is proposed, state the amendments or nature of amendments required to be made to the revisions in order for them to be approved; and

(d) after considering any additional submissions, issue a final decision which:

    (i) approves the revisions to the Access Arrangement; or

    (ii) does not approve the revisions to the Access Arrangement and states the amendments (or the nature of the amendments) which would have to be made to the revisions in order to approve them and the date by which amended revision must be resubmitted; or

    (iii) approves the amended revisions to the Access Arrangement submitted by the Service Provider which incorporate the amendments specified in the draft decision.

2.4 Information provision

2.4.1 *Code requirements*

Section 2.28 of the Code requires a Service Provider to submit an Access Arrangement Information with its proposed Access Arrangement. This must contain such information to enable Users to understand the derivation of the elements in the proposed Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Code.

The Access Arrangement Information must include the information described in Attachment A to the Code.

2.4.2 *GasNet's proposal*

GasNet submitted its proposed AA Information in conjunction with its proposed Access Arrangement.

Consistent with the allocation of responsibilities between GasNet and VENCorp, GasNet has submitted AA Information in relation to the relevant categories of information in Attachment A of the Code, except information in relation to the total number of customers in each pricing zone, service or category of asset.

As VENCorp has the direct relationship with Users of GNS, it is appropriate for VENCorp to provide this information. GasNet understands that VENCorp have incorporated this data into their Access Arrangement Information.

Under section 2.8 of the Code, information included in the AA Information may be categorised or aggregated to the extent necessary to ensure the disclosure does not unduly harm the legitimate business interests of the Service Provider or a User or Prospective User.

In the Final Decision, the Commission indicated that the Code did not require a level of disaggregation to replicate the calculation of the tariffs. The Commission stated that:

> "*the Commission does not believe that data to this level of disaggregation is required under the Victorian Access Code as it only requires the interested parties to 'understand the derivation of the elements in the proposed access arrangement' and not necessarily to be able to duplicate the tariff calculations.*"[1]

GasNet has not provided information in relation to the allocation of costs between its regulated and unregulated activities. Unregulated activity costs are commercially sensitive and confidential to GasNet. However, GasNet has provided the allocation model to the Commission on a confidential basis.

GasNet submits that there is sufficient information in the AA Information to enable Users and Prospective Users to understand the derivation of the elements in the Access Arrangement. There is also sufficient information to enable them to form an opinion as the compliance of the Access Arrangement with the provisions of the Code.

2.5 Victorian gas industry structure

2.5.1 *Industry restructure*

Historically, the Victorian natural gas market was supplied by GFCV, which was a State-owned, vertically-integrated monopoly.

In December 1994, GFCV was disaggregated into GTC, which was responsible for transmission activities, and GASCOR, which was responsible for the distribution and retailing of gas.

[1] Final Decision, *Victorian Gas Transmission*, 6 October 1998, p 66.

In 1997, the State undertook further restructuring of GTC and GASCOR, including:

(a) splitting GASCOR into three stapled distributors/retailers and a technical services company;

(b) transferring some of the functions of GTC to an independent wholesale gas market operator, VENCorp;

(c) constituting the remaining gas transmission functions of GTC in TPA and TPAA.

In late 1998 and early 1999, the State privatised the three distributors/retailers and TPA/TPAA (now GasNet).

As a result, GasNet owns the majority of Victoria's high-pressure gas transmission pipelines.

As discussed in section 3.3 of the Submission, access to the PTS for Users is governed by the MSO Rules, which establish a market carriage regime for the transportation of gas. VENCorp, a statutory company originally established under the *Gas Industry Act 1994* (Vic), is the system operator and the market operator under the MSO Rules. As such, it is responsible for conducting scheduling and other operational matters associated with the PTS and the operation of the spot market for gas created under the MSO Rules.

2.5.2 *Developments since 1998*

A number of important developments have occurred in the Victorian gas industry since 1998, including the following.

(a) In March 1999 the MSO Rules commenced operation, establishing the Victorian gas spot market and the market carriage gas transportation system.

(b) Duke Energy has constructed and is now operating the EGP, which transports gas from the Esso/BHP Billiton production facility at Longford to the NSW gas market (the EGP also delivers gas to Bairnsdale in Victoria).

(c) A number of parties have announced that they are investigating the construction of possible new transmission pipelines between Victoria and South Australia and Victoria and Tasmania.

(d) TXU has acquired and now operates the WUGS facilities, in relation to which TXU injects and withdraws gas from the PTS at Iona.

(e) Coastal Energy has developed the Wimmera pipeline, the primary flows of which involve taking withdrawals of gas from the PTS and transporting them to load centres in the Wimmera district of North-West Victoria.

(f) GasNet and APT have each constructed extensions to the PTS and the Moomba-Sydney Pipeline (respectively), so as to establish an interconnection between the two systems (the Interconnect Pipeline) (the regulatory treatment of GasNet's component of this interconnector is discussed in section 2.2 of this Schedule).

(g) GasNet has completed the SWP, which connects the WTS to the PTS.

(h) Envestra has developed the Mildura Pipeline, which delivers gas from South Australia into the Mildura area.

2.6 Regulatory framework

The main legislation and other instruments regulating access to the Victorian gas transmission system are:

(a) the Code, under which Service Providers are required to submit Access Arrangements to the Commission for approval;

(b) the *Gas Pipelines Access (Victoria) Act 1998* (Vic) and mirror legislation in other jurisdictions;

(c) the *Gas Industry Act 2001* (Vic);[2]

(d) the MSO Rules; and

(e) the Tariff Order.

Prior to commencement of the Code, access to gas pipelines in Victoria was governed by the Victorian Code. The current Access Arrangements were approved by the Commission under the Victorian Code.

The Tariff Order is a Victorian Order in Council under the *Gas Industry Act 1994* (Vic) which regulates, amongst other things, gas transmission tariffs for the regulatory period from 1 January 1999 to 31 December 2002. This timing is consistent with the Revisions Commencement Date of 1 January 2003 in the PTS and WTS Access Arrangements.

As part of its review of the proposed revisions to the current Access Arrangements, the Commission will determine the price control arrangements which will apply to transmission tariffs for the Second Access Arrangement Period. The Tariff Order guides the determination by the Commission for the regulation of tariffs in the subsequent regulatory period by establishing a set of Fixed Principles (see section 2.11 of this Schedule).

2.7 The Code

The Code commenced operation in Victoria in 1999 and, subject to the qualifications discussed in section 2.8 of this Schedule, replaced the earlier Victorian Code.

The objective of the Code is to establish a framework for third party access to natural gas transmission pipelines that:

[2] This replaces the *Gas Industry Act 1994* (Vic), which is now called the *Gas Industry (Residual Provisions) Act 1994* (Vic).

(a) facilitates the development and operation of a national market for natural gas;

(b) prevents abuse of monopoly power;

(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders;

(d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users; and

(e) provides for the resolution of disputes.

Under the Code an owner or operator of a Covered Pipeline is required to lodge an Access Arrangement with the relevant regulator. The Access Arrangement is designed to allow the owner or operator to develop its own tariffs and other terms and conditions under which Users can obtain access, subject to the requirements of the Code.

2.8 Status of the Victorian Code

2.8.1 *Code prevails over Victorian Code*

The current PTS and WTS Access Arrangements were approved under the Victorian Code. However, this submission proceeds on the basis that the Code, rather than the Victorian Code, is now applicable. This is because:

(a) section 24A(3) of the *Gas Pipelines Access (Victoria) Act 1998* (Vic) states that the Victorian Code will apply to a relevant Access Arrangement "until its first review under section 2 of the new Access Code";

(b) section 24A(7) of that Act defines "new Access Code" as the Code, and defines "first review" of an Access Arrangement as the date approved by the Commission as the "revisions commencement date for the purposes of the Access Arrangement";

(c) the Code in section 3.17(b) requires that a "revisions commencement date" be contained in an Access Arrangement; and

(d) the PTS and WTS Access Arrangement state that the "revisions commencement date" is 1 January 2003.

2.8.2 *Supporting arguments*

GasNet submits that this interpretation is supported by an examination of the surrounding context.

(a) This approach is suggested by the words of the transitional rules in Section 24A, which attach to an Access Arrangement rather than a pipeline or a Service Provider.

(b) This appears to be the policy objective of the transitional rules, ie that the initial Access Arrangement, which was approved under the

Victorian Code, should be regulated under that code, while the 2003 Access Arrangement should be governed by the Code.

(c) An objective of the transitional rules appears to be to ensure that, as the current access arrangements were approved under sections 3 and 8 of the Victorian Code, any revisions to the Access Arrangement would also be made under sections 3 and 8 of the Victorian Code. That is, the purpose of the transitional provisions was to ensure consistency during the initial access arrangement period, rather than to affect the 2003 Access Arrangement.

(d) If the Victorian Code provisions did govern the approval of the 2003 Access Arrangement, then this would produce the curious result that the 2003 Access Arrangement would be approved under the Victorian Code provisions, while any subsequent intra-period revisions (i.e. prior to 2008) would be approved under the (slightly different) Code provisions.

2.9 MSO Rules

2.9.1 *Function*

The functions of the MSO Rules include:

(a) the establishment of the Victorian Gas Spot Market; and

(b) the establishment of the market carriage gas transportation system for Users of the PTS.

The nature and operation of the market carriage system are described in more detail in section 3.3 of the Submission.

2.9.2 *Status of the MSO Rules*

The MSO Rules were made under section 48N of the *Gas Industry Act 1994* (Vic).

Section 13 of the *Gas Industry Legislation (Miscellaneous Amendments) Act 2001* (Vic) repealed Part 4A of the *Gas Industry Act 1994* (Vic), which included section 48N.

However the MSO Rules were specifically preserved under clause 17 of Schedule 5 to the *Gas Industry (Residual Provisions) Act 1994* (Vic). Schedule 5 to the *Gas Industry (Residual Provisions) Act 1994* was inserted by section 24 of the *Gas Industry Legislation (Miscellaneous Amendments) Act 2001*. Clause 17 of Schedule 5 reads as follows:

> "*17. MSO Rules -- Order under section 48N*
>
> *The Order made under section 48N of the old Act on 2 February 1999 as in effect immediately before the commencement of this clause continues in effect and may be amended or revoked in accordance with section 52 of the* Gas Industry Act 2001."

The MSO Rules therefore continue to exist and, by virtue of section 52(1) of the *Gas Industry Act 2001*, cannot be amended except in accordance with section 52 of the *Gas Industry Act 2001*.

2.10 Tariff Order

2.10.1 *Functions*

The functions of the Tariff Order include:

(a) regulating the pricing of tariffed services and excluded services provided by certain persons within the Victorian gas industry; and

(b) providing guidance to the relevant Regulator for the making of a price determination to regulate transmission tariffs and distribution tariffs for the Access Arrangement Period from 1 January 2003.

2.10.2 *Status of the Tariff Order*

The Tariff Order was made under section 48A of the *Gas Industry Act 1994* (Vic).

Section 13 of the *Gas Industry Legislation (Miscellaneous Amendments) Act 2001* (Vic) repealed Part 4A of the *Gas Industry Act 1994* (Vic), which included section 48A.

However the Tariff Order was specifically preserved under clause 11 of Schedule 5 to the *Gas Industry (Residual Provisions) Act 1994* (Vic). Schedule 5 to the *Gas Industry (Residual Provisions) Act 1994* was inserted by section 24 of the *Gas Industry Legislation (Miscellaneous Amendments) Act 2001*. Clause 11 of Schedule 5 reads as follows:

> *"11. Tariff Orders*
>
> *(1) The Victorian Gas Industry Tariff Order published in the Government Gazette on 17 December 1998, as in effect immediately before the commencement of this clause, continues in effect and may be amended or revoked in accordance with section 20 of the* Gas Industry Act 2001.*"*

The Tariff Order therefore continues to exist and, by virtue of section 20(1) of the *Gas Industry Act 2001*, cannot be amended except in accordance with section 20 of the *Gas Industry Act 2001*. The Tariff Order regulates gas transmission tariffs for the regulatory period from 1 January 1999 to 31 December 2002.

2.10.3 *Inconsistencies between the Tariff Order and the Access Code*

The regulatory regime recognises that the Tariff Order has a dual existence - as an independent Order and as a record of the Reference Tariffs and other matters approved by the Regulators as part of an Access Arrangement.

Recognising the possible tension between these roles, section 20(6) of the *Gas Industry Act 2001* deals with any inconsistency between the provisions of the Tariff Order and any arrangements approved under the Access Code. It replicates the former section 48A(5) of the *Gas Industry Act 1994* and reads as follows:

> *"If the provisions of a Tariff Order relating to charges for connection to, and the use of, any distribution pipeline or transmission pipeline are inconsistent with charges specified in access arrangements approved under the Access Code, the provisions do not apply to the extent of the inconsistency."*

In the *Gas Industry Act 2001*:

(a) "Tariff Order" is defined to include the tariff order published in the Victorian Government Gazette on 17 December 1998; and

(b) "Access Code" is defined to mean the Code.

2.11 Fixed principles

2.11.1 *Tariff Order provisions*

Clause 9.2(a) of the Tariff Order[3] sets out eight fixed principles which are to be applied by the Commission to "decide price regulation arrangements for the subsequent Access Arrangement period". The fixed principles provide part of the framework of the Reference Tariff Policy for the revised Access Arrangement.

The matters provided for in the Tariff Order can be divided into the following categories.

(a) Prescribed use of the CPI - X regulation approach with a fixed value of X for the revised Access Arrangement Period.

(b) The calculation of the Capital Base for the revised Access Arrangement Period.

(c) Incentive policies in relation to the creation of benefits and the sharing of those benefits across the system and over time.

(d) Use of the KT formula in the initial year of the revised Access Arrangement period.

It can be seen that there is some duplication of scope between the Code and the Tariff Order fixed principles, particularly in relation to the use of the CPI - X approach and the calculation of the Capital Base. This is discussed further in section 5.2.4 of the Submission.

2.11.2 *Access Arrangement provisions*

The PTS Access Arrangement also recognises the role of the Fixed Principles in the 2003 Access Arrangement review. Clause 5.3.6 of the PTS Access Arrangement states that:

[3] The full text of clause 9.2(a) of the Tariff Order is set out in Annexure 1 of this Submission.

"A *Fixed Principle* is an element of the *Reference Tariff Policy* which cannot be changed when the *Service Provider* submits reviews to an Access Arrangement, without the agreement of the *Service Provider*. The *Fixed Principles* applying to this Access Arrangement are set out in clause 9.2(a) of the *Tariff Order*.

The *Fixed Principles* in clause 9.2(a) of the *Tariff Order* can not be changed at the 1 January 2003 review of *Reference Tariffs*, and will apply for the duration of the *subsequent Access Arrangement period*, which is 5 years."

2.11.3 *Status of the Fixed Principles*

In an Access Arrangement, the Fixed Principles are the Reference Tariff principles that are not subject to periodic review. Fixed Principles are governed by section 8.47 of the Code, which provides that:

> *The Reference Tariff Policy may provide that certain principles are fixed for a specified period and are not subject to change when a Service Provider submits reviews to an Access Arrangement without the agreement of the Service Provider. A Fixed Principle is an element of the Reference Tariff Policy that cannot be changed without the agreement of the Service Provider ("**Fixed Principle**"). The period during which the Fixed Principle may not be changed is the Fixed Period ("**Fixed Period**").*

GasNet submits that the purpose of the Fixed Principles is to provide a degree of regulatory certainty for the regulated entity in relation to subsequent Access Arrangement Periods. For example, it would be open to the Regulator to "lock in" an incentive mechanism to apply in a subsequent Access Arrangement Period. This would give the regulated entity comfort that it could act in reliance on that incentive mechanism.

As discussed above, under the PTS Access Arrangement, the Fixed Principles found expression in the Tariff Order. The extract from clause 5.3.6 of the PTS Access Arrangement above indicates that the provisions in clause 9.2(a) of the Tariff Order were intended to apply as Fixed Principles under the Code rather than as independent regulatory constraints implied by law. Therefore, clause 9.2(a) of the Tariff Order is relevant only to the extent that it is incorporated into the Access Arrangement and is consistent with the Code. This is supported by section 20(6) of the *Gas Industry Act 2001*, which provides that in the event of an inconsistency between the Tariff Order and an Access Arrangement, the Access Arrangement is to prevail[4].

On this basis, GasNet submits that the ordinary provisions of the Code governed the Fixed Principles for the purposes of the 2003 Access Arrangement review. In particular, if GasNet agrees, then the Commission may depart from a Fixed Principle in approving the Access Arrangement revisions. This is not altered by the fact that the Fixed Principles are located in the Tariff Order.

[4] See section 2.10.3 of this Schedule.

As discussed in section 5.2.4 of the Submission, GasNet believes the Fixed Principles may inadvertently pose a potential constraint on GasNet’s proposals for the 2003 Access Arrangement review. In particular, the requirement to adjust the capital base to take account of additions and disposals of assets “in the ordinary course of business” may, if interpreted narrowly, restrict GasNet’s ability to include all of its New Facilities Investment in the Capital Base. GasNet is proposing revisions which may be inconsistent with this Fixed Principle. To the extent that these revisions are inconsistent with the Fixed Principle, and assuming the Commission is prepared to approve the revisions, GasNet agrees under section 8.47 of the Code to depart from those Fixed Principles.

Schedule 3 - SWP

3.1 Background

GasNet has previously sought to include the SWP in the Capital Base of the current Access Arrangement.[5] In its Final Decision regarding the revision of the current Access Arrangement to incorporate the SWP in the PTS asset base, in which it determined that the SWP would not at that stage be included in the Capital Base. The Commission indicated that GasNet should "submit its amended roll-in proposal at the time of the scheduled review of the Access Arrangement in 2002"[6].

The main reason expressed by the Commission for not allowing the SWP to be included in the Capital Base at the time was that "insufficient operational history currently exists to provide a sound basis for assessing GasNet's claims" as made in its submission[7].

GasNet believes that the amount of operational history of the SWP which can now be drawn upon provides a sufficiently sound basis for assessing the application to include the SWP in the Capital Base as a New Facilities Investment. In addition, GasNet considers that there have been a number of significant developments in the gas industry both in Victoria and interstate which provide a further justification for the inclusion of the SWP in the Capital Base as New Facilities Investment.

3.2 Which test applies?

A threshold issue is the identification of the appropriate test to be applied to determine whether the SWP should be included in the Capital Base. GasNet submits that the correct test is contained in sections 8.15 and 8.16 of the Code, which deal with the means by which the Capital Base for a Covered Pipeline may be increased from the commencement of a new Access Arrangement Period to recognise additional capital costs incurred in construction the New Facilities for the purposes of providing Services.

This conclusion is based mainly on a contextual reading of the criteria, in particular, section 8.15 of the Code states that the Capital Base for a Covered Pipeline may be increased *from the commencement of a new Access Arrangement Period* to recognise the capital costs of New Facilities Investment.

In addition, GasNet submits that, in assessing the SWP under sections 8.15 and 8.16 of the Code, the Commission should take into account the entire GasNet system. Assuming the preferred treatment of the WTS, this would include the PTS and the WTS.

However, there are a number of alternative tests which GasNet could apply.

[5] GPU GasNet Pty Ltd, *Application for Revision to Access Arrangement by GasNet Pty Ltd for the Principal Transmission System SWP* (11 September 2000).

[6] ACCC, *SWP Revision Decision* (Final, 2001), p 67.

[7] ACCC, *SWP Revision Decision* (Final, 2001), p 67.

First, it might be argued (GasNet submits, incorrectly) that the Extensions/Expansions Policy contained in GasNet's Access Arrangement is the appropriate test to apply. GasNet submits that the Extensions/Expansions Policy applies to intra-period revisions only. The appropriate test to apply at the commencement of a new Access Arrangement period is the test set out in section 8.16 of the Code.

However, if the Commission forms the view that the Extensions/Expansions Policy applies to the SWP, then GasNet submits that it is open to the Commission to consider and approve the revisions to GasNet's Extensions/Expansions Policy (see section 10.8 of the Submission) and the application to include the SWP in the Capital Base under a single process. If this approach is accepted by the Commission, then the SWP will be considered under GasNet's new Extension/Expansion Policy. The new policy provides that all extensions and expansions be assessed under section 8.16 of the Code.

Another approach might be to treat the SWP as a "new pipeline" under section 8.12 of the Code. This is discussed in greater detail in section 3.10 of this Schedule.

3.3 Description of the SWP

The SWP connects the PTS at Lara with the WTS at North Paaratte. It consists of the Lara-Iona pipeline ("South West Link"), the Iona-North Paaratte Pipeline ("Western System Link"), and the associated facilities.

The South West Link was commissioned in June 1999. It is a 500 millimetre diameter gas transmission pipeline with a length of approximately 144 kilometres. It connects the PTS at Lara with Iona (near Port Campbell), the site of the WUGS Facility. Associated pressure and flow control regulators at Lara and Brooklyn are necessary for the operation of the South West Link. The Brooklyn regulator, although not connected to the pipeline, is essential to the functionality of the South West Link.

The Western Link was also commissioned in June 1999. It is a 150 millimetre diameter gas transmission pipeline with a length of approximately 8 kilometres. It connects the South West Link at Iona with the Western Transmission System at North Paaratte. It is associated with a regulator and a small compressor station both at Iona.

The SWP was built under an accelerated timetable in response to the Longford fire and explosion. However, construction of the SWP was contemplated well in advance of the Longford emergency. The main reason it was originally contemplated for construction was to boost available gas supplies on the PTS during periods of peak demand. In particular, it was required to provide the link between the WUGS Facility and the PTS.

The total construction costs for the SWP were $82.8 million. However, the Victorian Government compensated GasNet for an amount of $7.3 million to cover additional costs incurred due to the accelerated timetable. GasNet proposes that this amount be deducted from the total construction cost and that, for the purposes of the Code, the construction cost of the SWP is $75.5 million.

3.4 Current status of SWP

GasNet submits that the current status of the SWP is as follows.

(a) The SWP is a Covered Pipeline by virtue of clause 5.7.1(a) of the PTS Access Arrangement.

(b) Pursuant to clause 5.7.2(b)(2)(C) of the PTS Access Arrangement, the amount representing the cost of the SWP has been included in the Speculative Investment Fund.

(c) Consistent with clause 5.3.4(b) of the PTS Access Arrangement, the amount of the Speculative Investment Fund includes an allowance for interest calculated on a compounded basis at the risk adjusted rate of return. As a result, the cumulative amount relating to the SWP will be $106.9 million as at 1 January 2003.

(d) For the reasons discussed below, the SWP will, from 1 January 2003, satisfy the requirements of section 8.16 of the Code and therefore the cumulative amount of the Speculative Investment Fund relating to the SWP may be added to the Capital Base from that date. However, GasNet recognises that the cumulative amount relating to the SWP is subject to the prudency test in section 8.16(a) of the Code. On this basis, GasNet proposes that the prudent amount to be attributed to the SWP is the original cost escalated to reflect inflation. This amounts to $85.0 million.

3.5 Code Requirements

Section 8.15 of the Code allows for the capital cost of the New Facilities Investment to be incorporated into the Capital Base at the start of a new Access Arrangement Period in recognition of costs incurred in the provision of Services. Section 8.16 of the Code sets out the tests which apply to determine whether the Capital Base may be increased by the amount of the capital costs incurred in the New Facilities Investment.

As a preliminary issue, it must first be established that the investment is prudent. That is, the investment must 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.

In addition, the New Facilities Investment must meet one of the following conditions (section 8.16(b) of the Code).

(a) The Anticipated Incremental Revenue generated by the new facility exceeds the New Facilities Investment (the “economic feasibility test”).

(b) The Commission is satisfied that the new facility generates system wide benefits that justify a higher reference tariff for all Users.

(c) The new facility is necessary to maintain the safety, integrity or contracted capacity of Services.

3.6 Prudent investment test

As noted above, the SWP must satisfy the prudent investment test in section 8.16(a) of the Code in order to be included in the GNS Capital Base. Section 8.16(a) of the Code provides that the investment must not exceed that which would be invested by a prudent service provider acting efficiently and in accordance with accepted good industry practice.

Section 8.17 of the Code sets out the factors that the Commission must take into account when applying the prudency test. Under section 8.17(a) of the Code the Commission must consider whether the SWP exhibits economies of scale or scope and increments in which capacity can be added. It must also consider section 8.17(b) of the Code which notes that the objective of achieving the lowest sustainable cost of delivering services over a reasonable time may require the installation of a new facility with sufficient capacity to meet forecast sales over that timeframe.

In its final decision regarding the revision of the PTS Access Arrangement to incorporate the SWP in the PTS Capital Base, the Commission accepted that the investment in the SWP was prudent in a technical and engineering sense. The Commission stated that:

> *GPU GasNet's investment in the South West Pipeline appears to be prudent in a technical and engineering sense. Its capacity, which matches that of the WUGS facility, is appropriate for its function. Its construction costs were reasonable taking into account its accelerated development and construction timetable and the Government's contribution.*[8]

The Commission also considered that the investment in the SWP met the criteria set out in section 8.17 of the Code.[9]

The Commission considered a range of criteria in its assessment of the prudency of the SWP investment. These criteria included:

(a) the need for additional system capacity to meet anticipated demand;

(b) the rationale for constructing the SWP;

(c) system planning for the winter of 1999;

(d) the on-going role and benefits of the SWP; and

(e) alternative technical solutions, such as demand management.

In adopting this broader interpretation of the prudency test, the Commission considered whether the SWP was prudent to achieve the additional system capacity it has made available. The Commission concluded that this would only be the case if the approach taken to achieve the additional system capacity also generated substantial system wide benefits.[10]

[8] ACCC, *SWP Revision Decision* (Final, 2001), p vi.

[9] ACCC, *SWP Revision Decision* (Final, 2001), p 36.

[10] ACCC, *SWP Revision Decision* (Final, 2001), p 37

GasNet submits that the prudency test should have an independent operation from the system wide benefits test. The appropriate test to apply is whether the pipeline is prudent in a technical and engineering sense including whether the construction costs were reasonable.

To give the test a broader interpretation leads to a situation where a form of the system wide benefits test is applied twice leaving no independent operation for the prudency test. A broader interpretation would also preclude a pipeline from satisfying section 8.16 of the Code unless it passed both the system wide benefits and the economic feasibility test.

In addition, the application of a broader interpretation begs the question as to what timeframe the prudency should be assessed over. For example, would the Commission be required to consider prudency in the context of a single Access Arrangement Period or over a longer period, such as the life of the pipeline? GasNet submits that this illustrates that a broader interpretation was not intended.

Therefore, GasNet submits that a narrow interpretation of the prudency test should be adopted and that issues relating to the system wide benefits of the SWP should be considered separately. By applying this interpretation of the test, the Commission's consideration should be limited to whether the pipeline is prudent in a technical and engineering sense. This is consistent with the criteria set out in section 8.17 of the Code.

GasNet submits that the SWP is prudent in a technical and engineering sense and that it meets the requirements of section 8.17 of the Code. As indicated above, in its final decision regarding the revision of the PTS Access Arrangement to include the SWP in the PTS Capital Base, the Commission accepted this proposition.

3.7 Economic feasibility test

3.7.1 *Regulatory Requirements*

In order to satisfy the economic feasibility test, it must be established that the Anticipated Incremental Revenue generated by the SWP exceeds the capital cost incurred in constructing the pipeline.

The term *Anticipated Incremental Revenue* is defined as the present value of anticipated future revenue from the sale of services at Prevailing Tariffs which would not have been generated without the incremental capacity.

The focus of the economic feasibility test is the anticipated revenue from the increased capacity. Capacity is defined as the measure of the potential of a pipeline to deliver a particular service between a receipt point and a delivery point.

The Prevailing Tariff for a Reference Service means the applicable Reference Tariff, and for any other Service means the Equivalent Tariff.

Equivalent Tariff means the tariff that is reasonably likely to have been set as the reference tariff had the service been a reference service.

3.7.2 *Application of the test to the SWP*

The economic feasibility test is difficult to apply to the SWP because the current tariff structure (ie zonal tariffs and the absence of contracted capacity) means that a degree of speculation is required to determine what the appropriate tariff for the SWP might be.

In applying the economic feasibility test contained in the Code, a preliminary question arises as to whether the SWP actually increases the capacity of the PTS. As indicated above, *Capacity* is defined by reference to the ability of the pipeline to deliver gas between a Receipt Point (the point at which custody of gas is transferred from a User to a Service Provider), and a Delivery Point (ie the point at which custody of the gas is transferred from a Service Provider to a User).

GasNet considers that the SWP does increase the capacity of the GNS. The pipeline can deliver at least 200 TJ from Iona into the GNS for delivery to withdrawal points on the GNS. Therefore, on a point to point aggregate basis, the ability of the system as a whole to deliver gas has been increased.

Another element of the economic feasibility test is the calculation of the Prevailing Tariff. The Code distinguishes between the Prevailing Tariff for a Reference Service and the Prevailing Tariff for a Service which is not a Reference Service. This raises the issue of whether the service associated with the SWP is part of the Reference Service. However, GasNet submits that, whichever route is adopted, the outcome is, in substance, the same.

A Reference Service is defined as a Service which is specified in an Access Arrangement and in respect of which a Reference Tariff has been specified in that Access Arrangement. The SWP is a Covered Pipeline under the PTS Access Arrangement. On this basis, the SWP may fall within the concept of a Reference Service. However, because of the current tariff structure, it is difficult to determine the applicable Reference Tariff for the SWP.

In order to give some meaning to the test, GasNet submits that it is appropriate to adopt a forward looking approach and consider what Reference Tariff would apply to the SWP from 1 January 2003 if the cost of the SWP is included in the Capital Base.

If the service associated with the SWP is **not** a Reference Service, then it is necessary to determine what the Equivalent Tariff would be. GasNet submits that this is likely to be the same as the Reference Tariff that would apply if the SWP were included in the Capital Base and treated as part of the Reference Service.

Therefore, whether or not the SWP forms part of the Reference Service, the economic feasibility test is applied by estimating (on a hypothetical basis) the Reference Tariff that would apply from 1 January 2003 if the SWP were included in the Capital Base.

Based on a stand-alone cost recovery tariff, GasNet has calculated a 10-day peak injection tariff of $4.0860/GJ. As discussed in Schedule 5.11, this assumes a revenue requirement levelised over 20 years, from which a tariff (levelised over the Second Access Arrangement Period) is calculated.

A question then arises as to what volumes of gas could GasNet reasonably expect would flow through the SWP if the tariff were set at that level.

There have been a number of developments in the last year which suggest that there will be sufficient demand for use of the SWP at this tariff. For example, two new major fields have been discovered in the Otway Basin off the coast of Port Campbell. These two fields, Thylacine and Geographe, contain large reserves of gas and are expected to start producing in 2006.[11] These developments could result in a further 60-100 TJ per day flowing west to east along the SWP all year round.

In addition, Santos has been producing from a number of onshore fields in the Otway Basin and four new fields are scheduled for production in 2002. It is expected that over the period 2002-2005, production will be gradually increased up to at least 55 TJ per day. Local production will continue to supply the WTS and will result in significant year round flow from the Port Campbell area to Melbourne.

The forecast volumes are shown in section 9.6 of the Submission. Applying the hypothetical Reference Tariffs to these forecast volumes (and assuming no decline in tariffs to match the depreciation of the asset), the NPV of this incremental revenue over the life of the pipeline is at least $89.7 million. This exceeds the (carried-forward escalated) cost of the SWP $85.0 million, and therefore the SWP passes the economic feasibility test.

3.8 System-wide benefits test

If the Commission concludes that the SWP does not pass the economic feasibility test, then, together and in the alternative, GasNet submits that the SWP passes the system-wide benefits test.

In order to satisfy the system-wide benefits test, the Regulator must be satisfied that a New Facility has system wide benefits which justify the approval of a higher reference tariff for all users.

The concept of “system-wide benefits” is not defined in the Code. However, GasNet considers that the there are two sources of system wide benefits for the SWP:

(a) enhanced system security and reliability; and

(b) enhanced competition.

The system-wide benefits of the SWP have been canvassed in GasNet’s previous application to include the SWP in the Capital Base. GasNet has reproduced the substance of these arguments in Annexure 1. This submission addresses the changes that have occurred since the original application was submitted.

[11] This is discussed in further detail in section 3.8.1 of this Schedule.

3.8.1 *Enhanced system security and reliability*

In the SWP Final Decision, the Commission stated that the SWP did have some potential to generate system wide benefits. However, the Commission indicated that the benefits were largely dependent on the level of reserves held in the WUGS facility and Otway Basin Gas developments.[12]

As discussed in section 3.7 of this Schedule, in the period since the Commission handed down its decision on the SWP, there have been a number of significant developments in the Otway Basin and off the South West coast of Victoria which have the potential to provide additional supplies of gas into the GNS via the SWP. GasNet submits that these new discoveries, in conjunction with the WUGS facility also have the potential to generate significant system security benefits.

One of the most important developments is the discovery of two large offshore fields, Geographe and Thylacine. Thylacine is located approximately 70 kilometres from the Victoria coast off Port Campbell. Geographe is located approximately 55 kilometres from the coast and 15 kilometres north of Thylacine. These fields contain large reserves of gas and are expected to start producing in 2006.

Reports indicate that the gas reserves in Thylacine may exceed 1 trillion cubic feet and that reserves in Geographe are in the order of 500 billion cubic feet.[13]

In addition, as discussed above, Santos has discovered numerous new onshore fields in the Otway Basin and has been producing for a number of years. Four of those fields are scheduled for production in 2002. GasNet expect their production to reach 50-60 TJ per day by 2003, with the possibility of further increases to 80 TJ per day by 2004.

The development of these fields will further enhance the on-going system security benefits of the SWP in that they have the potential to provide an additional source of gas in the event of an interruption of gas supply on other parts of the GNS.

3.8.2 *Competition Benefits*

In its 1998 authorisation determination on the MSO Rules, the ACCC identified lack of upstream competition as a significant issue for gas reform in Victoria. The Commission stated that:

> *"… the benefits of competition in Australian gas markets, including those associated with establishing rights of access to gas pipelines, will not be realised in the absence of effective upstream competition."*[14]

[12] ACCC, *SWP Revision Decision* (Final 2001), p vii

[13] Origin Energy, *Report for the quarter ended 30 June 2001 to the Australian Stock Exchange*.

[14] ACCC, Determination, *VENCorp authorisation application for Market and System Operations Rules*, 19 August 1998, 31.

One of measures identified by the Commission to facilitate competition between gas producers was the construction of new pipelines and links to new basins[15].

The competition benefits provided by the SWP were canvassed by GasNet in its original application to have the SWP included in the Capital Base.[16]

In the SWP Final Decision, the Commission recognised that the SWP had the potential to generate competition benefits, but that the extent of these competition benefits would depend on factors such as the level of usage of the WUGS facility and the extent of Otway Basin gas developments.[17]

Information of the level of usage of WUGS for the period 2000-2001 is contained in Schedule 7. The figures indicate that the SWP is already being used at half its capacity on the peak days.

The developments in the Otway Basin described above provide further evidence of the ability of the SWP to generate competition benefits to all Users of the GNS.

The SWP provides a means of delivering gas from the newly developed fields in the Otway Basin into the Victorian market and thus allows other producers to compete in the market against gas from Bass Strait. This further enhances competitive pressures on Victoria's primary gas producer, Esso/BHP Billiton and has significant value to all Victorian users with the obvious potential to reduce prices to consumers.

The presence of the SWP has acted to further stimulate exploration in the Otway Basin. The discovery of further onshore reserves of gas in the last year and continued exploration activity in the area are evidence of this. In the absence of a pipeline connection to Melbourne it is unlikely that a number of the smaller fields which are in the process of being developed would be viable.

The discovery of Thylacine and Geographe have the potential to provide a long term, secure and competitive supply of gas into the Victorian market. The SWP will provide a means of connecting the Victorian market to these new fields.

In addition to introducing competition for base load supply, the SWP facilitates competition for peak supply. That is, it allows for additional flows to compete to supply the market at times of peak demand, when the existing supply arrangements are more likely to be finely balanced.

The benefits that flow from the improved competition are difficult to quantify precisely. However, a useful perspective on the issue is obtained by comparing the annual revenue requirement of the SWP (as included in the Capital Base) with the total traded value of gas in Victoria each year. For example the annual revenue requirement associated with recovery over the

[15] ACCC, Determination, *VENCorp authorisation application for Market and System Operations Rules*, 19 August 1998, p 30.

[16] GasNet has reproduced the substance of these arguments in Annexure 1 of the submission.

[17] ACCC, *SWP Revision Decision* (Final, 2001), p vii

lifetime of the SWP of $8.5 million may be compared to an estimated annual traded gas of the order of $650 million or approximately 1.25%.

3.9 Aggregation

If the Commission forms the view that only a portion of the SWP passes each of the economic feasibility test and the system wide benefits test, then GasNet submits that the Code allows each of those portions to be aggregated and included in the Capital Base.

In its Final Decision on the inclusion of the SWP in the Capital Base, the Commission implied that the only obstacle to an aggregate roll-in was GasNet's access arrangement. The Commission stated that:

> *There is currently no provision in GPU GasNet's PTS access arrangement for part of an investment to be recovered pursuant to the economic feasibility test and for the remainder to be rolled-in under the system-wide benefits test.*[18]

As part of the revisions to the current Extension/Expansion Policy, all applications to include New Facilities Investment in the Capital Base will be considered under the relevant provisions of the Code (including sections 8.15 to 8.19 of the Code).

Section 8.18 of the Code provides that a Reference Tariff Policy may, at the discretion of the Service Provider, state that the Service Provider will undertake New Facilities Investment which does not satisfy the requirements of section 8.16 of the Code (**Speculative Investment**). Any part of the New Facilities Investment which does satisfy the requirements of section 8.16 of the Code may be included in the Capital Base.

As noted above, GasNet was unsuccessful in its application to have the SWP included in the Capital Base. As a result, the amount of New Facilities Investment representing the SWP is a Speculative Investment.

Under section 8.19 of the Code an amount in respect of the balance of the New Facilities Investment may be subsequently added to the Capital Base if,

> *at any time the type and volume of services provided using the increase in Capacity attributable to the New Facility change such that any part of the Speculative Investment Fund would then satisfy the requirements of section 8.16.*

Section 8.19 of the Code allows *any part* of the Speculative Investment Fund to be included in the Capital Base if it satisfies the requirements of section 8.16 of the Code. The use of the words *any part* suggest that different parts of the Speculative Investment Fund may be included in the Capital Base as long as the particular part satisfies one of the tests in section 8.16 of the Code.

Section 8.19 of the Code also requires that there be a change in the *type and volume of services* provided using the increase in Capacity, such that any part

[18] ACCC, *SWP Revision Decision* (Final, 2001), p 39.

of Speculative Investment Fund would satisfy one of the tests in section 8.16 of the Code.

The SWP no longer just provides a source of peaking gas but is also supplying baseload gas. Therefore, GasNet submits that there has been a change in the type of services provided by the SWP. In addition, there has been a change in the volume of services being provided by the SWP and, given the recent developments in the Otway Basin, the volume of services provided by the SWP is likely to further increase.

On this basis, GasNet submits that section 8.19 of the Code would allow part of the SWP to be included in the Capital Base under the economic feasibility test and the remaining part to be included in the Capital Base under the system wide benefits test.

3.10 An alternative approach - the SWP as a new pipeline

If the Commission concludes that the SWP does not pass the tests set out in section 8.15 and 8.16 of the Code, then in the alternative, GasNet submits that it is open to the Commission to treat the SWP as a "new pipeline" under section 8.12 of the Code.

By reason of the combination of the paragraphs (a) and (b) of clause 5.7.1 of the existing PTS Access Arrangement, the SWP was deemed to be an extension to the PTS. However, if GasNet had the opportunity to give the relevant notice under paragraph (c), it could have nominated that the SWP would not form part of that access arrangement.

The fact that the SWP may have been deemed an extension to the PTS during the current regulatory period, does not mean that it need be an extension to the PTS under the revised access agreement for the next regulatory period.

Section 2.4 of the Code provides that a Service Provider may voluntarily submit separate access arrangements for different parts of the Covered Pipeline so that the separate access arrangements apply to the whole of the Covered Pipeline. In such a case, each part of the pipeline that is the subject of an access arrangement will be treated as a separate Covered Pipeline for the purposes of the Code. Accordingly, there is no reason why GasNet could not voluntarily submit a separate access arrangement for the SWP to take effect from 1 January 2003.

If this were to occur, it may be that in order to identify the Capital Base of the SWP for the purposes of the Code (which has not occurred previously), the appropriate section of the Code to consider is section 8.12.

Section 8.12 of the Code provides that,

> *When a Reference Tariff is first proposed for a Reference Service provided by a Covered Pipeline that has come into existence after the commencement of the Code, the initial Capital Base for that Covered Pipeline is, subject to section 8.13, the actual capital cost of those assets at the time they first enter service. A new pipeline does not need to pass the tests described in section 8.16.*

Section 8.13 of the Code deals with the situation where the period between the time when the Covered Pipeline first enters service and the time when the reference tariff is proposed is such as reasonably to warrant adjustment to the actual capital cost in establishing the initial Capital Base.

For example, if the EGP were to become a Covered Pipeline under the Code at some later time, it would appear that sections 8.12 and 8.13 would be the appropriate sections to apply, notwithstanding the fact that the EGP would not be technically “new”. However, it would be “new” for the purposes of the Code.

By analogy, it could be argued the SWP is “new” for the purposes of the Code as it has not been included in the Capital Base, no Capital Base has been allocated to it for the purposes of the Code and no Reference Tariff has been determined in respect of it.

GasNet does not propose that the SWP be the subject of a separate access arrangement. However, GasNet does propose to merge the WTS and PTS pipeline into a single access arrangement. GasNet submits that the SWP could also be merged into the Access Arrangement, taking into account its Capital Base as determined by sections 8.12 and 8.13 of the Code.

Schedule 4 - Asymmetric Risks

4.1 Proposal

GasNet proposes to include in its cost of service an allowance reflecting a series of asymmetric risks that are not adequately reflected elsewhere in the Total Revenue.

In most cases, risks are dealt with through the CAPM. However, while the CAPM is intellectually appealing, it must be critically assessed with respect to the requirements of the Code. In particular, while the Code recognises the CAPM as a model for determining the Rate of Return, it does not recognise the CAPM as reflecting all of the costs associated with providing a service.

In particular, GasNet submits that while the CAPM is well accepted, the way it is applied by the Commission (and other regulators) contains a key characteristic which, if not addressed, would result in a decision that:

(a) prevents the Service Provider from recovering the efficient cost of delivering the relevant Services;

(b) fails to replicate the outcome of a competitive market; and

(c) is not commensurate with the risks involved in the relevant Services.

As discussed in section 6.14 of the Submission, consistency with the CAPM framework requires that, to the extent that they should be recognised, specific risks be factored into projected cashflows (as a pseudo opex) rather than the cost of capital.

4.2 Terminology

A threshold issue is appropriate terminology to be applied in relation to these risks. A range of terms has been used in regulatory circles (not all of which are interchangeable), including:

(a) non-systematic risks;

(b) specific risks;

(c) non-market risks;

(d) diversifiable risks;

(e) excluded events;

(f) unique risks; and

(g) biased events.

For the purposes of this submission, GasNet proposes to adopt the following expressions:

- **specific risks** means all risks that are not market-related (that is, they cannot be measured with respect to the financial market as a whole); and
- **asymmetric risks** means the subset of specific risks that are asymmetric in nature and for which an allowance should be made in the regulated cash flows.

4.3 Allowance for asymmetric risks

Section 8.4 of the Code requires that, under the Cost of Service Methodology, the Commission must calculate the Total Revenue so that *the Total Revenue is equal to the cost of providing all Services*.

The Cost of Service Methodology estimates the revenue requirement for a regulated entity by summing the various costs which are expected to be incurred over an Access Arrangement Period. These costs are principally the expected operating costs, taxation liabilities, and the return on and of capital. Under the CAPM, risks relating to a business are either regarded as diversifiable (and therefore excluded) or quantified by the CAPM theory of betas.

The question then arises as to whether (and how) specific risks (which are excluded from the CAPM) should be accommodated in Reference Tariffs.

A number of regulators have recognised that some specific risks may need to be reflected in regulated returns. For example, in the recent MAPS decision, the Commission acknowledged that specific risks should be addressed in regulated returns and that:

> *Consistency with the CAPM framework therefore requires that specific risks be factored into projected cash flows rather than the cost of capital.*[19]

Similarly, the ORG has observed that:

> *... while the events that could be characterised as giving rise to diversifiable risk do not reflect the cost of capital associated with an asset, they are not irrelevant. ... when designing price controls, it is necessary to generate stream of expected economic returns that is equal to the estimated cost of capital, taking into account all potential states of nature.*[20]

GasNet accepts that a number of specific risks should not be reflected in tariffs calculated using CAPM. However, GasNet submits that there are a number of specific risks that should be reflected in the Reference Tariffs. The key characteristics of these "allowable" risks are that:

- they are asymmetric (ie the possible negative outcomes are significantly larger than the possible positive outcomes);

[19] ACCC, *MAPS Gas Access Arrangement* (Final, 2001), p. 45.

[20] ORG, *Further Guidance to Gas Distributors*, December 2001, p 52.

- they are difficult (if not impossible) to insure against at commercial rates;
- they cannot be diversified away by investors because the counterparties to these risks are not public companies in which investors can invest; and
- 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 (ie the Total Revenue).

Put another way, individual companies are still subject to specific risks which, if not compensated for in the Cost of Service, would lead to a reduction in the value of the business below the depreciated value of the investment.

In this submission, GasNet refers to these risks as "asymmetric risks". GasNet has considered the risks that it faces in the Second Access Arrangement Period and submits that, on balance, there are a number of risks that meet this test of "asymmetric risks" and should be allowed for in the Reference Tariffs.[21]

Consistent with the Commission's comments in the MAPS decision, GasNet proposes a cash flow adjustment for the following asymmetric risks:

Asymmetric Risk	Allowance ($ p.a.)
Property related risks	20,000
Deductibles in current insurance arrangements	140,000
Credit risk	252,000
Terrorist threat	65,000
Risk of stranding	75,000
Other risks	200,000
Total	**752,000**

These asymmetric risks (together with GasNet's proposed cash flow adjustment) are discussed below. In many cases, GasNet submits that the appropriate measure of the cash flow allowance is as a quasi self-insurance premium. In those cases, GasNet has sought advice from Trowbridge as to an estimate of the self insurance cost.

4.4 Property related risks

Trowbridge has estimated the self-insurance cost of risks relating to pipeline corrosion risks and extortion and bomb threats.

(a) *Pipeline corrosion risks*

Gas pipelines are exposed to corrosion that may cause them to rupture possibly resulting in gas igniting. Third party claims are covered by

[21] There are a number of risks which GasNet has not included on the basis that they do not constitute "asymmetric risks" - see section 4.11 below.

existing insurance, however, property damage due to corrosion is excluded.

(b) *Bomb threat risks*

Insurance policies in this class of insurance are designed not only to indemnify the company for the exposure to a loss caused by the payment of a ransom or extortion, but also to pay for other related expenses and loss of earnings.

Trowbridge estimate that these costs amount to $20,000 per annum.

4.5 Deductibles in current insurance arrangements

GasNet has submitted to the Commission its proposals for the recovery of insurance costs As discussed in section 8.3.4 of this Submission, these proposals include an assumption that GasNet will maintain its current approach to insurance, including deductibles.

However, there are a number of situations where GasNet may seek to limit its insurance. In its report, Trowbridge identifies a number of reasons why a company might limit the extent of its insurance. These include where:

(a) the company believes the quoted insurance premium is in excess of the true insurance cost;

(b) the required insurance is not readily available (for example, asset stranding risk);

(c) the company has sufficient working capital to withstand the risks in question (for example, the risks within the insurance “deductible” limit);

(d) the company has accepted an attractive premium on a “standard” insurance policy which includes a range of exclusions, and the cost of “writing back” the exclusions exceeds the company’s perceived value of the excluded risks; and

(e) the insurer requires the company to bear a reasonable share of each claim to incentivise it to better manage its claims experience.

If a company is not offered a reasonable allowance for self-insurance in the Cost of Service, then that company will have a perverse incentive to over-insure, and include excessive insurance costs within the operating costs.

Similarly, the insurance cover is limited and GasNet is liable for any claims costs above the limit.

Trowbridge has estimated that these costs amount to $140,000 each year.

4.6 Credit risk

Trowbridge has estimated the self-insurance cost of credit risks as $252,000 per annum. These risks relate to:

(a) insurer's default risk (particularly in light of recent experience with insurance collapses such as HIH); and

(b) counterparty credit risk (GasNet is subject to private sector credit risks even though GasNet's revenue is sourced indirectly from these market participants through VENCorp).

4.7 Terrorist threat

Terrorist sabotage cannot be insured. However it is a potential liability as evidenced by recent threats against US utilities. Trowbridge has not attempted to quantify this risk. However, GasNet submits that a premium can be estimated. GasNet has assumed that the maximum value of assets that would be affected by terrorist threat is limited to the aboveground assets of the network only (approximately $140 million). Based on a one in a five hundred event causing damage to a single asset valued at $25 million, and considering the associated loss of revenues, the appropriate annual self-insurance cost is $65,000.

4.8 Risk of stranding

Transmission pipelines carry gas long distances from supply points to customers. They are at risk of new supply sources being developed, with the result that a market may be lost to a competing pipeline.

In addition, GasNet's Reference Tariff Policy provides that where an asset is redundant, it is to be removed from the Capital Base. This is unlike the situation of the Victorian gas distributors, in relation to which the ORG has indicated that the only redundancy risk is the risk of a whole of system redundancy.[22]

A case in point is the bypass threat to the GasNet WTS pipelines from the Iona-Adelaide pipeline. This pipeline is being developed to supply the South Australian market with gas from the off-shore Otway gas resources. This pipeline will pass towns already supplied by the GasNet system. In the case of the WTS, GasNet believes a prudent discount can be offered (see Schedule 5.16.4 of this Submission), but if this were not the case, then GasNet would have made a significant loss of profits (of the order of $1.0 million per annum if two towns had left the GasNet system).

This risk is concentrated on possible bypass of GasNet's laterals, since the risk to injection pipelines is treated by assessing an appropriate economic life. Similarly, the Metro hub is, like distribution pipelines, at lower risk of this form of bypass.

Based on a 1% probability of losing 5% of the lateral investment, GasNet estimates a reasonable premium as $75,000 /year.

[22] ORG, *Further Guidance to Gas Distributors*, December 2001, p 40.

4.9 Other risks

Trowbridge has considered a range of other risks which, while small in value individually, have a material impact as a whole. These include risks such as uplift liability and key person risk.

Trowbridge has estimated the annual cost associated with these risks is $200,000.

4.10 Risks not included

GasNet has made an assessment of the negative financial impact of asymmetric risks based on a detailed analysis of specific events. In principle it is possible that some asymmetric risks may have a positive financial impact. However GasNet believes that there are no substantive upsides that may be classified as asymmetric specific risks, except where the incentive-based regime has succeeded in generating real benefits.

The risks faced by GasNet may be classified as either revenue risks, or cost risks. Under the incentive based regime applying to GasNet, these risks relate to deviations of actual outcomes against the original forecasts from which the approved Total Revenue was derived.

The following is GasNet's analysis of risks which it has considered but concluded do not warrant specific treatment in the Reference Tariffs.

(a) *Revenue Risks*

The principal source of revenue risk is from fluctuations in gas volumes (credit risks have been discussed already as a self-insurance cost). GasNet can receive higher or lower profits to the extent that actual gas volumes exceed or fall short of the forecast used to derive the tariffs. These variations in volumes are largely outside the control of GasNet, and are equally likely to be positive as negative, assuming the original forecast was unbiased. As it happened, GasNet made significant losses against the original volume forecast, due to a range of factors. However, there is no reason to believe that the new forecast will be biased, and the ACCC will satisfy itself that this is the case. Hence GasNet does not believe that volume risk is asymmetric.

(b) *Cost Risks*

As with volume risks, GasNet can receive higher or lower profits depending on how the actual costs compare to the forecast costs. The operating costs and capital expenditure forecasts receive close scrutiny from the ACCC and the public. Hence provided the original forecasts are unbiased, the cost risk is not asymmetric.

However, it is sometimes claimed that the regulator lacks sufficient information to judge the fairness of an operating cost and capital expenditure forecast, and that the regulated company therefore has a potential upside. This issue is difficult to assess in general terms, however the following comments are relevant to the situation of GasNet.

(i) GasNet has exceeded its original capital expenditure forecast, and provided the required services in equivalent terms.

(ii) Capital expenditure on transmission pipelines can be assessed on a case-by-case basis, given the small number of major projects likely over a regulatory period.

(iii) Whilst GasNet has made efficiency gains in operating costs, there have been a number of extraordinary events which have been to GasNet's detriment, specifically:

(A) revenue losses and litigation costs arising from the Longford fire and explosion, and

(B) a $1.1 million blow-out in insurance costs applying over 2002.

(iv) Operating costs are only a small proportion of total costs.

(v) GasNet is a relatively simple business with no links to other transmission pipeline businesses or retailing functions.

Based on these considerations, GasNet believes that there is no reason to believe that a fair forecast of costs cannot be reached.

(c) *Incentives*

GasNet operates under an incentive-based regime, which is designed to reward GasNet for increasing gas volumes, and decreasing costs. These benefits are passed through to customers after each Access Arrangement period, subject to the agreed benefit sharing arrangements. To the extent that GasNet can achieve these benefits, both GasNet and customers will benefit.

GasNet believes that it is the intention of incentive-based regulation for the regulated company to keep a share of the financial benefits derived from the companies efforts. A share of these benefits is also kept by customers, leading to a win-win situation. It is not appropriate to classify these company gains, to the extent they occur, as balancing items against genuine downside costs as documented in this Submission.

(d) *Construction risk*

GasNet is exposed to ongoing asymmetric construction risk in relation to extensions and expansions.

GasNet submits that this risk is, by its nature, asymmetric. In particular, assuming efficient construction estimates, there is unlikely to be much room for cost savings, while there is no cap on cost increases. This applies even if the entity can secure a fixed price construction contract, as the contract price will reflect the contractor's estimate of this risk. From an investor's perspective, this risk is also asymmetric as another investment (such as a contractor) would only benefit to the extent the cost blow out represented profit, while the regulated entity suffers the detriment fully.

This asymmetry is accentuated by the Code, which provides that, in relation to covered Extensions and Expansions, the Capital Base will be increased to reflect the actual capital costs, subject to a prudency test. In other words, if GasNet achieves a lower capital cost, it does not enjoy any benefit, however, if GasNet suffers a cost blow-out, it is at risk of having its capital costs wound back by the Commission.

The Code appears to recognise an aspect of these risks, at least in relation to new pipelines. Section 8.12 of the Code provides that where a Reference Tariff is first proposed for a new pipeline, the initial Capital Base for the pipeline is the actual capital cost of those assets, rather than any regulatory valuation (whether based on ODRC or some other methodology). A new pipeline is not required to satisfy the prudency test which, if applied, could see the regulatory value set at a value below the actual cost. GasNet submits that the intention of the Code is to remove the construction risk from consideration (for example, by not imposing a prudency test). The effect of this discrepancy is illustrated by examining the SWP. If the SWP were established as a new pipeline (that is, constructed and owned by an alternative pipeline company to GasNet), then its Reference Tariffs would be based on its actual capital cost. However, if (as GasNet has assumed for the purposes of tariff modelling) it is included as part of the GNS, then its capital costs is subject to a prudency test.

However, GasNet has been unable to quantify with reasonable accuracy an allowance for this risk and, at this stage, does not propose to include any allowance.

(e) *Market development risk*

Similarly, GasNet is exposed to asymmetric risks in relation to uncertainties associated with developing and marketing the services to be provided by the asset.

These risks are asymmetric because if the service proves to be very successful, it is likely new entrants will enter the market thereby putting a ceiling on any super-profits. However, if the service proves to be a commercial failure, there is no floor below the possible losses. Therefore, the appropriate price for these services should be higher than the price derived from the application of the CAPM rate to the regulatory value of the asset.

However, GasNet has been unable to quantify with reasonable accuracy an allowance for this risk and, at this stage, does not propose to include any allowance.

Schedule 5 - Tariff Methodology

5.1 Background

Under the provisions of the Code for the sharing of responsibilities between the owner and operator of a transmission pipeline (section 10.2 of the Code), GasNet and VENCorp agreed in 1998 to separate between themselves the responsibility for the design, implementation and administration of the Reference Tariff. GasNet is responsible for the transmission tariff which recovers the costs to provide the transmission system for VENCorp to operate, and VENCorp is responsible for the VENCorp tariff which recovers the costs of operating the transmission system and managing the Victorian gas market.

This arrangement is given formal effect under the Service Envelope Agreement between GasNet and VENCorp. The Agreement recognises that VENCorp is the contracting party with Users, but it delegates to GasNet the responsibility to design and administer the transmission tariff.

GasNet and VENCorp will continue with this arrangement for the Second Access Arrangement Period. As such, GasNet has reviewed the existing tariff in the light of practical experience.

In summary, GasNet has not made significant modifications to the current tariff design. This is because:

(a) the unique circumstances of the Victorian market carriage system constrain the ability to vary the tariff design principles significantly; and

(b) there are benefits in maintaining consistency in tariffs between periods.

However GasNet has addressed some anomalies in the original cost allocation procedures and some areas where the tariff can be considerably simplified without detriment to existing Users. In addition, GasNet has been approached by a number of market participants who have identified areas where a bypass pipeline would be more economical than the existing transmission tariff, which suggests that some aspects of the existing tariff design are not efficient.

5.2 Unique Circumstances

GasNet operates under the unique Market Carriage model. All other transmission pipelines in Australia operate under a contract carriage model. This has a number of important implications.

(a) GasNet cannot secure its revenues under take-or-pay contracts. Therefore, GasNet tariffs must be levied on actual flows on the system.

(b) The setting of the tariffs must be based on a forecast of the gas flow paths. However, since GasNet operates under an incentive-based regulatory model the tariffs, once set, cannot be altered to suit changed circumstances.

(c) To the extent that the *actual* flow paths differ from the forecast, the cost allocation to that User will not be as was intended. In contrast, under a Contract Carriage model, the User contracts for capacity in a pipeline over a given flow path, and its charge is always related to that pre-specified path.

This last point suggests that it is inappropriate to require too rigid an application of cost-reflective tariff principles to the GasNet tariff. A cost allocation process done in hindsight after actual flows are known will differ from that which is currently being forecast. This further suggests that the tariff design can only be a compromise between a range of conflicting principles.

5.3 Experience with the Existing Tariff

The following issues and concerns have arisen from experience with the existing tariff design:

(a) some Users see the tariff design as unnecessarily complex, given the low level of the transmission tariff relative to distribution charges and gas costs (the transmission tariffs account for approximately 5-10% of the delivered cost of gas);

(b) the complexity leads to high costs to administer the tariff;

(c) Users cannot respond to the price signal inherent in withdrawal tariffs based on five peak day charges, and cannot know in advance what their charges might be[23];

(d) Users have found that withdrawal tariffs based on five peak day (Tariff-D) and winter charges (Tariff-V) can significantly increase the complexities of customer churn within a fully competitive retail market; and

(e) a number of bypass pipeline opportunities have been identified, which indicate that the tariff design is not efficient in certain areas.

However, to date no concerns have arisen with respect to the use of peak day injection tariffs, or with the extent and coverage of the tariff zones.

GasNet has reviewed a number of alternative tariff models, and has concluded that a significant change in methodology is not justifiable as any change would involve as many negative as positive features. An attempt has been made to address the concerns identified above, which have the effect of making relatively minor modifications to the design. These are discussed below in the section on Tariff Design.

[23] For example, one User who flowed gas to NSW during the winter in response to a supply shortfall, found after the event, that the flows defined the peaks leading to unexpectedly high charges.

5.4 Tariff Design Criteria

The Code is relatively non prescriptive as to how a tariff should be designed and recognises that any tariff methodology involves a careful balancing between economically efficient cost allocation and the practical requirements of commercial utility.

In addition to the overarching principle set out in section 2.24, the Code includes a number of specific provisions dealing with tariff design.

(a) Section 8.1(e) provides that the Reference Tariff should be designed with a view to achieving efficiency in the level and structure of the Reference Tariff.

(b) Section 8.38(b) provides that *to the maximum extent that is commercially and technically reasonable*, a Reference Tariff should be designed to recover a share of the Total Revenue that reflects costs incurred that are attributable to providing the relevant Reference Service jointly with other Services, with this share to be determined in accordance with the methodology that meets the objectives in section 8.1 and is otherwise fair and reasonable (emphasis added).

(c) Section 8.42 of the Code provides that a Reference Tariff should, *to the maximum extent that is technically and commercially reasonable*, be designed so that a particular User's share of the portion of Total Revenue to be recovered from a Reference Service is consistent with the principles described in section 8.38 of the Code (emphasis added).

(d) Section 8.43 recognises that in certain circumstances a prudent discount may be offered to one or more Users, with the shortfall to be recovered from other Users in a manner that the Regulator is satisfied is fair and reasonable.

The tariff design principles set out in the Code form the basic framework for setting transmission tariffs in the Victorian gas market. GasNet has recognised the following tariff objectives, which incorporate both the principles outlined in the Code, as well as other design objectives.

(a) Efficiency, in terms of the promotion of efficiency in:

(i) *customers' usage of pipeline system* - transmission prices should, where possible, signal to system Users the economic costs of use of the system, and promote maximum utilisation of the system;

(ii) *the operation and maintenance of pipeline system* - transmission prices should be consistent with the efficient operation and maintenance of the pipeline system and minimise the costs of the service levels requested by Users; and

(iii) *investment in system augmentation* - transmission prices should signal efficient new investment in the pipeline 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.

(e) Consistency with full retail competition - ensuring that transmission tariffs do not artificially impede customer churn.

In the context of section 8.1(e) of the Code, GasNet submits that a tariff is generally regarded as being efficient (in economic terms) if it lies below the stand-alone rate (ie. the bypass tariff) and above the marginal cost of providing the service.

The marginal cost of providing the service can mean either the short-run cost (assuming only existing assets) or the long-run cost, which includes the cost of reinforcing the pipeline. These issues have been discussed at greater length in the GasNet Tariff Consultation Paper (Annexure 10) and it is beyond the scope of this document to discuss this issue further. In summary, GasNet believes that whilst a tariff should approximate at least the long-run marginal cost of augmentation, it should not be set at a level which inhibits utilisation in the short run (provided the tariff at least recovers the incremental operating costs). Ultimately a long-run marginal pricing signal is always communicated to a User via the actual augmentation cost to expand the capacity of the system, which, under the economic feasibility test implicit in the Code (for example, section 8.16(b)(i) of the Code), is fully allocated to the party which requires the augmentation.

GasNet believes that the existing tariff decision (as modified) reasonably meets these requirements for efficient design. However, in some instances, such as the allocation of overheads, the efficiency principle provides no guidance.

The tariff design principles often conflict and cannot always be satisfied simultaneously. Therefore the chosen tariff design necessarily reflects a compromise amongst these many requirements.

5.5 Tariff Design Principles

The tariff design for the Second Access Arrangement Period is structured along the following principles, which are unchanged from the existing design except where noted. The justification for these design principles was canvassed in detail in (and accepted by the Commission as part of) the original TPA Access Arrangement Information.

(a) The system is divided into withdrawal zones, where a charge is levied on the withdrawing User, and injection points, where the charge is levied on the injector. In respect of the actual charges to be levied on Users, there is no assumed relationship between injections and withdrawals, except in certain zones where matched rebates are offered. This corresponds to the Market Carriage structure, where Users can inject and withdraw as they please, with any differences taken to be purchases (or sales) on the spot market.

(b) The injection point charge recovers the cost of the injection pipeline. The withdrawal charge recovers the cost of transmission from the injection pipeline to the User.

(c) The cost of transmission through the withdrawal zones is based on a forecast of physical flows. Gas is assumed to have followed the physical path even if it was injected at a different injection point.

(d) Costs are allocated to 1 in 2 winter peak flows and annual flows in the ratio of 60% to peak and 40% to annual. This differs from the current model which allocated 65% of costs to the 1 in 20 winter peak flow. (The cost allocation procedure is described in detail in the next section.)

(e) Withdrawals are charged within 15 withdrawal zones (an increase over the current 12 zones to reflect system expansion and the need for prudent discounts).

(f) Within each withdrawal zone there are up to 3 tariff classes. The existing tariff classes of Tariff-D and Tariff-V are supplemented by a storage refill tariff. The reason for introducing this new class is discussed below in section 5.9 below (Charging Parameters).

(g) Injection tariffs are charged at each of the injection points.

(h) The injection charge is levied on the ten peak injection days over the winter at each injection point (as compared to the current charge levied on five peak days).

(i) The withdrawal charge is levied on the actual flows each month (an “Anytime” charge). A different withdrawal charge applies to each tariff class. The reason for changing from the existing design is discussed below in section 5.9 below (Charging Parameters).

(j) There is no “wash-up” procedure on withdrawal charges. However, to provide a smoother payment schedule for Users, injection charges will be forecast for each injector and levied monthly on a sculpted profile. An injection charge wash-up will be performed after September each year when the actual peak days are known.

5.6 Tariff Derivation Procedure

In broad terms, the tariff is calculated using the following procedure.

(a) The peak and annual flows at each off-take are forecast for the Access Arrangement Period. The forecasting procedure is described in detail in section 9.3 of the Submission (Forecast Volumes).

(b) Costs are allocated to each off-take using the procedures described in section 5.7 of this Schedule (Cost Allocation Procedures). The allocation is to each tariff class at each off-take. The tariff classes are defined below in section 5.10 of this Schedule (Tariff Classes).

(c) The costs at each off-take are aggregated into the 15 withdrawal tariff zones and the 3 injection pipelines.

(d) The parameters for charging tariffs on the injection pipelines and within the withdrawal zones are defined in section 5.9 of this Schedule (Charging Parameters).

(e) The tariff is the result of dividing the charging parameters into the allocated costs for each injection pipeline and withdrawal zone. These tariffs are levelised over the period 2003-2007 using the real, pre-tax WACC at the selected X-factors. The selected X-Factors are described in section 5.14 of this Schedule.

5.7 Cost Allocation Procedures

This section describes how costs are allocated to specific off-takes and tariff classes.

Cost are grouped into the following categories, and allocated as shown in the following Table.

Cost Category	Allocation Method
System Assets (return on and of capital) (excluding the SWP and Interconnect Assets)	Physical path
Direct Operating Costs[24]	Physical path
SWP Costs	Direct to zone
Costs rolled-in under the System-Wide Benefits Test (Interconnect Assets)	Postage Stamp
Interconnect Zone Residual Costs	Direct to zone
Non-System Assets[25] (return on and of capital)	Postage Stamp
General & Administrative Operating Costs	Postage Stamp
Return on Working Capital	Postage Stamp
Benefit Sharing Allowance and K-Factor Carry-Over	Postage stamp
Asymmetric risk	Postage stamp
Capital raising costs	Postage stamp

5.7.1 *Physical Path Cost Allocation*

The aim of this cost allocation procedure is to allocate costs to each User in proportion to that User's use of the transmission system assets. Therefore, a User who uses a short section of the system will, in general, pay a lower cost than a User who uses a longer section of the system.

The specific assets that are used by a User are determined by the physical path taken by the gas flow from the relevant injection point to the User's off-take. The relevant injection point for each off-take is determined by a process of allocating the forecast injection volumes from each injection point to the off-takes based on the physical flow dynamics of the system, until the

[24] Direct Operating Costs are the O&M costs less the General & Administrative (or corporate overhead) costs.

[25] Non-System Assets cover land, buildings and office equipment associated with G&A activities.

injection volumes have been exhausted. The majority of the system is assumed to be supplied from Longford, since this is where the greatest volumes are injected. To the extent that the injection volume forecast is changed, the physical paths will also change.

The transmission system has been divided into 27 pipeline segments, determined by the points at which pipeline diameter changes. Certain pipeline segments are associated with compressors and in-line system regulators. The cost that is associated with each asset segment is determined by a procedure that avoids vintage effects, as follows.

(a) The total return on and return of assets is determined for all of the pipeline, regulator and compressor assets.

(b) This cost is allocated amongst the pipeline segments and compressors according to the Optimised Replacement Cost (ORC) of each asset.

(c) The direct pipeline operating costs are allocated to each pipeline segment according to the pipeline length. Compressor and regulator operating costs are allocated to each unit directly.

This procedure effectively disregards the vintage of each asset. It also means that refurbishments of the system, such as the Gooding and Lurgi pipeline refurbishments, are allocated across the entire system rather than to specific zones (however capacity augmentations are allocated to the associated pipeline segment in line with the incremental pricing principle in section 8.16 of the Code). This procedure, which is employed in the existing tariff design, is intended to reflect the principle that the tariff for a segment of pipeline should be related to its service potential, and not to its age.

In contrast to the existing tariff methodology, GasNet will allocate direct operating costs to the injection pipelines[26], including compressor maintenance and fuel costs where relevant.

5.7.2 *Allocations to Peak and Annual Flows*

The physical path allocation procedure described above allocates the cost of each pipeline segment to Users according to the use made of that pipeline segment. Therefore it is necessary to define what is meant by “use” of the pipeline segment.

The aim of allocating costs on the use of the pipeline is to send an appropriate price signal to each User, to enable that User to respond to the correct economic signal, and to ensure that each User is paying its share of the opportunity cost of each asset.

It is common practice to consider the peak flow through a pipeline as the relevant cost driver, on the basis that the pipeline is constructed to carry the peak flow. However, this is not a forward-looking concept as required by economic theory. The appropriate long-run price signal is the cost of augmenting the capacity of the pipeline (in the short run it is mainly the cost of additional compressor fuel required to increase the flow in an existing

[26] Indirect costs are all allocated to withdrawals.

unconstrained pipeline). The augmentation cost is related to the incremental capacity required to carry growth in the peak, but this is generally less than the unit cost of the existing pipeline, given the economies of scale in pipeline construction and augmentation. For example, it is relatively inexpensive to augment an uncompressed pipeline, whilst the cost to augment a fully compressed pipeline could approach the unit cost of the original pipeline.

This discussion is relevant to gas transmission from a single injection point to a single withdrawal point. However, another relevant consideration is the flow dynamics on the pipeline network. The GasNet system is characterised by four gas sources injecting into a central hub, with a number of low volume laterals off the hub. Gas flow within the hub is not at present constrained and there are a number of null points which move around according to the relative injection volumes from day to day. In this part of the system it is not appropriate to consider price signals based on peak flows.

In a practical sense, the GasNet system should be analysed in terms of:

(a) injection pipelines, which could become constrained if volumes grow (and where the peak flow is the indicator of possible constraint);

(b) the hub, which will, for the foreseeable future, be unconstrained; and

(c) low volume laterals off the hub.

The GasNet laterals exhibit a range of capacity utilisation levels, from the very low utilisation on the Murray Valley pipeline, to almost full utilisation of the WTS. This would suggest that it might be appropriate to vary the allocation rule from one lateral to the other. VENCorp has published an estimate of spare capacity on GasNet laterals and it is apparent that there is reasonable spare capacity on each lateral provided gas is sourced from the nearest injection point, with the exception of the WTS. However, the WTS is subject to a bypass risk, and hence a special tariff design is required in this instance (as discussed below).

The existing tariff design allocates 65% of costs to the peak flows, and the remainder to annual flows. Compared to the original forecast for 1998-2002, the forecast flows over 2003-2007 show a significant increase in non-Longford injections, which has the effect of reducing the constraints within the hub. In light of this trend, GasNet has decided to make an incremental change to the peak allocation ratio from 65% to 60%. There are reasonable arguments to reduce this ratio even further given the unconstrained nature of most GasNet pipelines, but this would have the effect of making significant changes in the tariff relativities between high and low load factor customers.

As a result, GasNet has allocated costs on the injection pipeline based on the peak flows and allocated costs on the remainder of the system in the ratio of 55% to annual flows and 45% to peak flows (generating an average peak allocation of 60%).

5.7.3 *Cost Allocation to Off-takes within Pipeline Segments*

Within individual pipeline segments, costs are allocated to off-takes on the basis of the volumes and distances (TJ-km) within the zone for outflows of each off-take and for flows through the zone. This allocation is done for both peak and annual flows in the ratios discussed above.

The costs are then allocated to each tariff class within a zone in the following way.

(a) A rate ($/TJ/km) is derived for both peak and annual supply at each off-take based on the TJ-km for both peak and annual flows within the zone to each off-take and through the zone.

(b) A forecast is made of the Tariff-V and Tariff-D loads at each off-take, and the separate components of peak and annual flows within each tariff class.

(c) The peak and annual rates are applied to the associated components of the Tariff-D and Tariff-V loads at each off-take, to derive the costs to be allocated to these tariff classes at each off-take.

(d) The costs within withdrawal zones are aggregated for each tariff class to the zonal level. The total costs within the injection pipelines are aggregated to generate the total injection pipeline cost.

5.7.4 *SWP*

A separate regime applies to the SWP.

The SWP is a covered pipeline under the PTS Access Arrangement, but is not yet included in the Capital Base. GasNet is including this asset in the Capital Base from 1 January 2003 on the grounds that it passes the tests in sections 8.16 (a) and (b) in the Code. The justification for this procedure is discussed in Schedule 3.

GasNet is proposing an injection tariff to recover the entire cost of this pipeline, as discussed below. The relevant costs that must be recovered from the injection tariff are the asset costs (return on and of capital) and the incremental operating costs associated with the SWP project. This is a direct allocation procedure and the allocation procedure discussed above is not applied to the SWP.

On the basis that this injection tariff recovers these incremental costs, GasNet believes that the SWP passes the test in section 8.16(b)(i) of the Code (often called the economic feasibility test) and can be included in the Capital Base. The calculation of the tariff is discussed below in Schedule 3.7.2.

The SWP project includes the following assets:

(a) the Iona-Lara pipeline;

(b) the Iona-North Paaratte pipeline;

(c) the Iona, Lara and Brooklyn regulators; and

(d) the Iona compressor.

These assets are described in detail in GasNet's Revision Application for the SWP, submitted to the Commission in September 2000.

5.7.5 *Wollert - Wodonga Pipeline*

The Wollert-Wodonga Pipeline supplies the South and North Hume zones, a large part of the Calder zone, the Murray Valley Pipeline, the Echuca zone, Wodonga and potential exports to NSW. This pipeline also enables imports of gas from Culcairn to the northern zones.

GasNet is offering source-based tariffs in the North Hume, Wodonga and Murray Valley zones. That is, there is a relatively high tariff for supply from the south, and a separate discounted tariff for supply from Culcairn, which reflects the significantly shorter transportation distance from Culcairn compared to transportation from the south.

The flows through the northern section of this pipeline (defined as the North Hume zone) are now relatively low. This is because the large load (5 PJ/year) at Wodonga, and parts of the Murray Valley pipeline, are now supplied from Culcairn, which has the effect of substantially reducing the flows on this section. Moreover, the revenue contribution from this section has been substantially reduced given that there are no forecast NSW exports to absorb costs through this pipeline, and given the significant discount now required to be offered at Wodonga. As a consequence, the tariffs for North Hume and Wodonga (Longford supply), and for exports to NSW, will be at least 50% higher than current tariffs based on a rigid application of the cost allocation procedures described above.

GasNet does not believe these tariffs are genuinely cost-reflective. That is, these tariffs will substantially exceed the long-run marginal cost of supply to these zones. The result is an artefact of the rigid application of the cost allocation procedures to a pipeline where gas is flowing in from both ends, with a null point on the pipeline.

GasNet has calculated the tariffs in these zones as follows. Firstly, the tariffs for supply from the south have been calculated from the recovery of the revenue requirement for each asset group assuming complete supply to these zones from the south (that is, ignoring the fact that actual northerly flows are reduced by flows from Culcairn). This tariff methodology is consistent with the methodology used on the rest of the system, assuming that gas actually flows to these zones from the south. These tariffs exceed the long-run marginal cost of supply on the Wollert-Wodonga pipeline, as determined from an economic analysis of an incremental capacity augmentation of the pipeline (an indication of some of the required assets is given in the VENCorp APR, section 5.3.3).

Tariffs from Culcairn are evaluated based on the forecast flows and the same pipeline unit transportation costs as determined by the southerly supply scenario. In the case of Wodonga, a small prudent discount is also required to avoid a bypass opportunity. However, because the actual forecast revenues are a combination of Longford supplied revenues and discounted revenues from Culcairn sourced gas deliveries, the total revenue recovery is insufficient. Hence the path-based tariffs on the rest of the system have been marginally increased by approximately $0.02/GJ to recover the shortfall.

GasNet believes that this procedure is cost-reflective and appropriate. The tariffs will fall between the long-run marginal cost and the stand-alone rates and hence are efficient. Higher tariffs will send an inappropriate price signal to the extent they exceed the marginal cost, and discourage otherwise viable gas consumption. Furthermore, the negative effects of higher tariffs in the Northern zones will discourage flows to a greater extent than a marginally higher tariff in the Metro zone. This is because the delivered gas costs in the Northern zones are approaching the cost of alternative fuels, and hence an increase in tariffs could lead to a significant reduction in growth. On the other hand, the gas tariffs in Metro are relatively low relative to alternatives, and an increase of $0.02/GJ is not likely to have any impact.

5.7.6 *Culcairn Withdrawal Tariff*

While GasNet is not forecasting exports from Culcairn to NSW, it is necessary to publish a tariff in the event that a flow reversal occurs through the Interconnect Pipeline. A properly cost-reflective tariff must recognise the increased flows on the Wollert-Wodonga pipeline that would result if gas were to be exported to NSW. GasNet has calculated a notional tariff based on an increase in northerly flows of 3 PJ per annum, and has applied this to an export volume with an 80% load factor.

5.7.7 *Indirect Cost Allocation (Postage Stamp)*

The indirect costs are the costs associated with the Non-System Assets (return on and of capital), the return on Working Capital, and the General & Administrative operating costs. In line with the existing tariff model, these costs will be allocated to all withdrawals on a per GJ basis. GasNet does not believe the Code specifies which procedure should be used for the allocation of indirect costs. However, the postage stamp method has the benefit that it is non-discriminatory, has been accepted in the existing model, and is widely used.

Where a prudent discount is required, GasNet has only allocated indirect costs to the extent that the tariff is competitive with the bypass option.

5.7.8 *Interconnect and Springhurst Compressor*

The Interconnect Assets were approved by the Commission in April 2000 to be rolled-in to the GasNet Capital Base under the test in section 8.16(b)(ii) of the Code (often called the system-wide benefits test). The relevant assets are:

(a) the bulk of the Interconnect Pipeline (92%);

(b) the Springhurst Compressor; and

(c) the regulators at Wandong, Barnawartha, Wollert and Ballan.

The remaining 8% of the cost of the Interconnect Pipeline is treated as a direct asset recovery for the Culcairn injection tariff.

The Commission's approval permitted GasNet to charge for these assets under a postage-stamp tariff on all withdrawals from the system, with the exception of the WTS.

GasNet proposes to continue with this allocation procedure. However, where a prudent discount is offered, the allocation will be reduced as required.

5.7.9 *Benefit Sharing Allowance and K-Factor Carry-Over*

The Benefit Sharing Allowance and K-Factor carry-over are costs which are associated with activities during the First Access Arrangement Period, but which can be carried forward into the Second Access Arrangement Period.

The K-Factor Carry-Over is associated with limitations on the ability to increase tariffs each year in order to recover the K-Factor allowance.

The Benefit Sharing Allowance is a recognition of savings in operating costs made during the First Access Arrangement Period which are shared in the next period.

There is no obvious (or Code-mandated) allocation rule for these costs. GasNet will simply allocate these costs to withdrawals on a postage stamp basis except those subject to a prudent discount.

5.7.10 *Across system flows*

GasNet has adopted a policy of no backhaul charges for flows against the predominant (forecast) flows on injection pipelines. However, as current tariffs stand, a flow from Longford to Iona would only attract the Longford injection charge plus the local withdrawal charge on the Southwest Pipeline. Similarly, a flow from Iona to Longford would only attract the Port Campbell injection charge plus the local withdrawal charges off the Longford pipeline. GasNet is proposing to levy an additional charge for carriage through the Metro zone, for withdrawals off the injection pipeline which are linked to injections at an unrelated injection point. This charge will be the Metro zone tariff discounted for the indirect cost allocations (which are already recovered from the withdrawal zones).

5.8 Charging Parameters – Withdrawal Zones

The charging parameters for withdrawals under the current tariff are:

Tariff	Charging Parameter
Withdrawals Zones	
Tariff-D	The five peak day flows from the zone for each market participant.
Tariff-V	The winter volume flows from the zone for each market participant.
Murray Valley	The five peak day flows from the zone for each market participant
Withdrawal Points (Barnawartha, Carisbrook, Chiltern Valley)	The five peak flows through the withdrawal point for each market participant.

These parameters (and in particular the five day peak flow methodology) were designed in 1998 to address perceived peak constraints on the main Longford pipeline. However, as discussed in the Submission, there have been a number of important developments since 1998 which have reduced the risk of peak constraints. For example, the addition of the SWP and the

Interconnect Assets have added new injection points which relieve some of the constraints on the main Longford pipeline. In addition, the warming trend discussed in section 9.3 of the Submission has resulted in lower than expected peak flows. In these circumstances, GasNet submits that, while there remains a strong imperative to provide appropriate pricing signals in relation to peak usage, there is some scope to relax the way in which peak usage is determined.

In addition, GasNet is aware of concerns in the market with the use of peak day flow charges for the withdrawal tariffs. These concerns relate to:

(a) *The ability of Users to realistically respond to the peak signal*. The 5-day pricing signal is ineffective since the 5 chargeable days can only be known in hindsight, making it difficult for Users to respond to the peak signal and plan their production around these peaks.

(b) *The unpredictability of transmission charge liabilities*. Neither the retailer nor his customers can budget accurately for transmission charges when they are not known until well after the event.

(c) *Sending peak price signals when there may be no congestion*. Users are charged on their peak usage even when there was no congestion on the pipeline, or where the User has no AMDQ under the MSO Rules (and therefore is in a similar position to an "interruptible" customer). This is a disincentive to both interruptible flows and winter flows on unconstrained pipelines. The peak charging method is equivalent to an extremely high over-run charge on a Contract Carriage pipeline.

(d) *Duplication of tariff and market price signals*. There is potential duplication between peak signals sent by the tariff, and congestion signals (in the form of uplift and curtailment risks) sent by the gas market. This may place an excessive cost burden on peak flows.

These concerns arise in part because the tariff is based on actual flows rather than reserved capacity, as is the case on contract carriage pipelines. On contract carriage pipelines the peak charge is readily applied and the User's commitment can be planned in advance. A prospective User also receives the appropriate price signal in deciding what capacity to reserve.

GasNet must balance the concerns of the market for simplicity, compatibility with full retail contestability and tariff certainty with the concerns for a cost-reflective tariff.

On balance, GasNet has decided to charge a flat "Anytime" rate for all withdrawals, to be levied monthly on actual flows, with a specific rate determined for each tariff class, as discussed in section 5.10 of this Schedule (Tariff Classes).

The decision to charge a flat rate on withdrawals will be reviewed at the next Access Arrangement Revision. In the interim, GasNet will monitor the market for:

(a) the compatibility of this tariff methodology with full retail contestability;

(b) the need or otherwise for price signals to influence consumption behaviour on the withdrawal pipelines; and

(c) the evolution of the Victorian market, particularly the influence of congestion and surprise uplift as an alternative means to provide peak utilisation signals.

5.9 Charging Parameters – Injection Pipelines

5.9.1 *Background*

The tariff design is built upon the concept that gas is supplied from injection pipelines into a hub, from where it is distributed to Users within withdrawal zones. The injection charges are not linked to the withdrawal charges (except where a matched rebate is offered). The underlying conceptual model is that the injectors are selling gas into a pool and withdrawers are buying gas from that pool. The transmission tariffs are calculated on the assumption that gas will flow along the forecast physical paths.

The current charging parameters for use of the injection pipelines under the current tariff are:

Tariff	Charging Parameter
Longford Injection Point	Five day peak injections over winter. Matched rebate at Latrobe and Lurgi zones.
Culcairn Injection Point	Five day peak injections over the year, and Five peak withdrawals from Culcairn over winter.

The SWP is currently being charged on a similar basis to the Longford pipeline. There is a matched rebate for flows from Iona to the Western System.

The injection charges are calculated to recover the cost of the injection pipeline from the peak flows carried through the pipeline. To the extent that injections are not carried the whole length of the pipeline, a matched rebate is offered.

Under the current design, the Longford charge applies only to flows in the "predominant" flow direction, as forecast at the commencement of the First Access Arrangement Period. A similar methodology is applied to the SWP. In contrast, the charges on the Interconnect Pipeline are applied to flows in both directions, in line with the original forecast.

GasNet has not noted any major concerns in the market with the injection charging methodology currently in place. GasNet intends to maintain the same design for the injection pipelines, based on:

(a) peak flow charges,

(b) charges initially set based on forecast flows; and

(c) matched rebates where the injection pipeline is only partially utilised.

However, GasNet has given some consideration to the appropriateness of charging on the five peak day flows on each pipeline. The number of days which are tariffed is a compromise between retaining a reasonable reflection of the peak utilisation of the pipeline and providing some stability in gas charges. For example, gas flows tend to fluctuate in a random manner from day to day. Hence a charge levied on only a single peak day flow would subject Users to considerable uncertainty, and would unnecessarily penalise occasional random variations. GasNet understands that the Victorian electricity transmission system charges by reference to demand on ten peak days.

GasNet has evaluated this issue and has come to the view that the current five day peak charge on gas injections should be replaced with a ten day peak charge. As discussed above, there is scope to relax the way in which peak usage is measured. In addition, this will lead to a lower level of sensitivity to random variations, and greater certainty for GasNet and for Users.

The injection charges for each injection pipeline for the next Access Arrangement period are described below.

5.9.2 *Longford Injection Charging Parameter*

The Longford injection charge will be levied on the ten peak day injections into the pipeline over the winter period (June-September, inclusive).

Withdrawals made in the Latrobe, Tyers or Lurgi zones which are matched to Longford injections will receive a matched rebate based on the shorter transmission distance on the injection pipeline.

5.9.3 *Port Campbell Injection Charging Parameter*

The Port Campbell injection charge will be levied on the ten peak day flows through the Iona-Lara pipeline over the winter period (June-September, inclusive). These flows will be calculated from the total injections made within the Port Campbell surrounds, less the withdrawals from the WTS or other off-takes at or in the vicinity of Port Campbell.

The charge will not be levied on injections in the Port Campbell Zone which are matched to withdrawals taken from the Western Zone or from the vicinity of Iona.

A rebate will be given on the injection charge for withdrawals from the South West withdrawal zone where the withdrawal can be matched to an injection at Port Campbell.

5.9.4 *Culcairn Injection Charging Parameter*

The Culcairn injection charge will be levied on the ten peak day injections into the pipeline over the winter period (June-September, inclusive). There will be no charge for transportation from Barnawartha to Culcairn.

GasNet is not forecasting any material exports to NSW, hence there is no backhaul tariff from Barnawartha to Culcairn. This decision is consistent with the principle adopted on the other injection pipelines. Where gas is notionally backhauled against the predominant flow, there is no charge.

The principle of a zero backhaul charge is straightforward on the Longford and Southwest pipelines, since the predominant flows into the hub through these pipelines is very large. A notional backhaul charge of zero is consistent with a deemed gas swap at either end of the pipeline which would result in the same outcome. However the Interconnect Pipeline carries a lower volume, and there is a possibility that the physical flow might reverse during the Second Access Arrangement Period, although this is not expected to happen. In these circumstances, a zero backhaul charge on the Interconnect Pipeline would not be cost-reflective. However, a flow reversal of this magnitude would also change the cost allocation to customers along the whole length of the Wollert to Wodonga pipeline. Therefore if GasNet adjusted the Interconnect tariff for a flow reversal, there would be equally compelling reasons to adjust all the tariffs on the GasNet system. This would undermine the incentive-based regulatory model under which GasNet operates, whereby tariffs are "locked-in" for the Access Arrangement period, giving tariff certainty to customers.

GasNet considers that a flow reversal on the Interconnect Pipeline would not be sufficient to warrant a tariff adjustment. According to the VENCorp APR (section 5.3.3), the Culcairn export capacity is limited to about 3 PJ/year, but in a 1 in 20 winter, this capacity is significantly less (unless existing load on the Wollert to Wodonga pipeline is curtailed). If an export flow was required, the Wollert-Wodonga pipeline would require augmentation as described in the VENCorp APR. This cost would be sheeted home to the User under the incremental pricing principle contained in the Code. Therefore the User would receive the correct price signal through the augmentation cost.

Off-takes on the Interconnect Pipeline will receive a rebate on the injection charge.

In addition, a matched rebate will be offered on the withdrawal zone tariffs for withdrawals in the Wodonga, North Hume, and Murray Valley zones, where these withdrawals are matched to injections at Culcairn. This rebate reflects the lower cost of transportation to these zones from Barnawartha.

5.10 Tariff Classes

GasNet will charge a differential withdrawal tariff in relation to Tariff-V and Tariff-D customers to reflect the significantly different load factors for these customer classes. This will ensure there is minimal rate shock for each customer class from the existing tariffs.

However, because GasNet is charging a flat rate for withdrawals from the system, there is a prospect that certain customer types may be disadvantaged. GasNet believes that a new class should be introduced to avoid a potential bias.

5.10.1 *Storage refill*

Gas is generally withdrawn from storage at high rates during the peak periods when alternative supplies are inadequate, and refilled at a slow rate during off-peak or non-congested periods. There is an argument that storage is simply an interim holding point between the supply point and the final customer, rather than a delivery location in its own right. Storage refill is, by its very nature, unlikely to impose congestion on a pipeline. Furthermore storage provides a benefit since it provides a competitive source of peak gas supply and additional security for the system.

At present, storage refill pays the Tariff-D withdrawal rate, but attracts no peak withdrawal charges because storage is unlikely to refill on peak days. Therefore a move to a flat rate withdrawal tariff would disadvantage refill compared to present arrangements. GasNet believes that fixed costs should not be allocated to storage refill to the extent that this will inhibit the use of storage. Therefore, GasNet will charge the marginal cost of refill, which is principally the cost of additional compressor fuel required to deliver gas to the storage.

The LNG storage is normally refilled as soon as possible in order to maintain system security levels. Hence it is likely to be refilled during the winter and spring periods, although it will not be refilled on peak days. Hence the marginal cost is the incremental cost of compressor fuel at the Gooding compressor station.

The WUGS storage is normally refilled over the summer period. To the extent that the WUGS storage is refilled with gas from Longford via Melbourne, the incremental cost comprises compressor fuel at the Brooklyn compressor station. This would generally require the operation of both Centaur units at Brooklyn. The intensity of operation of the Brooklyn station is influenced by the level of demand in Melbourne, which would favour refill over the summer months. However, the fuel consumption at Brooklyn is also influenced by the demand for gas at power stations at Newport and Geelong, which could be quite high during the summer period.

5.11 Incremental Pricing of the SWP

5.11.1 *Proposal*

As discussed in section 5.7 above (Cost Allocation Procedures), the SWP will be allocated the full direct costs of the SWP assets (return on and of capital) and the incremental operating costs.

The SWP is expected to carry significant volumes from Iona to Melbourne (as discussed in section 9.3 of the Submission). GasNet will tariff the SWP as an injection pipeline and apply an injection charge in a similar manner to the injection charge applied to the Longford pipeline (based on the ten peak day flows at the injection point).

Currently, the injections into the SWP are made at the WUGS facility at Iona, which has sufficient installed compressor power to inject gas at the maximum allowable operating pressure of the Iona-Lara pipeline of 10 MPa. However, in future it is anticipated that there will be a number of other connection points established in the vicinity of Port Campbell which will enable injection into the SWP. These connection points will access gas from the new fields being developed at Port Campbell (Santos), Minerva (BHPP), and Thylacine - Geographe (Origin/ Woodside).

Therefore GasNet will levy the injection tariff on any injections made in the vicinity of Port Campbell, where the gas is directed along the SWP towards Lara.

Where the gas is directed to the WTS, (that is, where the injections are matched to withdrawals in the Western system) or off-takes adjacent to Port Campbell, no injection charge will be levied.

5.11.2 *Revenue Requirement*

The standard procedure to calculate the revenue requirement for a pipeline is to apply a depreciation profile based on real, straight line depreciation over the economic life of the asset, and to recover this depreciation allowance in each year of the Access Arrangement period. This constitutes the return of capital. The return on capital is the WACC applied to the asset value as written down by the depreciation allowance. This procedure generates a real decline in the revenue requirement profile

However, GasNet is conscious of the fact that the SWP is a new pipeline in competition with other gas injection pipelines, and that a reasonable tariff is required in order to encourage growth on the pipeline.

Therefore GasNet has taken three initiatives to generate the lowest possible tariff on the pipeline.

(a) The economic life of the SWP is set to end in 2052. This is over 20 years longer than the economic life of the rest of the GasNet pipelines, which will impose a greater level of risk on GasNet.

(b) The revenue requirement relating to the SWP is levelised over the first 20 years at a flat real rate. This has the effect of deferring revenue recovery to the future, on the assumption that the volumes will grow faster as a result of the lower tariff. Based on this levelisation procedure, the depreciation allowance in the early period of the life of this asset is negative. This means that GasNet is effectively adding capital to the pipeline over time in order to encourage future utilisation.

(c) GasNet will set an X-factor for the injection charge of zero, which has the effect of reducing the charge in the early years of the Second Access Arrangement Period.

5.11.3 *Port Campbell Injection Tariff*

The injection tariff is derived by applying a CPI-X tariff path to the charging parameter for the Port Campbell injection zone. The initial tariff is set so that the NPV of the tariff revenues equates to the NPV of the levelised revenue requirement for the SWP.

Revenues from the WUGS storage refill are not included, as these are designed to match the marginal supply costs from operation of the Brooklyn compressor station.

An allowance is made for revenues from Colac on the Iona-Lara pipeline, which will receive a matched rebate owing to its location on the pipeline.

As described above in section 5.9 (Changing Parameters), a matched rebate will be offered for injections which do not flow along the Iona-Lara pipeline.

The X-Factor for the SWP will be set at zero in order to encourage early utilization.

5.12 Incremental Pricing of the Interconnect Pipeline

5.12.1 *Revenue requirement*

The Interconnect Pipeline carries gas from the Culcairn injection point to Barnawartha, where it joins the North Hume and Wodonga zones.

The Interconnect Pipeline has been allocated 8% of the direct cost of the Interconnect Assets. The remaining 92% and the operating costs are recovered under a postage stamp tariff as approved by the Commission in 2000.

The revenue requirement for the Interconnect Pipeline is calculated using a real, straight-line depreciation profile, as for all other assets in the GasNet system with the exception of the SWP.

5.12.2 *Culcairn Injection Zone*

The allocated costs of the Interconnect Pipeline are recovered entirely from the Culcairn Injection Tariff. The injection tariff path is derived by applying a CPI-X tariff to the charging parameter for the Culcairn Injection Point. The initial tariff is set so that the NPV of the tariff revenues equates to the NPV of the Interconnect revenue requirement.

5.12.3 *Matched Rebates*

Off-takes on the Interconnect Pipeline are given a rebate on the injection charge if the injections are matched to the withdrawals.

5.13 Tariff Zones

5.13.1 *Retain existing zones*

Withdrawal tariff zones are defined in order to simplify the implementation and administration of the transmission tariff. GasNet is not aware of any concerns in the market about the current extent and coverage of the existing tariff zones, with the exception of certain bypass opportunities in the vicinity of injection points.

In the interests of consistency and stability across Access Arrangement periods, GasNet proposes to maintain the current tariff zones. However, GasNet has divided some zones for the purpose of offering a more cost-reflective tariff, where bypass opportunities have been identified. These new zones are described below.

5.13.2 *Tyers zone*

The current Latrobe zone includes the large 500 mm lateral from Tyers to Morwell. This asset is effectively charged to all other off-takes within the zone, most of which are directly connected to the Longford injection pipeline. This creates a bias which increases the bypass risk within the Latrobe zone. Therefore, the Tyers to Morwell pipeline will be separated as a new zone. The main Users on this lateral are the Morwell township and the Jeeralang and Loy Yang power stations.

5.13.3 *Wodonga zone*

Wodonga is at the extreme northern end of the long North Hume zone and is the largest load in the region. A high pressure distribution pipeline runs from the GasNet off-take through the city and north to the ANM plant. The location of this pipeline means that a bypass pipeline could be constructed from Culcairn directly to the plant and into the Wodonga distribution network. Therefore GasNet has separated the short pipeline from Barnawartha to Wodonga as a new zone. A prudent discount will be offered for injections made at Culcairn, as discussed below.

5.13.4 *Dandenong notional point*

There is a prospect of a new injection point at Pakenham, which would take gas transported from a new field development at Yolla, via a gas processing plant at Lang Lang.

GasNet is not forecasting this project to proceed. However, if it does go ahead, the proponents would have the opportunity to bypass the main GasNet pipeline between Pakenham and Dandenong, and connect directly to the large distribution off-takes at Dandenong (thereby avoiding both the GasNet system and the VENCorp spot market).

GasNet can offer a prudent discount by defining a new zone at Dandenong where the bypass tariff will apply. This is a notional zone because it will only be identified if the Pakenham injection point is actually connected, and the discounted withdrawal tariff will only apply to matched injections at Pakenham. The Pakenham injectors will also attract a discount on the Longford injection tariff commensurate with the distance between Pakenham and Dandenong.

5.13.5 *West Gippsland zone*

Currently there are no off-takes on the main pipeline between the Latrobe and Metro zones. However, in the event that a connection is made in the future, a published tariff will be defined for this zone

5.13.6 *Warrnambool and Koroit*

The WTS will be covered by this Access Arrangement from 2003 and will be designated the "Western zone". The WTS serves five towns along the length of the pipeline, and carries a volume approaching 4 PJ/year.

An interstate pipeline is expected to be built between Iona (or nearby location) and Adelaide by 2004. This pipeline is likely to be installed within the same easement as the WTS for part of its length, and will pass two towns currently served by the WTS.[27]

There is a bypass opportunity at these towns, and GasNet will offer a prudent discount from 2004 as described below. GasNet will not define a new zone, but the two at-risk towns will receive a special published tariff.

5.13.7 *Zone Definition*

A withdrawal zone is defined by the transmission pipelines and the associated connection points that constitute the zone. The gas that flows from the off-takes on those pipelines is charged the published zonal tariff. If a new withdrawal connection is made on one of these zonal pipelines, then that off-take will also be charged the zonal tariff.

The connection points that constitute each zone are described in Schedule 2 of the GasNet Access Arrangement.

The current withdrawal zones are built around a large central hub (the Metro zone) which contains approximately 85% of the total load. The remaining zones are laterals and injection pipelines. GasNet has considered the advantages and disadvantages of breaking up the Metro zone.

Advantages	A more cost-reflective tariff.
Disadvantages	Complexity for Retailers.
	A barrier to customer churn under full retail contestability.
	An increased risk of bypass pipelines across zone boundaries.

GasNet considers that, in the case of the Metro zone, the advantage of cost-reflectivity is outweighed by the commercial and technical difficulties of any break-up. The reality is that the Metro zone is only one component of a more complex distribution network within Melbourne. In some cases the segregation between transmission pipelines and distribution pipelines is blurred. Hence it is inappropriate to tariff the transmission pipelines on a distance-based tariff whilst the distribution network is tariffed on a postage-stamp basis.

For example, the Inner Ring Main was transferred to a Distributor when the transmission and distribution networks were disaggregated, whereas GasNet was allocated the Outer Ring Main. The Inner Ring Main supplies gas from the GasNet system at Dandenong to a large part of eastern Melbourne. However, an adjacent region in the east is supplied from the north via the Outer Ring Main (93km) and the Keon Park lateral (all GasNet assets). In these circumstances it is not cost-reflective to track gas flows through GasNet pipelines, but accept a postage-stamp distribution tariff. The preferred solution is to acknowledge that supply to the metropolitan area has evolved to service the needs of all metropolitan customers, and that a postage-stamp tariff is appropriate throughout the region.

[27] The new pipeline will use the same easement as the Western system whether it is the Southern Gas Pipeline or the alternative SEAGas proposal.

Furthermore, it should be recognised that a cost-reflective Metro zone tariff will be based on a forecast of gas flows through the region. These flows consist of gas supplies from multiple injection points, and it is reasonable to expect that the actual flows will differ from the forecast in ways that could see flow reversals within the region against the original forecast. Therefore, it is somewhat illusory to believe that tariffs can be made cost-reflective, on what is essentially a distribution network.

5.14 The X-Factor and the Initial Tariffs for 2003

GasNet tariffs will be designed to follow a CPI-X price path. This means that the tariffs will be escalated annually by the actual CPI inflator, less a prescribed X-Factor (GasNet uses a lagged CPI when tariffs are escalated to remove the requirement to forecast the CPI inflation rate each year).

Each year the tariffs will be escalated by the factor (1 + CPI) * (1 – X)

The X-Factor is derived as follows.

(a) An initial estimate of the X-Factor is postulated.

(b) Starting values for 2003 injection and withdrawal tariffs are postulated for each zone.

(c) The tariffs are escalated at (1+CPI)*(1-X) for five years, and applied to the forecast volumes to generate the anticipated revenue from each zone.

(d) The starting tariff values are adjusted so that the NPV of the costs allocated to each zone over the five year period is equal to the NPV of the anticipated revenues within each zone.

(e) The X-Factor is consistent across all tariff components, but a zero value is sued in some zones where special outcomes are sought.

(f) If the starting tariffs are considered to have shifted too far from 2002 levels, then a revised X-Factor is chosen, and the process is repeated. Consideration is also given to the longer-term trends in tariffs, with a view to avoiding tariff shocks at the next tariff revision.

GasNet has decided to use a zero X-Factor for the Murray Valley zone in order to encourage connections to natural gas. Similarly, GasNet has selected a zero X-Factor for the Port Campbell injection tariff, to encourage an early build-up of flows on the SWP. A zero X-Factor is also applied at Wodonga and the Western Zone towns of Warrnambool and Koroit, where a prudent discount has been applied.

With these exceptions, GasNet has calculated an X-Factor of 5% for all remaining tariffs. This factor provides a reasonably smooth price path between the First Access Arrangement Period and the Third Access Arrangement Period.

5.15 Brooklyn Loop

5.15.1 *GasNet proposal*

The Brooklyn Loop is an augmentation of the SWP which is designed to increase the deliverability of the SWP into Melbourne. It consists of a 500 mm pipeline with a length of 36 km which is laid in the easement adjoining the existing Brooklyn-Corio pipeline (the Loop terminates at Paradise Road approximately 11 km from the Lara connection point with the SWP). The project is described in detail in section 7.3.3 of the Submission.

Based on the supply and demand forecast presented by GasNet in section 9.3 of the Submission, GasNet expects to augment the SWP capacity by winter 2007. The Brooklyn Loop is the first step in the augmentation of the SWP, and adds 70 TJ/day of capacity (VENCorp APR November 2001, page 46). The subsequent steps would be to complete the Loop from Paradise Road to Lara, and then to install the Stonehaven compressor. As discussed in the VENCorp APR, the full Loop adds significant capacity, and may be the most sensible option. However, the supply/demand balance shows that the system does not require this additional capacity after 2007. Therefore, to construct such additional capacity would be a speculative investment as seen from this point in time.

Section 8.20 of the Code allows forecast capital expenditure to be included as New Facilities Investment in the calculation of the Reference Tariff provided it is reasonably expected to pass the tests in section 8.16 of the Code. GasNet believes it is likely the Brooklyn Loop will pass these tests.

The reasons that the Brooklyn Loop passes section 8.16 (a) are discussed in section 7.3.3 of the Submission. However, GasNet will only seek to include in the forecast Capital Base the Recoverable Portion, which is the amount that satisfies the test in section 8.16 (b)(i) of the Code. The remainder of the investment will be treated as Speculative Investment. As indicated in the VENCorp APR, the full Loop may be the more sensible investment. GasNet may subsequently choose the greater investment, and place a greater amount in the Speculative Fund, on the expectation that the demand after 2007 will justify the investment.

5.15.2 *Recoverable Portion*

GasNet has calculated the (un-augmented) SWP injection tariff on the principles described above in Schedule 3.7 and based on a capacity limit of 250 TJ/day. This represents the prevailing tariff which is required to calculate the anticipated incremental revenue generated by the Loop. This tariff has then been applied to the additional capacity of the Brooklyn Loop, which is up to an additional 70 TJ/day. The NPV of the incremental revenues earned from the Loop is $20.7 million in 2007. This value is treated as New Facilities Investment for the purposes of calculating the new GasNet tariffs.

5.16 Prudent Discounts

5.16.1 *Background*

Section 8.43 of the Code specifies the conditions under which a prudent discount may be offered at the commencement of a new Access Arrangement Period.

Section 8.43 contemplates a situation where a User can obtain a lower cost service from a bypass pipeline than from the Reference Tariff on the regulated pipeline system. In these circumstances it may be appropriate to offer a discount to the User in order to retain their (albeit reduced) contribution to revenue on the regulated pipeline. A discount is deemed to be prudent if, in the situation where the at-risk User is retained at a discounted tariff, the Reference Tariff calculated for all other Users is lower than the Reference Tariff calculated without the at-risk User's contribution. In other words, a discount is prudent if other Users are better off with the at-risk User on the system rather than off the system, even though the at-risk User pays a discounted tariff.

This test is necessarily open to some conjecture as it requires speculation as to how Reference Tariffs would be calculated under various circumstances. Reference Tariffs are considered to be efficient if the Reference Tariff is above the marginal cost of supply and below the cost of a bypass pipeline. This means that if a customer is to be retained on a pipeline, they must pay at least the marginal cost of supply. However the fixed costs (eg overheads) which are not recovered from the customer must be allocated to other Users on the system. Provided the allocation of fixed costs to other Users does not cause any tariff to exceed the stand-alone rate, the Reference Tariff is efficient.

In summary, GasNet interprets the principle underlying the prudent discount test to be that a User should pay at least the marginal cost of supply. Any contribution made by a User above the marginal cost of supply will be a net benefit to other Users on the system (by defraying overheads, for example).

This leads to a further question as to whether the relevant cost is the short-run marginal cost (which ignores asset costs) or the long-run marginal cost (which includes the cost of augmenting the assets). If the short-run marginal cost is used, then the prudent discount need only make a contribution to the incremental operating costs. If the long-run marginal cost is used, then the prudent discount must make a contribution to the asset costs as well as the incremental operating costs. The short-run marginal cost test is the least stringent, since it implies that if a customer is lost from the system, then all fixed costs, including asset costs, will be re-allocated to other Users. In many circumstances, this will be the acceptable procedure.

However, in the first instance, when assessing a prudent discount, GasNet will apply the more stringent test that the prudent discount must exceed the long-run marginal cost. As an approximation to this cost, GasNet will use the cost allocation of assets under the physical path model discussed above, plus an estimate of the incremental operating costs.

An important consideration in discussing prudent discounts is the additional charge levied by VENCorp on all withdrawals. A bypass pipeline from a new injection point will avoid the VENCorp gas market, and hence the VENCorp fees and charges. In addition, the customer will not pay uplift charges and linepack account costs. Furthermore, the supply could be firm, and would not be subject to the risk of curtailment under the MSO Rules if an emergency or constraint arose on the GasNet system. For these reasons a User might perceive a lower risk and more certain costs by constructing a bypass pipeline. This would increase the attractiveness of the bypass beyond the "vanilla" transmission costs and VENCorp charges.

5.16.2 *Latrobe Zone Discount*

The Latrobe withdrawal zone is a 65 km pipeline from Longford to the end of the duplicated section of the Longford injection pipeline, just short of the Gooding compressor station. The zone contains the towns of Sale, Rosedale, Traralgon, and the large Paperlinx paper plant at Maryvale. There is also a private pipeline lateral to the Edison Mission peaker plant. The only physical GasNet asset within the withdrawal zone is the short lateral to Maryvale.

The customers at these off-takes must pay the Longford injection charge (discounted to reflect the lower transportation distance) plus a withdrawal charge that recovers the cost of the zonal assets and a contribution to overheads.

It is relatively straight-forward to construct a bypass pipeline from Longford to Maryvale, servicing the towns en route. GasNet has designed and costed such a bypass pipeline, and calculated an estimate of the bypass tariff. Since VENCorp is not proposing to discount its tariff, GasNet has derived the prudent discount by deducting an amount equal to the forecast VENCorp fees and charges.

Based on this analysis, the proposed GasNet discounted tariff (including both injection and withdrawal charges) is:

Tariff-D $0.06/GJ in 2003

Tariff-V $0.07/GJ in 2003

These tariffs escalate at CPI-5% because the bypass risk increases as the load grows over time (reflecting the economies of scale in pipeline construction).

Analysis shows that these tariffs exceed the combination of the injection charge and the withdrawal charge, if overhead allocations are excluded. Therefore GasNet believes the discount is prudent.

The discounted tariff will be implemented as a matched rebate contingent on injections at Longford. The matched injection rebate will be retained, and the Latrobe withdrawal zone tariff will be adjusted down to give a combined injection and withdrawal tariff equal to the prudent discount.

5.16.3 *Wodonga Prudent Discount*

Albury/Wodonga is currently supplied from the GasNet system at Wodonga. The city gate is approximately 10 km from the point where the Interconnect Pipeline joins the main Wollert-Wodonga pipeline.

The Wodonga gas volume is approximately 5.0 PJ/year and growing. The largest industrial consumer is the ANM paper plant (now owned by Norske-Skög), which is located to the north of the city of Albury/Wodonga. It is supplied by the Origin Energy distribution pipeline which runs from the Wodonga city gate, under the Murray River, and through the city proper, before terminating at the ANM plant.

It is possible to connect directly to the ANM plant and the Origin distribution system by constructing a 41 km. bypass pipeline from Culcairn. This poses an immediate bypass threat.

GasNet has evaluated the cost of a bypass pipeline and derived the bypass tariff. VENCorp is not offering a discount on the VENCorp fees, so an amount equal to the VENCorp tariff has been deducted to give the following discount tariffs:

Tariff-D $0.14/GJ in 2003

Tariff-V $0.22/GJ in 2003

The marginal cost tariff is the sum of the Culcairn injection tariff, and the Wodonga withdrawal tariff, excluding allocated overheads. This tariff is significantly less than the required discount tariff, therefore the discount can be considered as prudent.

The tariff will be implemented by adjusting down the matched withdrawal rebate for the Wodonga zone (by allocating a lower share of overheads than other zones receive). The Culcairn injection tariff will be retained, and the withdrawal tariff will be set so that the combined tariff equals the prudent discount.

5.16.4 *Western Zone Discount*

The new Western zone covers five towns in the Port Campbell to Portland area with consumption of approximately (forecast 2003) 4 PJ of gas. The system consists of 216 km of pipelines, and is valued at about $9m. The current tariff is approximately $0.50/GJ.

However there is a bypass threat posed by the proposed Iona to Adelaide pipeline. There are currently two proposals, both expecting first flows in January 2004. The Duke Southern Gas Pipeline follows the pipeline easement to within 20 km. of Portland, and then diverges towards Adelaide. It passes the city gates for Warrnambool and Koroit. The SEAGas pipeline follows the Western System easement past Warrnambool, and diverges towards Adelaide in the vicinity of Koroit.

The economies of scale of the South Australian pipeline are such that the owners can offer a significant discount over the current tariffs for the Western zone. However, there will be costs to install connections and regulators operating at 15MPa, which is the anticipated MAOP of the South Australian pipeline.

The volumes at Warrnambool and Koroit constitute 55% of the total volumes on the Western System. Therefore there is a significant bypass threat.

GasNet proposes to offer a prudent discount in the Western zone. This will minimise the risk that the Western zone customers will shift to the competing pipeline.

The most stringent test of a prudent discount is to set the prudent discount at the long-run marginal cost. The relevant long-run costs on the Western System are:

(a) the capital costs associated with the Western System pipelines;

(b) the marginal GasNet operating costs; and

(c) the marginal VENCorp operating costs.

A bypass tariff can be calculated for each town under threat in the Western zone. Based on these tariffs, one can calculate the maximum revenues that would be earned from the Western zone at the discounted tariffs. These can be compared to the marginal costs of continued supply to the existing loads. If the discounted revenues exceed the marginal costs then a prudent discount can be offered.

GasNet considers that the towns of Portland, Cobden and Hamilton are not at risk of bypass under current load forecasts. However, the towns of Warrnambool and Koroit could access a better tariff from the Iona to Adelaide pipeline than that offered on the GasNet system (under the standard cost allocation procedures on the GasNet system).

Analysis shows that an adequate discount can be offered by simply reallocating overheads away from the Western zone. Therefore GasNet considers that the proposed discounts are prudent, and proposes to offer a discount to the towns of Warrnambool and Koroit. In order to minimise the cost burden on other Users, GasNet will only offer the discount from 2004.[28]

The proposed prudent discount tariffs (in $2003) are:

Warrnambool

Tariff-D $0.06/GJ

Tariff-V $0.07/GJ

Koroit

Tariff-D $0.19/GJ

Tariff-V $0.27/GJ

These tariffs are escalated at CPI each year.

[28] The prudent discount is offered on the Latrobe and Wodonga zones from 2003 because the analysis shows that this is the efficient tariff. However the Western System bypass is not a case of matching the efficient tariff. It is a response to the South Australian pipeline being constructed adjacent to a Western System pipeline.

5.16.5 *Dandenong Bypass Tariff*

GasNet is aware of a proposal by Origin Energy to develop the Yolla offshore field in Bass Strait and to deliver this gas to Victoria by undersea pipeline. Current indications are that this gas will be processed at Lang Lang and delivered for injection into the main GasNet transmission pipeline at Pakenham.

It is GasNet's understanding that Origin plans to deliver up to 20 PJ/year (68 TJ/day) into the GasNet system from 2004. However, Origin has the option to extend their transmission pipeline to Dandenong, located approximately 29 km from Pakenham. Dandenong is the site of a number of large off-takes into the Origin distribution network. Origin has the opportunity to bypass both the GasNet system and the VENCorp gas market.

GasNet has estimated the cost of a bypass pipeline and associated regulators and metering facilities at Dandenong, and calculated a bypass tariff between Pakenham and Dandenong. This tariff exceeds the marginal long-run tariff through the GasNet system. Therefore, GasNet contends that this tariff will constitute a prudent discount.

The tariff will be implemented as an injection tariff at Pakenham and a discounted withdrawal tariff at Dandenong. The injection tariff is determined as a proportion of the Longford injection tariff, pro-rated on the distance between Pakenham and Dandenong. The remainder of the bypass tariff will be levied as a discount on the Metro withdrawal tariff. However this discount will only be available for withdrawals at the Dandenong off-takes.

The tariff is contingent on the project actually proceeding. There is no allowance in GasNet tariffs for the reduction in GasNet revenues which will result from this project.

Schedule 6 - Supply Forecasts

6.1 Longford Injection Zone

A large quantity of gas is contracted to the three incumbent Retailers from the ESSO/BHPP fields for the forecast period. However, there is a limit to the Maximum Daily Quantity (MDQ) which is available on any day. VENCorp has published its understanding of the level of this MDQ to 2005, and GasNet has maintained this level for the remainder of the forecast period. Based on the VENCorp APR, the MDQ is 830 TJ/day, falling to 810 TJ/day.

Gas will also be available from the Baleen/Patricia/Kipper fields. These fields are being developed in sequence, and a gas processing plant is being constructed at Orbost, for connection to the EGP. Gas will be back-hauled to Longford where it will enter the GasNet pipeline at Longford via a connection facility called VicHub, being constructed by Duke. GasNet has assumed a daily quantity of 35 TJ/day from this source.

There is a possibility that more gas can be supplied from these fields. However, GasNet has made an assessment that this is unlikely. This is because:

(a) there are ample supplies from other planned sources that can supply the forecast demand without additional supplies from Longford (that is, if Longford supplied additional gas on the peak period, then another supply source would have to be curtailed below our reasonable assessment of their production levels);

(b) the Bass Strait producers have access to new markets in NSW (via the EGP) and Tasmania (via the proposed Duke pipeline); and

(c) it is more economical for the Bass Strait producers to utilise existing peak supply capacity for high load factor loads in New South Wales or Tasmania, rather than increase their low load factor production into Victoria (current Longford load factor is 60% compared to desirable levels of 90%+).

6.2 Culcairn

Based on the VENCorp Annual Planning Review, it is understood that 28 TJ/day is currently contracted for injection at Culcairn. This corresponds to approximately 10 PJ/year at a 95% load factor. The capacity of the Culcairn delivery system is 50 TJ/day (92 TJ/day if the GasNet Bulla Park and Young compressors are maintained at their current locations on the EAPL pipeline).

The current 28 TJ/day of imports at Culcairn includes a contract for 14 TJ/day which GasNet understands ends in 2003. GasNet anticipates that the injection volumes will decline to approximately 17 TJ/day.

6.3 Yolla

Origin Energy is considering a proposal to develop the Yolla fields in the Bass basin approximately midway between Victoria and Tasmania. This proposal envisages a pipeline connection to the GasNet main transmission pipeline at Pakenham, approximately 29 km from Dandenong.

GasNet's assessment is that this project will not proceed, and no injections have been forecasted at Pakenham. This conclusion is based on the fact that significant reserves have been discovered in the Otway basin. These reserves are closer to shore than the Yolla fields and firm plans are in place to develop the Otway fields.

However, in the event that this project does proceed, a special injection and withdrawal tariff has been developed which will avoid a bypass risk between Pakenham and the GasNet off-takes at Dandenong.

6.4 Iona

Currently gas is injected into the SWP from the WUGS facility at Iona. However, as new fields are developed in the area, it is possible that new injection points in the vicinity of Iona will be developed to inject into the SWP. A reference to the Port Campbell Injection Zone is intended to refer to the aggregate of these adjacent injection points.

Iona accesses four sources of gas.

(a) The local on-shore fields around Port Campbell, which are currently producing around 25 TJ/day, and which are the subject of an on-going exploration and development program by Santos.

(b) The newly discovered off-shore gas resource of Thylacine and Geographe. The off-shore Otway basin resource, of which these fields are a part, is estimated to contain between 1000 PJ and 4000 PJ of gas. On current plans they will be producing by 2006. The developers are Origin Energy and Woodside.

(c) The Minerva and La Bella fields, owned by BHPP. The Minerva field is estimated to contain 300 PJ of gas. This resource has been contracted to South Australia from 2004, but it is expected that some production will be available for injection into the GasNet system, (although this is currently speculative).

(d) The WUGS facility. The WUGS storage and gas processing facility has a capacity of 10 PJ, and can inject at least 220 TJ/day into the GasNet system at a pressure of 10 MPa.

The Santos and Origin/Woodside resources are likely to be developed to produce at a high load factor in order to maximise the economic benefit of the developments. GasNet is forecasting that Santos will gradually increase production to approximately 55 TJ/day, before declining as production commences from Thylacine and Geographe. GasNet has forecast that Thylacine and Geographe will be producing 60 TJ/day in 2006 (20 PJ/year) and 90 TJ/day in 2007 (30 PJ/year). The actual field production levels will be considerably higher, with the bulk going to South Australia via the proposed Iona-Adelaide pipeline.

GasNet considers that these are relatively modest production scenarios. These volumes provide a minimal level of competition against Bass Strait gas, and are likely to be produced for this reason alone.

Based on the above-mentioned supply assumptions, there is a residual unsupplied peak day demand which is available from the WUGS and LNG facilities. GasNet expects that these storages will take the balance of the load. Given the peaky nature of the demand profile, the balance of unsupplied load requires an annual volume in the range of 3-5 PJ/year, but peak send-outs of 220-320 TJ/day. The storage facilities are purpose built to supply such peaky loads and it is extremely unlikely that base load field capacity will be developed to supply such high peak loads with such a low annual volume requirement.

Although there is adequate supply capacity available at Iona, the flows from Iona to Melbourne are limited by the capacity of the SWP. GasNet has assumed that some peak loads (most probably power generation) may be curtailed in 2006, but that the SWP is augmented in 2007 to carry the unmet demand from Iona.

6.5 Dandenong

Dandenong is the site of the LNG storage facility. The facility currently holds 450 TJ of gas as LNG under contract for use by retailers. The plant has the ability to inject (by vaporization) up to 150 TJ/day into the GasNet system.

The economics of use of LNG are determined by the very slow refill rate. Once LNG has been injected into the transmission system, the retailer cannot rely on it being replaced in the short term. Therefore, it is prudent for the holders of LNG stock to keep back some reserves to supply unexpected fluctuations in gas demand. For example, the occurrence of a 1:20 severe winter will add approximately 80 TJ to the peak day. GasNet has assumed that at least this amount will be held back for severe conditions, leaving 60-70 TJ/day for use in peak shaving. This amount is backed off the WUGS injections.

Schedule 7 - Injections and withdrawals from WUGS

MONTHLY (GJ):	Injections from WUGS to PTS		Withdrawals from PTS to WUGS (Refill)	
	2000	**2001**	**2000**	**2001**
Jan	456,250	468,076	0	48,857
Feb	1,073,462	428,162	14,915	2,543,021
Mar	2,010,950	325,042	28,559	2,612,141
Apr	3,477,608	723,613	0	820,394
May	2,549,829	896,067	4,855	153,874
Jun	2,555,838	1,472,678	18,936	24,217
Jul	1,969,705	1,647,873	20,849	55,352
Aug	2,165,953	1,679,934	0	25,799
Sep	1,132,826	1,120,924	51	253,922
Oct	988,246	507,719	49,295	323,157
Nov	285,323	46,078	123,667	176,443
Dec	419,396	117	2,310,935	232,150
Total for Year	**19,095,386**	**9,313,283**	**2,572,062**	**7,269,325**

NOTE: Injections include Santos production processed in the WUGS plant.
Withdrawals may not reflect total refill volumes as Santos production can be used without entering the PTS.
WUGS was emptied during 2000 and refilled from December 2000 through 2001.

Peak Injections from WUGS		
Peak Days	**Injections in 2000 (TJ)**	**Injections in 2001 (TJ)**
1	131	187
2	131	177
3	131	125
4	131	115
5	131	104
Average	131	142

Schedule 8 - List of recent Regulatory Decisions

Regulator	Reference	Regulated Entity	Decision	Date	Status
ACCC	ACCC, *Victorian Gas PTS Access Arrangement* (Final, 1998)	Transmission Pipelines Australia Pty Ltd & Transmission Pipelines Australia (Assets) Pty Ltd (**now GasNet Australia (NSW) Pty Ltd**); and VENCorp	Access Arrangement for the Victorian Principal Transmission System and Western Transmission System	6 October 1998	Final Decision
ORG	ORG, *Victorian Gas Distribution Access Arrangement* (Final, 1998)	Multinet Energy Pty Ltd & Multinet (Assets) Pty Ltd; Westar (Gas) Pty Ltd & Westar (Assets) Pty Ltd; and Stratus (Gas) Pty Ltd & Stratus Networks (Assets) Pty Ltd	Access Arrangement for the Victorian Gas Distribution System	6 October 1998	Final Decision
ACCC	ACCC, *NSW and ACT Transmission Network Revenue Caps Decision 1999/2000-2003/04* (Final 2000)	TransGrid; and EnergyAustralia Pty Limited	NSW and ACT Transmission Network Revenue Caps 1999/2000-2003/04	25 January 2000	Final Decision
IPART	IPART, *NSW Natural Gas System Access Arrangement* (Final, 2000)	AGL Gas Networks Limited	Access Arrangement for the Natural Gas System in NSW	21 July 2000	Final Decision
ACCC	ACCC, *MSP Gas Access Arrangement* (Draft, 2000)	East Australian Pipeline Limited	Access Arrangement for the Moomba to Sydney Pipeline System	19 December 2000	Draft Decision
ACCC	ACCC, *SMHEA Transmission Network Revenue Cap Decision 1999/2000-2003/04* (Final, 2001)	Snowy Mountains Hydro-Electric Authority	Snowy Mountains Hydro-Electric Authority Transmission Network Revenue Cap 1999/2000 - 2003/04	7 February 2001	Final Decision

Regulator	Reference	Regulated Entity	Decision	Date	Status
ACCC	ACCC, *ABDP Gas Access Arrangement* (Draft, 2001)	NT Gas Pty Ltd	Access Arrangement for the Amadeus Basin to Darwin Pipeline	2 May 2001	Draft Decision
OffGAR	OffGAR, *DBNGP Gas Access Arrangement* (Draft, 2001)	Epic Energy (WA) Transmission Pty Ltd	Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline	21 June 2001	Draft Decision
ACCC	ACCC, *SWP Revision Decision* (Final, 2001)	GPU GasNet Pty Ltd	Access Arrangement for the Principal Transmission System-Application for Revision by GPU GasNet Pty Ltd - SWP	29 June 2001	Final Decision
ACCC	ACCC, *MAPS Gas Access Arrangement* (Final, 2001)	Epic Energy South Australia Pty Ltd	Access Arrangement for the Moomba to Adelaide Pipeline System	12 September 2001	Final Decision
QCA	QCA, *Queensland Gas Distribution Access Arrangement* (Final, 2001)	Allgas Energy Limited; and Envestra Limited	Access Arrangement for the Queensland Gas Distribution Network	3 October 2001	Final Decision
ACCC	ACCC, *Queensland Transmission Network Revenue Cap Decision 2002-2006/7* (Final, 2001)	Powerlink	Queensland Transmission Network Revenue Cap Decision 2002-2006/7	1 November 2001	Final Decision

Schedule 9 - Extracts from Benchmarking Report

Figure 9-1: General & Administration Expense per Million Cubic Metres Delivered

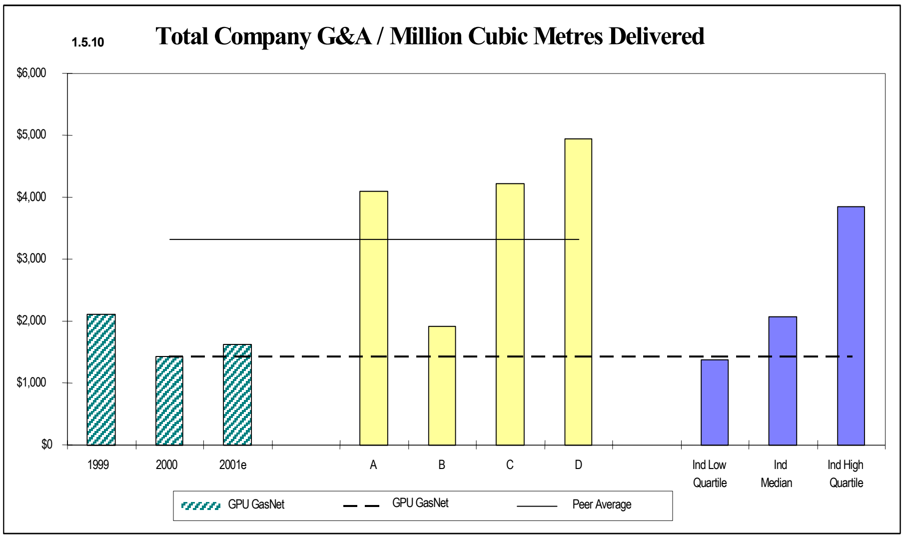


Figure 9-2: Measurement and Pipeline Expenses per Kilometre of Pipeline

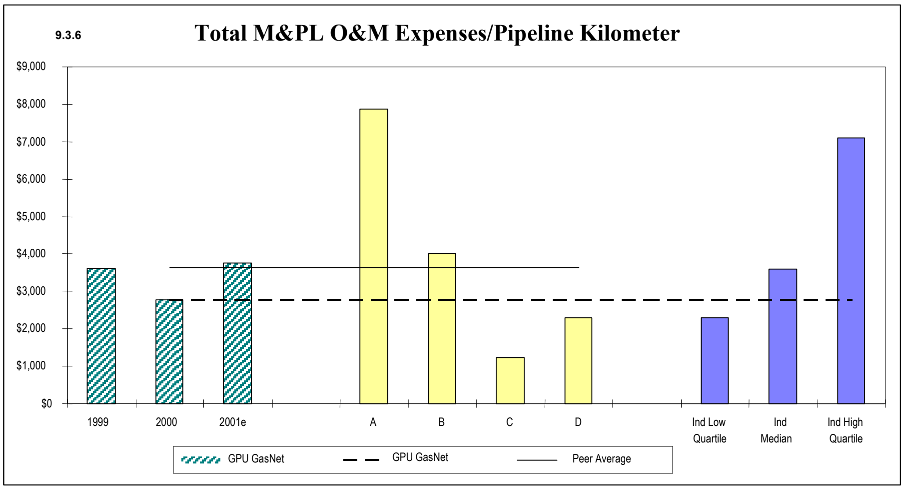
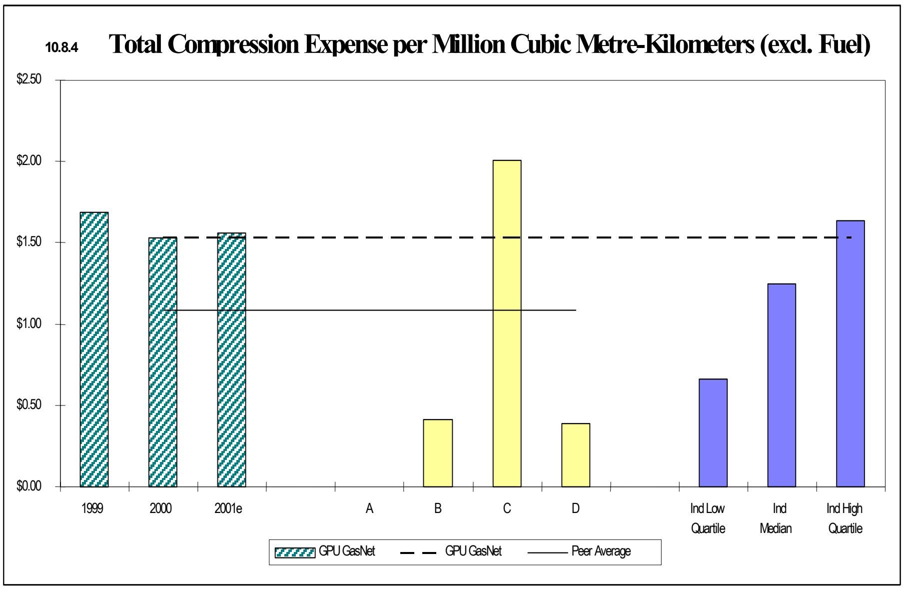


Figure 9-3: Compression Expense per Million Cubic Metres - Kilometres - excluding Fuel



GasNet Australia Access Arrangement - Submission

Annexure 1 - Extracts from relevant materials

Extracts from Tariff Order

9.2 What are the *fixed principles* to be used by the *Regulator* to decide price regulation arrangements for the *subsequent access arrangement period*?

(a) In making a price determination in relation to *tariffed transmission services* for the *subsequent access arrangement period*, the *Regulator* is to adopt the following *fixed principles*:

(1) utilise incentive-based regulation adopting a CPI-X approach and not rate of return regulation;

(2) set the X factor in the CPI-X formula so that only one X factor applies without revision for the entire *subsequent access arrangement period* to which the decision applies;

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

(A) all of the assets and liabilities of *TPA*;

(B) assets interdependent with a transaction pursuant to which all of the issued shares in or the assets and business of *TPA* cease to be held by or on behalf of the State of Victoria or a statutory authority; or

(C) assets pursuant to which the assets of *TPA* are sold and leased back to *TPA*;

(4) ensure a fair sharing between *TPA* and its *Customers* of the benefits achieved through efficiency gains if, in the *Initial regulatory period, TPA* has achieved efficiencies greater than the value implied by the value of XT, which is the X factor that applies to *TPA* under the CPI-X formula in the *initial regulatory period* (as defined in Part A of schedule 5) and, in ensuring a fair sharing of the benefits, may have regard to the following matters without limitation:

(A) the need to offer *TPA* a continuous incentive to improve efficiencies both in operational matters and in capital investment; and

(B) the desirability of rewarding *TPA* for efficiency gains, especially where those gains arise from management initiatives to increase efficiency;

(5) have regard to need to take into account the value of KT, (as defined in Part A of schedule 5) for the first year of the *subsequent access arrangement period*, as though that year represented *regulatory year* "t" for the purposes of applying the formula for KT;

(6) have regard to:

(A) the cost of making, producing or supplying the goods or services which *TPA* makes produces or supplies;

(B) any relevant interstate or international benchmarks for prices, costs and returns on assets in private sector industries comparable to those in which *TPA* operates; and

(C) the level of executive remuneration in *TPA* by reference to any relevant interstate and international private sector benchmarks for that remuneration;

(7) the *Regulator* may, in ensuring a fair sharing of the benefits of efficiency gains under clause 9.2(a)(4), choose to share the benefits referred to in that clause in the *subsequent access arrangement period*, both in the *subsequent access arrangement period* and in *access arrangement periods* after the *subsequent regulatory period*; and

(8) the *Regulator* may issue statements of regulatory intent which elaborate on how the *Regulator* will exercise its powers under clause 9.2(a)(4).

Extracts from GPU GasNet Pty Ltd
Application for Review of Access Arrangement

5 The System-Wide Benefits Test

5.1 System-wide benefits generally

In order to pass the System-Wide Benefits Test, the Regulator must be satisfied that a New Facility has system wide benefits which justify the approval of a higher Reference Tariff for all Users.

The concept of "system-wide benefits" has not been defined in the Code. GPU GasNet considers that this test involves the following key elements.

(a) The test is an objective one and requires the Regulator to form a reasonable view based on the information available.

(b) The assessment must be based on information that was available, and expectations that could reasonably be made, at the time a commitment to the relevant investment was made.

(c) The words "system-wide" suggest that a broad definition of beneficiaries should be adopted, namely that there should be benefits for a substantial portion of the customers whose gas is transported through the relevant system.

(d) Similarly, the concept of "benefits" should be given a broad interpretation and should include benefits such as:

   (i) enhanced system security (for example, a reduced risk of involuntary curtailments);

   (ii) enhanced system reliability (for example, the ability of the system to perform reliably during periods of peak demand); and

   (iii) enhanced competition (for example, introducing a new source of gas which is likely to provide benefits to customers in the form of greater price or service competition).

(e) Finally, in order to "justify" the approval of a higher Reference Tariff for all users, the Commission must be satisfied that the benefits expected to flow from the New Facility outweigh the costs of the increased tariffs.

GPU GasNet considers that the Southwest Pipeline satisfies these requirements. In particular, it provides enhanced system security and increased competition.

5.2 System-wide benefits - enhanced system security

In considering the system security benefits, two aspects need to be considered:

- the system security benefit provided in winter 1999; and
- ongoing system security benefits.

They are discussed in turn below.

(a) 1999 system security planning

The Longford fire and explosion of September 1998 destroyed a substantial part of the Esso Gas Plant No. 1 at Longford and associated infrastructure. In those circumstances, it was unclear what capacity would be available from Longford during winter 1999. Immediately following this incident, the Victorian Government initiated a number of projects to provide additional security of supply in light of the possibility that gas production at Longford might not return to full capacity before peak demands were experienced in winter 1999. The principal projects designed to secure additional gas from sources other than Longford were the Moomba-Melbourne Augmentation Project and the Southwest Pipeline.

The necessity for these projects was illustrated by the fact that as late as June 1999, Esso was not in a position to guarantee that gas supplies would be restored to sufficient levels[8].

The Southwest Pipeline was constructed at government direction under an accelerated schedule, and linked with accelerated field development work at North Paaratte, Mylor and Fenton Creek, and the installation of additional gas processing capacity at Iona. The entire project was designed to supply at least 100 TJ/day into the Principal Transmission System by winter 1999.

The Southwest Pipeline (supplying 100 TJ/day) and the Moomba-Melbourne Augmentation Project (supplying 92 TJ/day) together provided a delivery capacity of at least 192 TJ/day during winter 1999, sufficient to satisfy the bulk of the shortfall from Longford in the event that Gas Plant No. 1 did not return to production.

In fact, Longford did return to full production for winter 1999, but given the uncertainty associated with supply from Longford following the Longford fire and explosion, the Southwest Pipeline provided a critical element in the planning for system security for that winter. As such, the system security benefits of the Southwest Pipeline (and the Moomba-Melbourne Augmentation Project) were established in the planning for Winter 1999.

(b) Ongoing system security benefits

GPU GasNet considers that the Southwest Pipeline provides significant ongoing system security benefits.

Firstly, the Southwest Pipeline provides full back-up support to the Western Transmission System, which is currently supplied from North Paaratte at Port Campbell. If this or other local sources failed, the Southwest Pipeline could supply the entire needs of the system, either from the underground storage or from Longford.

Secondly, the Southwest Pipeline enhances the security of supply to Melbourne and country centres. The Southwest Pipeline can deliver at least 200 TJ/day into these demand centres from the underground storage and from the local fields at Port Campbell. This is a significant quantity when compared to a deliverability of 990 TJ/day from Longford. The Southwest Pipeline provides a high level of enhanced system security in the event of:

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[8] *"Gas supply not certain says Esso", The Age,* 12 June 1999, News page 5.

- a failure at the Bass Strait wells or gathering lines;
- a failure at the Longford gas processing plant;
- a failure of the Longford to Dandenong pipeline (which is un-duplicated for one third of its length); and
- a failure of the LNG facility during peak shaving operations (which is relied upon for up to 150 TJ/day).

The Southwest Pipeline supplements the security provided by the Interconnect and the LNG facility, but it offers a significantly greater quantum of protection. The security benefits can range from fewer involuntary curtailments during a partial supply failure (such as the "ice-plug" incident in June 1998), to the support of critical loads and the maintenance of minimum system pressure during a total supply collapse (such as occurred in September 1998).

5.4 Wide-wide benefit - increased competition

(a) Producer market power

A fundamental issue in gas reform in Victoria (and elsewhere) is the market power of the incumbent producers[9].

Esso-BHP has had a virtual monopoly on gas supply in Victoria for 30 years. The market power of Esso-BHP is still largely intact despite the extensive gas market reforms introduced by the Victorian Government. The Government created three competing gas retailers from the original Gascor entity, and allocated to each a share of the gas available under the on-going contract between Gascor and Esso-BHP (plus a gas release program to create a fourth retail competitor). This reform has the potential to set at least a cap on gas prices, based on commodity price competition between the retailers.

However, whilst the gas contracts make available a significant quantity of gas at a contract price to each of the three retailers, it is our understanding that there are limits to the amount of peak deliverability that is available. Given that the load in Victoria is very peaky and requires a firm supply, and given that firm peak deliverability from Esso-BHP is limited, it follows that Esso-BHP still retains considerable market power. In theory, in the absence of additional sources of peak supplies into the market, a producer in such a position may be able to use this market power to influence the price of gas and the growth of the gas market.

(b) Competitive forces

There is a perceived need for increased producer competition both between and within basins. Proposals for upstream reform have been considered, but it appears that these reforms will take some time to develop.[10]

[9] "The reforms implemented to provide pipeline access should drive greater competition in the downstream gas retail markets. However, the benefits of these reforms may be severely limited or not eventuate if there is a lack of competition upstream." Alan Asher. Paper delivered at APIA International Convention Nov. 1998.

[10] Such as procedures for allocation of exploration permits, revocation of authorisation of joint venture marketing and emergence of new producers.

In the shorter term, the most appropriate means to introduce competition to the gas supply market are:

- Connections to new gas basins: and
- Creating new sources of peak and seasonal supplies.

The Southwest Pipeline assists in both areas.

(i) Connections to new gas basins

Gas is currently being imported into Victoria via the Interconnect (and some exports have recently commenced). In the near future, the Eastern Gas Pipeline will export gas from Longford to NSW. These developments are expected to create competitive pressure on the commodity price of gas from Esso-BHP.

The Southwest Pipeline connects the Victorian market to the gas fields at Port Campbell. This allows gas owned by other producers to compete in the market against gas from Bass Strait, and further enhances the competitive pressures on Esso-BHP. There are good prospects for further gas field discoveries in the Otway Basin. Santos has developed the Mylor and Fenton Creek fields, and is currently marketing the newly discovered Penryn field. An intensive new exploration program is being planned.

The presence of the Southwest Pipeline (and a reasonable tariff on this pipeline) must act to stimulate further exploration in this region. In the absence of a pipeline connection to Melbourne, the likelihood is that small fields would not be economic to develop, and therefore exploration would not occur (small field developers could not afford to build a stand-alone pipeline connection to Geelong, nor could the Western zone absorb more than a small level of production).

The Minerva field is awaiting development, and this field could also utilise the Southwest Pipeline for carriage of some or all of the reserves to the Victorian demand centres. This field is permitted to BHPP, but to the extent that BHPP is distinct from the Esso-BHP Joint Venture in Bass Strait, there may be some prospect of further competitive pressure on Bass Strait.

(ii) Peak Supply

Currently firm gas supply on the peak day is obtained by use of the existing peak delivery rights under the Esso-BHP contract, plus use of LNG to shave the 'needle peak'[11]. These sources of peak supply are almost fully utilised, as shown in Annexure 3. Moreover it is our understanding that peak supply entitlements from Bass Strait will be reduced in 2001.

In the absence of adequate peak supplies, the retailers must source more gas from Moomba, purchase additional peak delivery rights from Esso-BHP at Longford, or purchase capacity in the underground storage.

The underground storage will be available in winter 2001 for withdrawals of up to 200 TJ/day. This facility is designed principally for seasonal supply during the winter. It is in direct competition with the peak deliverability provided by the Esso-BHP producers at Longford, and therefore significantly diminishes their market power. The Southwest Pipeline is essential to the prospects for the underground storage as a source of

[11] Plus a small contribution from Culcairn imports.

competition to Bass Strait. Moreover, a competitive tariff on the Southwest Pipeline is required to facilitate this competition.

(c) Summary

The Southwest Pipeline is principally an injection pipeline which connects a new source of gas to the main demand centres. This places it in a different category to a pipeline extension designed to serve new customers. An injection pipeline supplies gas into the Victorian gas market pool where it is available to all users. Hence the benefits from competitive pressures on the incumbent supplier are system-wide.

The Southwest Pipeline also stimulates exploration in the Otway region, particularly for smaller fields which individually could not economically justify the building of a dedicated connection to the market. Therefore more gas will be made available to the market, and competition will increase.

However, the main competitive benefit of the Southwest Pipeline is that it enables the underground storage to compete on a level playing field with the Longford supplier for seasonal and peak gas, and thereby places pressure on the market power of the incumbent producers in Bass Strait.

Unfortunately, it is not possible to predict the likely level of utilisation of a competitive injection pipeline (unlike an extension which is designed to serve known loads). The very existence of the pipeline ensures that competition will occur, but the results of that competition are unpredictable. For example, Esso-BHP could capture the majority of the load by offering the best price, and the utilisation of the Southwest Pipeline would be correspondingly low. However, in the absence of the pipeline, the price offered from Esso-BHP would be largely uncapped.

Therefore, the Southwest Pipeline can offer the significant benefits of enhanced competition. These benefits, in combination with system security benefits, are sufficient to justify the increase in the Longford injection charge, as demonstrated in section 5.6.

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Annexure 2 - NECG - Market Risk Premium (**Confidential**)

Important Note: This annexure is provided by GasNet to the Commission on a confidential basis

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Annexure 3 - NECG - Regulatory Treatment of Accelerated Tax Depreciation (**Confidential**)

Important Note: This annexure is provided by GasNet to the Commission on a confidential basis

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Annexure 4 - NECG - Imputation Credits (**Confidential**)

Important Note: This annexure is provided by GasNet to the Commission on a confidential basis

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Annexure 5 - NECG - Asset, Equity and Debt Beta (**Confidential**)

Important Note: This annexure is provided by GasNet to the Commission on a confidential basis

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Annexure 6 - Remaining Economic Life of GasNet's Transmission Assets, prepared by Saturn Resources (**Confidential**)

> ***Important Note: This annexure is provided by GasNet to the Commission on a confidential basis***

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Annexure 7 - Valuation of Non-Insured Risks prepared by Trowbridge (**Confidential**)

Important Note: This annexure is provided by GasNet to the Commission on a confidential basis