AlintaGas Networks

Access Arrangement Information

For the Mid-West and South-West Gas

Distribution Systems

Submitted 31 March 2004

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1 Introduction

1.1 Purpose of this Document

On 31 March 2004, AlintaGas Networks Pty Ltd (AGN) submitted to the Economic Regulation Authority (the Regulator) a revision to the Access Arrangement approved on 18 July 2000.

This Access Arrangement Information sets out further information to support the revisions, and seeks to assist the Regulator in forming its opinion as to the level of compliance of the Access Arrangement as revised in accordance with the provisions of the National Third Party Access Code for Natural Gas Pipelines (the "Code"). This Access Arrangement Information is submitted in accordance with section 2.28 of the Code.

In this Access Arrangement Information, unless the context otherwise requires, where a word or phrase is capitalised it has:

- the meaning given to that word or phrase in the Code; or
- the meaning given to that word or phrase in the glossary contained in Part A.

1.2 AlintaGas Networks

AGN is a wholly owned subsidiary of Alinta Networks Holdings. Alinta Networks Holdings is owned by Alinta Ltd, a publicly listed company owning approximately 74% and Diversified Utilities and Energy Trust, an infrastructure trust managed by AMP Limited owning approximately 26%.

AGN is the leading distributor of gas to Western Australian business and households with over 480,000 Delivery Points. As an independent business, AGN operates the Gas Distribution System (GDS) in the Mid-West and South-West of Western Australia, which is the subject of this Access Arrangement Information, in accordance with its obligations as a Service Provider under the Code. The AGN GDS is described in detail in section 6.

1.3 Overview of Submission

AGN submits this Access Arrangement Information under section 2.28 of the Code and, in doing so, considers that the Access Arrangement Information meets the requirements of sections 2.6 and 2.7 of the Code. Section 2.6 requires the Access Arrangement Information to contain such information as would enable Users and Prospective Users to understand the derivation of the elements in the proposed Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Code. Section 2.7 provides that the minimum information to be provided is the categories of information described in Attachment A.

AGN has provided both the minimum information required by Attachment A and a substantial amount of additional information. To facilitate the consideration of its proposed revisions by Users and Prospective Users, AGN has taken a broad interpretation of the class of information "which will assist Users and Prospective Users to understand the derivation of the elements in the proposed Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Code". AGN believes there is no further information which it could provide for this purpose and, as a consequence, AGN believes it has met the test set out in section 2.6 for the Code for the information requirements of the Access Arrangement Information.

AGN is proposing revisions to its Access Arrangement which describes the terms and conditions on which access is granted to the AGN GDS. The revisions proposed by AGN reflect an extensive examination of the experience gained from 5 Years application of the Code to AGN's assets and reflect consultation with Users to determine their experience of the Access Arrangement.

Key features of the revision include:

- **Workable Competition Approach.** AGN believes the Regulator must apply the Code in order to replicate "workable competition" and has structured its revisions accordingly. This means that where a range of plausible outcomes presents itself, AGN has selected (in accordance with how the Code should be interpreted according to the Supreme Court of WA) a point within the range consistent with the provision of efficient Services.

- **External Verification.** AGN believes the essence of the Regulator's role is to approve the proposed revisions if they are consistent with the Code. A key input into these deliberations will be how AGN's costs compare to other jurisdictions. As part of the revisions process, AGN commissioned expert consultants to benchmark its operations. The results are outlined in section 7 of this document but in summary the benchmarking information clearly demonstrates, that compared with other businesses, AGN is an efficient gas distribution business.

- **Incentive Mechanism.** AGN is proposing a revised Incentive Mechanism for the Second Access Arrangement Period. The Incentive Mechanism is based on a rolling ten Year period such that efficiency gains made would be retained for a full ten Years, regardless of when they are made in the Access Arrangement Period. AGN believes such a mechanism provides the optimal combination of efficiency incentives and benefit sharing with Users.

- **Introduction of Full Retail Contestability (FRC).** The revised Access Arrangement has been amended to cater for the introduction of FRC in the Western Australian gas market. This has resulted in additional costs being incurred or expected to be incurred by AGN, (which have been assessed as consistent with the Code), as well as changes to the Access Arrangement itself to ensure consistency with the Retail Market Scheme.

- **Regulatory Pass Through Mechanism.** AGN understands that the Economic Regulation Authority, like its predecessor the Office of Gas Access Regulation, will be funded on the basis of an industry levy. This mechanism has been justified on the basis that regulation ultimately benefits Users and Service Providers will pass the costs of regulation on to Users, however, this depends on Service Providers actually being able to pass costs on.

Reliance on forecasts of regulatory costs is likely to lead to under-recovery, as such costs are very difficult to forecast. This has been AGN's experience in the First Access Arrangement Period, with its forecasts of regulatory costs (which are all it was able to recover) being significantly exceeded by the actual costs levied by the Regulator. Consistent with the principle of Users ultimately bearing regulatory costs and the Code requirement that a Service Provider is able to recover the efficient costs of Service provision, AGN has introduced a regulatory cost pass through mechanism in its Second Access Arrangement. This pass through mechanism will allow the actual costs of regulation to be recovered every Year as an adjustment to Tariffs. AGN believes that this mechanism is compliant with the Code and notes that a regulatory cost variation component to Tariff changes has been adopted by the Victorian Essential Services Commission and applied to the Victorian Gas Distribution businesses.

- **Guaranteed Service Levels.** As part of its commitment to customer service, AGN proposes to introduce guarantees to Small Use Customers, which will see payments made to such Small Use Customers where AGN fails to meet pre-determined standards it sets.

1.4 Full Retail Contestability

AGN welcomed the policy of FRC introduced by the State Government in 2000 and has worked since then to accommodate the Government's target date of May 2004 for Full Retail Competition for all consumers.

The introduction of FRC and the proposed changes to the operation of the retail gas market in Western Australia, with AGN being required to be bound by an approved Retail Market Scheme under the Energy Coordination Act 1994, require revisions to the Access Arrangement:

(a) Amended Reference Service

Under the Retail Market Scheme, all Users consuming above 10 terajoules (TJ) of Gas at a Delivery Point in any 12 month period are required to have Telemetry installed at such Delivery Points. A new Reference Service, being Reference Service A2 has therefore been introduced where it is anticipated that an end use consumer will consume, or where an end use consumer is consuming 10 TJ but less than 35 TJ of Gas in any 12 month period.

(b) Consequential Changes to the Access Arrangement

AGN has amended its Access Arrangement to ensure consistency with the Retail Market Scheme.

AGN has also incurred, and is expected to incur, significant costs as a result of the introduction of FRC and considers it appropriate that these costs be recovered via the Access Arrangement as set out as follows:

(a) FRC New Facilities Investment

FRC New Facilities Investment associated with AGN implementing FRC has been estimated at $12 million. AGN has previously obtained approval from the Regulator[1] that these costs are reasonable and prudent and can be rolled into its revised capital base as part of the revisions to the Access Arrangement.

(b) Non-Capital Costs

AGN estimate FRC non capital costs to be $1.3 million per annum and has built these into its cost base for the 2005-2009 Access Arrangement Period. While there is no provision in the Code for the Regulator to issue a binding pre approval, the Regulator has indicated that this level of costs appears reasonable.

(c) Trigger Event Adjustment Approach

In addition to building in the above level of costs into its proposed revised regulated cost base, AGN has also proposed an adjustment mechanism that allows Reference Tariffs to be adjusted if actual FRC costs differ significantly from those forecast and AGN under recovers its FRC expenditure as a result.

1.5 Structure of Documentation

Documentation for this Access Arrangement revision comprises the Access Arrangement and this Access Arrangement Information.

1.5.1 Access Arrangement

The Access Arrangement comprises three sections:

- **Part A - The Principal Arrangements.** This sets out the principal policy statements in relation to Services Policy, Reference Tariffs and Reference Tariff Policy, Capacity Management, Queuing, Trading, Extensions and Expansion, and Interconnections Policies. It also includes Review and Expiry Arrangements for the next Access Arrangement Period and a Glossary applicable to both the Access Arrangement and the Access Arrangement Information.

- **Part B - Reference Tariffs and Reference Tariff Policy.** This Part sets out the details of the Reference Tariffs, the basis for their adjustment, Tariffs for Services other than References Services and the Reference Tariff policy used to determine a Reference Tariff. Part B also sets out the Fixed Principles that are to apply to the Access Arrangement.

- **Part C - Terms and Conditions.** This Part sets out the terms and conditions on which AGN will supply each Reference Service.

[1] *Final Decision: Recovery of costs associated with the introduction of Full Retail Contestability in the Mid-West and South West Gas Distribution Networks*, 1 October 2003

1.5.2 Access Arrangement Information

This Access Arrangement Information includes:

- information regarding the Reference Services and Tariffs and proposed Guaranteed Service Level scheme (GSL) arrangements that are to apply during the Second Access Arrangement Period;
- the basis on which the Total Revenue allowed under the Access Arrangement is calculated;
- the method for calculating initial Reference Tariffs and the method for variations to those Tariffs within the Second Access Arrangement Period;
- information regarding system capability and volume assumptions; and
- information regarding key performance indicators.

1.6 Contact Details

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2 Overview of Regulatory Decisions Impacting Access Arrangements and Judicial and Other Findings Impacting the Code

Apart from AGN's own experience with the operation of the Code over the past 5 Years, there have been Access Arrangements and revisions to Access Arrangements in other Australian jurisdictions, which give guidance to, or impact on, how the Code should be applied. AGN has undertaken a thorough analysis of decisions in other jurisdictions and believes its revisions are consistent with regulatory best practice emerging in Australia.

AGN believes that regulatory decisions themselves, while important, are less so than the following other significant developments which have profound implications for the application of the Code to Access Arrangements:

- Productivity Commission inquiries into the National Access Regime and the Gas Access Regime;
- Epic Energy Court case; and
- successful appeals against ACCC decisions on access pricing.

2.1 Productivity Commission Reports

The Productivity Commission has considered third party access generally in some detail in its *Review of the National Access Regime.*[2] In common with the later review of the Gas Access Regime (the findings of which are discussed below) it found that, while third party access could be justified, it also had significant costs which need to be taken into account.

A key finding of the review of the National Access Regime was that regulatory costs are unlikely to be symmetrical in the case of over versus under compensation. Regulation is a necessarily imperfect tool and getting outcomes exactly right is difficult. But in the case of error, it is worse to err on the side of under compensating regulated entities.

As the Productivity Commission put it:

> "Regulators must operate with limited information and imperfect regulatory tools. This implies that precise delineation after the event between genuine monopoly rents and balancing upside profits on successful projects will be well nigh impossible …"[3]
>
> "… the Commission accepts that there is a potential asymmetry in effects:
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> - "Over compensation may sometimes result in inefficiencies in the timing of new investment in essential infrastructure (with flow-ons to investment in related markets), and occasionally lead to inefficient investment to by-pass parts of a network. However, it will never preclude socially worthwhile investments from proceeding.

[2] Productivity Commission 2001, *Review of the National Access Regime*, Report no. 17, AusInfo, Canberra

[3] ibid., p. 82

- "On the other hand, if the truncation of balancing upside profits is expected to be substantial, major investments of considerable benefit to the community could be foregone, again with flow-on effects for investment in related markets.

"In the Commission's view, the latter is likely to be a worse outcome. Accordingly, it concurs with the argument that access regulators should be circumspect in their attempts to remove monopoly rents perceived to attach to successful infrastructure projects."[4]

Following its general assessment of third party access, the Productivity Commission commenced a detailed examination of the Code in June 2003. It released a draft report in December 2003[5], with a final report expected in mid 2004. It is likely that the Productivity Commission will be recommending changes to the Code and, while the timing of these is unclear, it is unlikely to happen before 2005 at the earliest. Nonetheless, the draft report does provide some clear signals as to problems with the Code as it currently stands and key areas for amendment.

Key conclusions from the report include:

"The Gas Access Regime … is at the more intrusive end of regulation"[6]

"There are significant compliance and administration costs in the operation of the Gas Access Regime."[7]

"The following overarching objects clause should be inserted into the Gas Access Regime:

"To promote the economically efficient use of, and investment in, the services of transmission pipelines and distribution networks, thereby promoting competition in upstream and down stream markets."[8]

"[The Code should be amended to state] that reference tariffs should … be set so as to generate expected revenue across a Service Provider's regulated services that is at least sufficient to meet the efficient long-run costs of providing access to those services."[9]

"[There is] inevitable imprecision and subjectivity that occurs when regulators are required to approve reference tariffs."[10]

"There is high potential for regulatory error when approving reference tariffs. The Gas Access Regime requires regulators to make decisions about future market circumstances that are uncertain. This has led regulators to use many debatable assumptions. There is a

[4] ibid., p. 83

[5] Productivity Commission 2003, *Review of the Gas Access Regime*, Draft Report, Canberra.

[6] ibid., p xxxvi

[7] ibid.

[8] ibid., p xxxvii

[9] ibid., p xliii

[10] ibid., p xliii

consequential tendency for regulators to seek additional information from Service Providers and further studies by consultants. This is unlikely to reduce uncertainty significantly."[11]

"… there is a strong likelihood that the incentive to invest and the nature and timing of investments in the Australian gas market have been affected by the Gas Access Regime."[12]

"Even if a regulator had all of the information held by a regulated business, it is unlikely that the regulator (or any other party, including the regulated business itself) would be able to determine precisely the most efficient prices/revenue."[13]

"… the most efficient revenue target cannot be known with certainty."[14]

"[The function of regulators is] to determine the level of costs within the range of feasible outcomes that is most consistent with the guiding principles for reference tariffs."[15]

"Implementing the WACC/CAPM approach is not a precise science, given the numerous debatable assumptions involved."[16]

"… a range of plausible values can be generated for the regulatory rate of return using the WACC/CAPM approach. This in turn implies that meeting the Gas Code's requirements does not automatically lead to a single indisputable number for a reference tariff."[17]

"… if regulatory error leads to reference tariffs being set below efficient costs, then the longer term outcome will be declining service quality and inefficient investment to meet future demand. Regulatory error is a real possibility …"[18]

2.2 Epic Case

In August 2002 the Western Australian Supreme Court handed down its decision in the matter of *Re: Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor*[19]. While the major focus of the decision related to the determination of the Initial Capital Base, a matter not directly relevant to AGN's proposed revisions, the Court also provided considerable guidance as to interpretation of the Code, and in particular the Regulator's role. The decision is the only judicial interpretation of what the Code means and should therefore be taken into account in any decision by the Regulator, particularly in Western Australia where the case arose.

The Court recognised the fundamental role of section 2.24 of the Code in guiding the Regulator's assessment of a proposed access arrangement. The Regulator must take into account:

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[11] ibid., p 255

[12] ibid., p xliii

[13] ibid., p 109

[14] ibid., p 200

[15] ibid., p 216

[16] ibid.

[17] ibid., p 234

[18] ibid., p 255

[19] *Re: Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor, [2002] WASCA 231*

- the Service Provider's legitimate business interests and investment in its pipeline system;
- firm and binding contractual obligations;
- safety and reliability;
- economically efficient operation of the pipeline system;
- the public interest;
- the interests of Users and prospective Users of the pipeline system; and
- any other matters the Regulator considers relevant.

The Court found that these seven factors were to be given weight as fundamental elements in the Regulator's assessment.

Furthermore, should the objectives for Reference Tariff Policy and Reference Tariffs as set out in section 8.1 of the Code conflict, these section 2.24 factors should be used for guidance in determining the manner in which such conflicts can best be reconciled or which of them should prevail.

In considering the objectives of section 8.1, consideration must be given to the efficient costs of delivering the Reference Service, to efficiency in the level and structure of the Reference Tariff, and to replicating the outcome of a competitive market. The Court was of the view that, while experts might differ as to the precise details, a reference to efficiency was a reference to economic efficiency. In addition, there was a close interrelationship between the role of a competitive market and the achievement of economic efficiency: competitive markets appear likely to lead, over time, to economic efficiency or at least to greater economic efficiency.

The Epic case made it clear that the Code's references to competition were to "workable competition" rather than perfect competition:

> "In simple terms [a workably competitive market] indicates a market in which no firm has a substantial degree of market power … a reference to a competitive market is to a workably competitive market…[20]"

> "In the particular context of the promotion of a competitive market for natural gas it would be surprising if what was contemplated was a theoretical concept of perfect competition … Workable competition seems far more obviously to be what is contemplated."[21]

> " …a reference tariff should be designed with a view to replicating the outcome of a competitive market ie. as indicated earlier, a workably competitive market."[22]

Having clearly established that competition referred to workable competition, the judgment then devoted some attention to what this may mean for application of the Code:

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[20] ibid., para 124

[21] ibid.

[22] ibid., para 143

"… the outcome of a workably competitive market is not capable of precise or certain calculation and at best, can only be approximated."[23]

"It appears to be inherent in this that in a workably competitive market past investments and risks taken may provide some justification for prices above the efficient level."[24]

"… [there is] a growing awareness of the long term disadvantages of striking the balance with too great an emphasis on the interest of consumers in securing lower prices, and without due regard to the interest of the Service Provider in recovering both higher prices and its investment."[25]

2.3 Regulatory Precedents

Finally, there have been two significant decisions by the Australian Competition Tribunal on the pricing principles applicable under the Code which have a direct bearing on how the Regulators should make Access Arrangement determinations.[26]

The Australian Competition Tribunal has found that the role of the Regulator is not to determine a correct return, rather it is to decide whether what is being proposed in the Access Arrangement is consistent with the Code:

"Contrary to the submission of the ACCC, it is not the task of the Relevant Regulator under s 8.30 and s 8.31 of the Code to determine a 'return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service'. The task of the ACCC is to determine whether the proposed AA in its treatment of Rate of Return is consistent with the provisions of s 8.30 and s 8.31 and that the rate determined falls within the range of rates commensurate with the prevailing market conditions and the relevant risk."[27]

2.4 Implications for Assessment of the Revisions

AGN believes that the collective impact of these decisions is to clarify the way in which the Code should be implemented and provide substantial guidance to the Regulator in assessing AGN's proposed revisions. At a general level, the overarching conclusion is that there is high potential for regulatory error which will carry substantial costs and regulators should act in a way to minimise these effects. This in turn means that regulators should not attempt to be too focused on the costs of Service Providers. Rather they should look at the extent to which the proposed revisions are consistent with the Code and if they are, then accept them.

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[23] ibid.,

[24] ibid., para 144

[25] ibid., para 145

[26] *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6; *Application by Epic Energy South Australia Pty Ltd* [2003] ACompT 5

[27] *Application by GasNet Australia(Operations) Pty Ltd* [2003] ACompT 6, para. 42

2.5 Standard to be Implemented

The Epic case made it clear that under the Code, regulators must aim to replicate a "workably competitive" outcome. This means that the efficiency standards imposed are not those of a theoretical construct of perfect competition but rather one that might be found in a real market and this may well allow higher costs than the theoretical ideal.

2.6 Regulatory Uncertainty

Both the Epic case and the Productivity Commission's reviews made it clear that even the best regulator (or for that matter, the business itself according to the Commission) cannot precisely determine the most efficient prices or revenue. As an independent report commissioned by the three Victorian distribution businesses found[28], the gas industry is exposed to a wide range of risks which can impact on outcomes. The Regulator therefore needs to recognise the inherent uncertainty in its decisions and allow for it.

In addition to this general conclusion, the Productivity Commission specifically noted difficulties determining a precise cost of capital figure.

2.7 Asymmetrical Costs

The uncertainty referred to above suggest that the Regulator is likely to err. But the Productivity Commission found that the economic costs of error differ between over and under compensating Service Providers. The latter is likely to be more costly and therefore the Regulator should err on the side of over compensation if it is clear that the result cannot be precisely determined, as is the case with the level of revenue and prices.

2.8 Function of Regulator

One of the key conclusions of both the Productivity Commission and the Australian Competition Tribunal concerns the function of regulators. It is abundantly clear that it is not, as some have argued, to determine an efficient level of costs for a given business. Rather it is to determine whether Access Arrangement proposals made by a Service Provider and, in particular, the level of costs proposed are consistent with the Code. Only if they are not is there then a legitimate function for a regulator to advance its own proposal and to determine an efficient level of costs.

AGN therefore submits that the Regulator, in assessing its proposed Access Arrangement revisions should take account of the imperfections in the regulatory framework identified above as part of its determination of whether the revisions meet the requirements of the Code. AGN believes it has submitted abundant evidence that its costs are at the lower end of those in Australian jurisdictions and, in these circumstances, under the Code the Regulator should approve the proposed revisions.

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28 Deloitte Touche Tohmatsu, *Valuation of Excluded Events*, April 2002

The Productivity Commission's findings on how regulators should conduct their assessment also drew attention to the significant costs involved in an overly intrusive regulatory process – costs that the Commission thought unlikely to be outweighed by any commensurate benefits from better regulatory outcomes.[29] One reason why more intrusive regulation is unlikely to result in better regulatory outcomes is that the Code, and the commercial environment faced by companies operating under it, places strong incentives on companies to operate in an efficient manner. Companies facing commercial incentives are unlikely to spend money without an expectation that it will make commercial sense, criteria, which the Code itself addresses, in areas such as section 8.16. In these circumstances, AGN submits that a reasonable approach to expenditure is that it is very likely to be efficient, given the incentives faced by privately owned companies, the fact that within Western Australia the provision of natural gas for consumption by Small Use Customers is not an essential service due to the alternative energy sources available and the low level of average annual consumption by Small Use Customers and the existence of very real competition from the Dampier to Bunbury Natural Gas Pipeline and Parmelia Pipeline in respect of commercial and industrial gas consumers.

In addition to these strong signals as to how the Regulator should undertake its assessment, AGN also submits that the Regulator must confine itself only to those matters allocated by the Code (and, in Western Australia, by the Gas Pipelines Access (Western Australia) Act 1998) to the Regulator in approving an Access Arrangement. Care must be taken that issues such as impact on end use consumers are considered only to the extent required by the Code and that areas more appropriately covered by Government policy, such as the retail price cap, do not intrude on the decision.

[29] Productivity Commission, *Review of the Gas Access Regime*, p xliii

3 Information Regarding Access and Pricing Principles

3.1 Introduction

In accordance with the relevant provisions of the Code, this section of the Access Arrangement Information:

- details the changes between the First and Second Access Arrangement Periods;
- describes the method by which Tariffs are determined;
- describes the Reference Services that AGN proposes to provide during the Second Access Arrangement Period;
- describes the rationale for the Terms and Conditions under which AGN proposes to provide these Services; and
- outlines the proposed GSLs that AGN will deliver over the course of the Second Access Arrangement Period.

3.2 Changes Between Access Arrangement Periods

With the introduction of FRC and the associated Retail Market Scheme it has been necessary for AGN to vary the Reference Services provided in the First Access Arrangement Period. A new Reference Service A2 is proposed to meet the requirement that Users with Delivery Points taking more than 10 TJ of Gas per Year are required to have Telemetry installed at the Delivery Point. Consequential amendments have been made to the existing Reference Service B1 by splitting it into a new Reference Service A2 and a revised Reference Service B1. These changes are discussed further in section 3.4.

The introduction of FRC and the Retail Market Scheme have also required amendments to be made to the Terms and Conditions upon which AGN will supply each Reference Service. The rationale for the proposed amendments to the Terms and Conditions is set out in section 3.9.

As part of the revisions proposed, AGN intends to move from a "simple price cap" form of regulation to a "tariff basket" approach. Tariffs proposed for the Second Access Arrangement Period have been calculated based on this approach. It is considered that the tariff basket approach encourages efficient behaviour and discourages inefficient behaviour in the delivery of Services and the provision of Extensions and Expansions to the AGN GDS. AGN supports this approach to the form of regulation provided that there is sufficient flexibility provided to enable the timely introduction of new Tariffs.

AGN's proposal for a "tariff basket" approach to the form of regulation is described in section 5.2

Ancillary Services are Services used in connection with the transportation and use of Gas. In the First Access Arrangement Period AGN offered four Ancillary Services. For the Second Access Arrangement Period, AGN proposes to offer no Ancillary Services. The rationale for AGN's position is set out in section 3.7.

3.3 Tariff Determination Method

The Reference Tariffs in the Access Arrangement have been designed to recover that portion of AGN's total revenue related to providing Reference Services delivered by means of the AGN GDS.

The Reference Services provided by means of the AGN GDS are:

- Reference Service A1;
- Reference Service A2;
- Reference Service B1;
- Reference Service B2; and
- Reference Service B3.

AGN will also provide an Interconnection Service as a non-Reference Service. Terms and Conditions for the Interconnection Service will be negotiated between AGN and the Interconnected Pipeline.

The above list is not exhaustive of the Services that AGN is prepared to make available. AGN will negotiate any other Service or element of a Service requested by a Prospective User.

The costs of providing Reference Services A1, A2, B1, B2 and B3 are to be recovered through Reference Tariffs A1, A2, B1, B2 and B3, respectively. The price upon which an Interconnection Service will be made available is to be negotiated by AGN and the Pipeline Operator to whom that Service is provided.

The structure of the Reference Tariffs is described in section 3.4 of this Access Arrangement Information.

Reference Tariffs A1, B1, B2 and B3 are determined from the current published price adjusted for the revised forecast total cost of providing Reference Services A1, B1, B2 and B3 and the revised volume and demand forecast of Reference Services A1, B1, B2 and B3 in the Second Access Arrangement Period. A Reference Service A2 has been developed to meet the requirements of the Retail Market Scheme.

Reference Tariff A2 has been calculated at the same rate as that calculated for Reference Tariff B1. Due to the requirement to install Telemetry, charges for User Specific Delivery Facilities will be increased for this additional cost.

The forecast total cost of providing Reference Services A1, A2, B1, B2 and B3 in the Access Arrangement Period is determined by subtracting the forecast cost of providing any other Services other than a Reference Service from the forecast cost of providing all Services by means of the AGN GDS in any particular Year. The forecast cost of providing all Services by means of the AGN GDS is provided in section 4 of this Access Arrangement Information.

Some Users who would otherwise have been charged Reference Tariff A1, A2, or B1, receive (or are to receive) a discount to the relevant Reference Tariff as described in section 5.4 of this Access Arrangement Information.

The components of the forecast total costs of providing Reference Services A1, A2, B1, B2 and B3 in the first Year, and in subsequent Years, of the Second Access Arrangement Period are set out in section 4 of this Access Arrangement Information.

Reference Tariffs designed to recover the forecast total costs for the first Year of the Second Access Arrangement Period are set out in Table 3.1 (current basis) and Table 3.1A (daily equivalent where appropriate).

Part B of the Access Arrangement sets out the pre-determined price path by which Reference Tariffs may be varied in the second and subsequent Years of the Access Arrangement. The price path, and hence the form of regulation, is described in section 5.2 of this Access Arrangement Information.

3.4 Reference Service/ Reference Tariff Structure

3.4.1 Reference Service A1/Reference Tariff A1

Reference Service A1 is a Service for Users requiring delivery of 35 TJ per Year or more of Gas at a Delivery Point in each Year of a Haulage Contract, and requesting a Contracted Peak Rate greater than or equal to 10 gigajoules (GJ) per hour. Users requiring Reference Service A1 tend to be those Users making efficient use of the AGN High Pressure GDS. For this group of Users, higher annual volumes tend to be associated with higher load factors.

The estimated number of Delivery Points for Users requiring Reference Service A1 is shown in Table 6.5 of section 6 of this Access Arrangement Information. The total volumes of Gas expected to be delivered at these Delivery Points in each Year of the Access Arrangement are shown in Table 6.4 of section 6.

Users requiring Reference Service A1 require that Service for the delivery of Gas to larger commercial and industrial installations. Their requirements for Service Pipes, regulators, Meters and associated facilities are generally specific to the installations to which AGN delivers Gas. Reference Tariff A1 has therefore been designed to recover from each User the cost incurred in using the AGN GDS. In addition Users are required to pay the cost of providing User Specific Delivery Facilities.

Relatively stable paths from Receipt Points to Delivery Points can be identified for Gas flows through the High Pressure System. The network assets used to deliver Gas to each Delivery Point at which a User takes Reference Service A1 can therefore usually be identified. As a consequence, the component of Reference Tariff A1 that recovers the cost of network use can be designed to recover the costs of installing, operating and maintaining the assets required to provide a User with Reference Service A1. The cost incurred by AGN in providing a User with Reference Service A1 is determined by:

- the location of the Delivery Point at which Gas is delivered to the User;
- the use the User makes of the Capacity of the AGN GDS; and
- the volume of Gas delivered to the User at the Delivery Point.

Reference Tariff A1 has therefore been designed to recover the cost of use of the AGN GDS through:

- a standing charge;
- a demand charge; and
- a usage charge.

In addition, Users will also be required to pay a charge for User Specific Delivery Facilities.

The values of the components of Reference Tariff A1 are set out in Table 3.1 in section .

The inclusion of a standing charge in Reference Tariff A1 is a recognition that the costs of installing, operating and maintaining the AGN GDS are largely fixed. It also serves the important purpose of ensuring that the structure of Reference Tariffs provides an appropriate signal for transfer from Reference Service A2 to Reference Service A1 as the volume of Gas delivered to a User approaches 35 TJ per Year.

The demand charge recovers that portion of the cost of use of the AGN GDS determined by the location of a User's Delivery Point, and by the use the User makes of the Capacity of the network. It is a charge for use of the AGN GDS measured as the product of use of Capacity and location. For the purpose of determining this charge, a User's use of Capacity is measured as the User's Contracted Peak Rate expressed in GJ per hour. Location is defined in terms of the distance, in kilometres, measured in a straight line, from the User's Delivery Point to the nearest transmission pipeline, irrespective of whether or not that pipeline is interconnected with the AGN GDS. The demand charge is, as a consequence, a charge per GJ per kilometre (km).

Use of distance to the nearest transmission pipeline as the measure of distance in the demand charge of Reference Tariff A1 is intended to mitigate the risk of inefficient by-pass of the AGN GDS.

The demand charge of Reference Tariff A1 is not a linear function of distance for a given Contracted Peak Rate. A declining block structure, with two distance-based blocks, has been adopted to provide better cost reflectivity in the Tariff. Users requiring Reference Service A1 for delivery of Gas to Delivery Points located at distances greater than 10 km from the nearest transmission pipeline are usually supplied at Delivery Points in urban fringe and rural areas. In these areas, the costs of pipe laying are lower than in more densely populated urban areas.

The usage charge of Reference Tariff A1 is a charge, which recovers that portion of the cost of use of the AGN GDS, determined by the User's location, and by the volume of Gas delivered to the User at a Delivery Point. It is a charge per GJ per km and, like the demand charge, has a distance-based declining block structure.

In addition to paying the demand and usage charges of Reference Tariff A1, a User of Reference Service A1 will pay a charge for Service piping, regulators, Meters and associated facilities. That charge will be User-specific, being determined by the costs incurred by AGN in connecting the User's facilities to the AGN GDS.

3.4.2 Reference Service A2/Reference Tariff A2

The Retail Market Scheme has been developed to facilitate the introduction of FRC in the Western Australian gas market. Under the Retail Market Scheme, all Delivery Points using more than 10 TJ of Gas in any 12 month period are required to have Telemetry installed, whereas historically, AGN has installed Telemetry equipment at Delivery Points taking 20TJs and above. The new requirement for a lower threshold facilitates the balancing and global settlement of gas flows into the AGN GDS under the Retail Market Scheme.

Reference Service A2 is a new Service for Users required by the Retail Market Scheme to have Telemetry installed, but which otherwise do not meet the requirements of Reference Service A1 because they require less than 35 TJ of Gas per Year at a Delivery Point, or having a Contracted Peak Rate less than 10 GJ per hour.

The estimated number of Delivery Points for Users requiring Reference Service A2 is shown in Table 6.5 of section 6. The total volumes of Gas expected to be delivered at these Delivery Points in each Year of the Access Arrangement are shown in Table 6.4.

Users requiring Reference Service A2 require that Service for the delivery of Gas to a wide range of commercial and industrial installations. These installations take between 10 TJ per Year and 35 TJ per Year. Users in this group taking a smaller annual volume, take Gas at Delivery Points on both the High and Medium Pressure/Low Pressure Systems. The largest part of the Medium Pressure/Low Pressure System is an integrated network supplied from over 120 points of interconnection with the High Pressure System. The pattern of Gas flow through the Medium Pressure/Low Pressure System varies continuously over time with variations in flow through the High Pressure System, and variations in the volume of Gas taken at Delivery Points.

Accordingly, the cost of providing Reference Service A2 is not, in general, directly related to the location of the User's Delivery Point and to the use the User makes of the Capacity of the AGN GDS. In Tariff design, the cost of providing Reference Service A2 must be, at least in part, related to the volume of Gas delivered to a User at a Delivery Point. The cost of providing Reference Service A2 will also include a fixed component because the costs of installing, operating and maintaining the AGN GDS are largely fixed.

Given Users of Reference Service A2 require that Service for the delivery of Gas to a broad range of commercial and industrial installations, their requirements for Service Pipes, regulators, Meters and associated facilities are generally specific to the installations to which they deliver Gas. They cannot be supplied using the standard facilities Reference Service B2 or Reference Service B3.

Reference Tariff A2 has therefore been designed to recover the cost of use of the AGN GDS through:

- a standing charge; and
- a usage charge.

In addition Users will be required to pay a charge for User Specific Delivery Facilities.

The standing charge for Reference Tariff A2, like the standing charge for Reference Tariff A1, not only recovers fixed costs. It also ensures that the structure of Reference Tariffs provides an appropriate signal for transfer from Reference Service B1 to Reference Service A2 as the annual amount of Gas delivered to a User increases.

The usage component of Reference Tariff A2 is a charge which recovers that portion of the cost of use of the AGN GDS determined by the volume of Gas delivered to a User at a Delivery Point.

3.4.3 Reference Service B1/Reference Tariff B1

As detailed above the introduction of the Retail Market Scheme has necessitated a new Reference Service for Delivery Points falling within the 10-35 TJ range. This means that Reference Service B1 as set out in AGN's First Access Arrangement Period has been circumscribed to Users requiring less than 10 TJ per Year at a Delivery Point, or having a Contracted Peak Rate less than 10 GJ per hour.

The estimated number of Delivery Points for Users requiring Reference Service B1 is shown in Table 6.5 of section 6. The total volumes of Gas expected to be delivered at these Delivery Points in each Year of the Access Arrangement are shown in Table 6.4.

Users requiring Reference Service B1 require that Service for the delivery of Gas to a wide range of commercial and industrial installations. These installations take between about 1 TJ per Year and 10 TJ per Year. Many of these Users take Gas at Delivery Points on the Medium Pressure/Low Pressure System and as noted earlier, the pattern of Gas flow through the Medium Pressure/Low Pressure System varies continuously over time with variations in flow through the High Pressure System, and variations in the volume of Gas taken at Delivery Points.

The majority of Users requiring Reference Service B1 require less than 10 TJ per Year at a Delivery Point and will therefore only require Meters to record volumes of Gas delivered.

Accordingly, the cost of providing Reference Service B1 is not, in general, directly related to the location of the User's Delivery Point and to the use the User makes of the Capacity of the AGN GDS. In Tariff design, the cost of providing Reference Service B1 must be, at least in part, related to the volume of Gas delivered to a User at a Delivery Point. The cost of providing Reference Service B1 will also include a fixed component because the costs of installing, operating and maintaining the AGN GDS are largely fixed.

Given Users of Reference Service B1 require that Service for the delivery of Gas to a broad range of commercial and industrial installations, their requirements for Service Pipes, the Regulators, Meters and associated facilities are generally specific to the installations to which they deliver Gas. They cannot be supplied using the standard facilities of Reference Service B2 or Reference Service B3.

Reference Tariff B1 has therefore been designed to recover the cost of use of the AGN GDS through:

- a standing charge; and
- a usage charge.

In addition Users will be required to pay a charge for User Specific Delivery Facilities.

The standing charge for Reference Tariff B1, like the standing charge for Reference Tariffs A1 and A2, not only recovers fixed costs. It also ensures that the structure of Reference Tariffs provides an appropriate signal for transfer from Reference Service B2 to Reference Service B1 as the annual amount of Gas delivered to a User increases.

The usage component of Reference Tariff B1 is a charge which recovers that portion of the cost of use of the AGN GDS determined by the amount of Gas delivered to a User at a Delivery Point.

3.4.4 Reference Services B2 and B3/Reference Tariffs B2 and B3

Reference Services B2 and B3 are Services for Users requiring delivery of smaller volumes of Gas at Delivery Points on the Medium Pressure/Low Pressure System. AGN has standardised, to the extent technically and commercially reasonable, the types of facilities it uses at these Delivery Points. In particular, the metering makes use of either a Standard 12 m^3/hr Meter, or a Standard 6 m^3/hr Meter. These Meters record aggregate volumes of Gas delivered between Meter readings, but not hourly or peak flows.

Reference Service B2 is a Service for Users supplying smaller commercial and small industrial consumers requiring delivery of Gas at a Delivery Point on the Medium Pressure/Low Pressure System, and requiring a Meter with a badged capacity of not less than 6m^3/hr and not more than 12 m^3/hr.

Reference Service B3 is a Service for Users supplying residential and smaller commercial and industrial consumers requiring delivery of Gas at a Delivery Point on the Medium Pressure/Low Pressure System, and requiring a Meter with a badged capacity of not more than 6 m^2/hr.

The estimated number of Delivery Points for Users requiring Reference Services B2 and B3 are shown in Table 6.5 of section 6 of this Access Arrangement Information. The total volumes of Gas expected to be delivered at these Delivery Points in each Year of the Access Arrangement are shown in Table 6.4 of section 6.

Reference Tariffs B2 and B3 have therefore been designed to recover the cost of use of the AGN GDS through:

- a standing charge; and
- a usage charge.

The standing charges of Reference Tariffs B2 and B3 are annual charges that recover fixed costs, including the costs of Standard Delivery Facilities. The standing charge for Reference Tariff B2 also ensures that the structure of Reference Tariffs provides an appropriate signal for transfer from Reference Service B3 to Reference Service B2 as the annual amount of Gas delivered to a User increases.

The usage charges of Reference Tariffs B2 and B3 are charges which recover that portion of the cost of use of the AGN GDS determined by the amount of Gas delivered to a User at a Delivery Point. These charges have a declining block structure that is intended to encourage use of Gas.

3.4.5 Changes to Reference Services

As outlined in sections 3.2 and 3.4, the Reference Tariffs have been changed to reflect changes to the cost of providing efficient Services and the introduction of the new Reference Service A2. As previously indicated, the introduction of the new Reference Service A2 is to cater for the Retail Market Scheme requirements that Telemetry be installed (which will constitute User Specific Facilities) at the Delivery Points using more than 10 TJ of Gas per Year.

From the commencement of the Retail Market Scheme, there will be a mechanism by which a User taking above 10 TJ of Gas at such a Delivery Point is required to install Telemetry. If the Reference Service being delivered to the User in respect of that Delivery Point under their existing Haulage Contract does not include the provision of Telemetry, the User shall, at the User's expense, either:

- apply for access to Reference Service A2 in respect of that Delivery Point, subject to the requirements of the Access Arrangement; or
- (unless AGN triggers a change to a User's Reference Service, see Section 3.4.6 below) request AGN to install Telemetry equipment on terms and conditions to be agreed in which case it will either continue access to the capacity on its previous Reference Service, and have a separate agreement in respect of the User Specific Delivery Facilities, or alternatively (if the treatment of the User Specific Delivery Facilities is incorporated into the Haulage Contract) continue access on what is now a Non-Reference Service.

3.4.6 AGN can initiate a change of Reference Service

Part A of the Access Arrangement now includes a mechanism by which AGN may require a User to change its Reference Service at a Delivery Point, if the User's Gas receipts at the Delivery Point fall outside the Gas flow parameters of the Reference Service or the User has been required under the Retail Market Scheme to install Telemetry. This provides flexibility for both parties, if Gas flows were incorrectly estimated prior to the commencement of the Haulage Contract.

The User has an opportunity to provide information regarding why the Reference Service should not be changed, and AGN must have regard to that information.

3.4.7 User can initiate a change of Reference Service

Part C permits a User to change Reference Services at a Delivery Point, refer below "Replacement Reference Service" in section 3.9.

3.5 Reference Tariffs

The Reference Tariffs determined in accordance with the policies described in the preceding subsections of this Access Arrangement Information are summarised in Table 3.1 and Table 3.1A. These Tariffs exclude the User specific charges for User Specific Delivery Facilities payable by Users taking Reference Services A1, A2 and B1.

TABLE 3.1: REFERENCE TARIFFS (EXCLUDING USER SPECIFIC CHARGES WHERE APPLICABLE)

(REAL JUNE $ 2003 INCLUSIVE OF GST)

Tariff	Block Structure	CURRENT 2004 PRICES			PROPOSED 2005 PRICES		
		Standing Charge $/Year	Demand Charge $/GJ-km/Yr	Usage Charge $/GJ-km	Standing Charge $/Year	Demand Charge $/GJ-km/Yr	Usage Charge $/GJ-km
A1	Standing First 10km >10km	47,565.2373	 196.3562 98.1781	 0.0479 0.0245	48,604.2536	 200.6454 100.3227	 0.0489 0.0244
A2	Standing First 5TJ Next 5TJ >10TJ	N/A	 NA NA NA	 NA NA NA	552.3176	 NA NA NA	 5.0893 4.8403 1.2476
B1	Standing First 5TJ Next 5TJ >10TJ	540.5106	 NA NA NA	 4.9805 4.7369 1.2476	552.3176	 NA NA NA	 5.0893 4.8403 N/A
B2	Standing First 100 GJ >100 GJ	216.2004	 NA NA	 5.5069 4.9610	220.9230	 NA NA	 5.6272 5.0694
B3	Standing First 15GJ Next 30GJ >45GJ	27.0177	 NA NA NA	 9.2398 6.4620 4.2495	27.6079	 NA NA NA	 9.4417 6.6032 4.3424

- NA = not applicable

Table 3.1A expresses that Table 3.1, where applicable, to an equivalent daily rate.

TABLE 3.1A: REFERENCE TARIFFS (EXCLUDING USER SPECIFIC CHARGES WHERE APPLICABLE)

(REAL JUNE $ 2003 INCLUSIVE OF GST)

Tariff	Block Structure	Current 2004 Prices			Proposed 2005 Prices		
		Standing Charge $/Day	Demand Charge $/GJ-km/Day	Usage Charge $/GJ-km	Standing Charge $/Day	Demand Charge $/GJ-km/Day	Usage Charge $/GJ-km
A1	Standing First 10km >10km	130.2265	 0.5376 0.2688	 0.0479 0.0245	133.0712	 0.5493 0.2747	 0.0489 0.0244
A2	Standing First 5TJ Next 5TJ >10TJ	N/A	 NA NA NA	 NA NA NA	1.5122	 NA NA NA	 5.0893 4.8403 1.2476
B1	Standing First 5TJ Next 5TJ >10TJ	1.4798	 NA NA NA	 4.9805 4.7369 1.2476	1.5122	 NA NA NA	 5.0893 4.8403 N/A
B2	Standing First 100 GJ >100 GJ	0.5919	 NA NA	 5.5069 4.9610	0.6049	 NA NA	 5.6272 5.0694
B3	Standing First 15GJ Next 30GJ >45GJ	0.0740	 NA NA NA	 9.2398 6.4620 4.2495	0.0756	 NA NA NA	 9.4417 6.6032 4.3424

- NA = not applicable

The approach to adjusting these Tariffs within the Second Access Arrangement Period is discussed in section 5.3 of this Access Arrangement Information.

3.6 Interconnection Service/Interconnection Tariff

An Interconnection Service is a Service provided to a Pipeline Operator in respect of the interconnection between a Sub-network and a Pipeline which is, or is to become, an Interconnected Pipeline supplying Gas to the Sub-network.

The Interconnection Service provides a right to interconnect with the AGN GDS. The terms and conditions and prices upon which an Interconnection Service will be made available are to be negotiated by AGN and the party to whom the Interconnection Service is provided.

There are currently three Interconnection Contracts in place with two separate Pipeline Operators. In each case there are specific issues to deal with and for this reason it is impractical to have a standard Tariff for the Interconnection Service. However the following generic issues need to be dealt with:

- the design, construction, commissioning, ownership and funding of Physical Gate Points and associated facilities;
- operational issues;
- management plans in respect of Gas quality, odorisation, metering and heating value management;
- reimbursement by the Pipeline Operator of AGN's capital and Non-Capital costs of implementing interconnection; and
- the Minimum Receipt Temperature for each Receipt Point

Consideration was given to a number of methods for recovering the capital and Non-Capital costs that AGN would incur as a result of the interconnection of a Pipeline. In particular, in relation to operating, monitoring and otherwise managing heating value management plans to comply with Declared Heating Value Regulations. Capital costs are likely to be in the range of $0.1m to $1m for equipment to take Gas samples from the AGN GDS at predetermined intervals and frequencies. Annual Non-Capital costs in the order of $0.1m to of $1m to model the network flows under a range of operating conditions, analyse the Gas samples supporting the modelling results and report compliance to the Office of Energy are also anticipated.

The implementation of heating value management plans would result in a benefit to those Users and Related Shippers associated with the interconnecting Pipeline at Sub-networks where the interconnection occurs. As the benefits are not available to all Users and all Sub-networks, it is not equitable for the costs to be allocated across the whole AGN GDS. Therefore these costs could not be recovered via the Reference Tariffs.

The introduction of the Retail Market Scheme means that the relationship between Users and Pipelines is now much more dynamic. Whereas during the First Access Arrangement Period AGN would have been able to predict with some stability which Users were injecting Gas from the interconnecting Pipeline and which were not, under the Retail Market Scheme Users' allocation instructions can be changed regularly and at short notice, and in addition Users can acquire swing services from either Pipeline on a day-by-day basis. Thus it is not practical or efficient for AGN to seek to recover these costs from only those Users who inject Gas out of the relevant Pipeline.

A person named in a User's allocation instruction for the sub-network under the Retail Market Rules is termed a "Related Shipper". AGN cannot seek to recover interconnection costs from the Related Shipper, as AGN does not have a direct contractual relationship with the Related Shipper. However, the Pipeline Operator seeking the Interconnection Service does have a direct contractual relationship with the Related Shippers transporting Gas for a User on that Pipeline and could recover costs from these parties in an efficient manner.

AGN's preferred mechanism is to seek recovery of the costs it incurs in relation to, or associated with, the Interconnection Service, directly from the Pipeline Operator seeking the Interconnection Service. Given that AGN has a direct contractual relationship with this party, AGN believes that this would be the most efficient recovery mechanism. Similarly, the Pipeline Operator could seek recovery of its costs from the Related Shippers transporting Gas for a User on that Pipeline as part of its contract with the Related Shipper.

3.7 Ancillary Services/Ancillary Service Tariffs

Ancillary Services are Services used in connection with the transportation and use of Gas. During the First Access Arrangement Period four Listed Ancillary Services were offered:

- Disconnection Service;
- Reconnection Service;
- Additional Meter Reading Service; and
- Additional Meter Testing Service

AGN proposes not to offer Ancillary Services during the Second Access Arrangement Period, as it believes the existing Ancillary Services no longer meet the requirements of the Code.

The Retail Market Scheme requires a large number of Services to be provided by a network operator upon request of a User. AGN proposes to publish a list of the Services (other than Reference Services), that it will offer along with the fee and the terms and conditions for each.

3.8 Incentive Mechanism

Under sections 8.44 - 8.46 of the Code, an Access Arrangement should contain an Incentive Mechanism. A "price path approach" is the Incentive Mechanism nominated in AGN's current Access Arrangement. In AGN's view this approach suffers from a number of deficiencies as an Incentive Mechanism, particularly the low level of incentives it provides for AGN and therefore, reduced User benefit. In Part B of its Access Arrangement, AGN proposes a new Incentive Mechanism to take effect from the Commencement Date.

The key features of this Incentive Mechanism are:

- **Multi-period Incentive Mechanism.** Consistent with the amendments to the Code in November 2001, the proposed Incentive Mechanism will operate for a period of ten Years or nominally two Access Arrangement Periods. This ten Year period equates to a 50:50 benefit sharing ratio between Users and AGN, when assessed on a net present value basis and, AGN believes, maximises total User benefit by providing the optimal combination of efficiency incentives and benefit sharing.

- **Rolling Incentive Mechanism.** Efficiency gains made will be retained for the full ten Years, regardless of when in the incentive period they are made. This means AGN will face the same efficiency incentives at the end of the incentive period as at the start. This contrasts with the current situation where, with a static mechanism, incentives are continuously eroded with the passage of time. Being able to keep efficiency benefits for ten Years regardless of when they are made clearly establishes different incentives to a static mechanism when only one or two Years efficiencies will be captured if they occur close to the end of the period.

AGN believes this revised Incentive Mechanism is consistent with the Code and with regulatory developments as outlined in section 2.

AGN is proposing this revised Incentive Mechanism on a prospective basis, to operate from the start of the Second Access Arrangement Period. The current Incentive Mechanism contains no provisions for carrying over efficiency benefits to the next Access Arrangement Period. Despite having made significant efficiency gains during the First Access Arrangement Period, AGN at this stage is making no provision for an Incentive Mechanism amount in its Second Access Arrangement financials.

3.9 Terms and Conditions

Section 3.6 of the Code requires a Service Provider to specify Terms and Conditions on which it will supply each Reference Service. These Terms and Conditions must, in the opinion of the Regulator, be reasonable.

AGN considers that the majority of the existing Terms and Conditions of the Access Arrangement for the First Access Arrangement Period are consistent with the requirements of the Code and have led to no disputes over access between AGN and Users. Apart from the changes below, and changes arising from the implementation of FRC, AGN proposes to continue with the existing Terms and Conditions as a basis for providing access to Users.

Several changes were required to be made to the Terms and Conditions as a result of the introduction of FRC and in order to ensure consistency with the requirements of the Retail Market Scheme, such as:

- **Metering Data.** Metering data may be now provided by AGN in accordance with the Retail Market Rules.
- **Balancing.** User’s must comply with the Gas balancing provisions of the Retail Market Rules.
- **Invoicing.** The procedure for disputing invoices under the Retail Market Scheme now applies to invoices issued under a Haulage Contract.
- **Dispute Procedure.** Disputes arising under the Retail Market Scheme must be dealt with under the Retail Market Scheme dispute resolution procedures and not under a Haulage Contract.
- **Provision of Information.** Information provided by a User to AGN is to be provided in an electronic form wherever possible.

- **Notices.** The format and procedure for notices specified in the Retail Market Scheme apply to a Haulage Contract.
- **Removal of Delivery Points.** Where a Haulage Contract has been terminated in respect of a Delivery Point, and the customer taking Gas at the Delivery Point has not transferred to another User, a User may request a Deregistration Service which, once completed, will permanently remove the Meter from the Delivery Point and terminate the User’s association with the Delivery Point. When the Delivery Point has been Deregistered, the User is no longer required to pay the applicable Charges for the Delivery Point, which it would otherwise continue to be liable to pay.

In addition to changes arising from the introduction of FRC, which AGN sees as the major scope change during the First Access Arrangement, proposed changes have also been made to the following areas of the Access Arrangement, none of which AGN regards as significant:

- **Replacement Reference Service.** As mentioned in Section 3.4.7 above, if a User acquires a Replacement Reference Service at a Delivery Point where it is already contracted to receive a Current Reference Service, then AGN will, at a User’s request remove the Delivery Point for the Current Reference Service from the Haulage Contract, provided that the provision of the Replacement Reference Service will not be less financially advantageous to AGN. This provision allows a User to request a more appropriate Reference Service for a Delivery Point during the term of its Haulage Contract, because for example, the quantity of Gas being delivered to the Delivery Point is significantly higher than expected. Therefore this clause provides flexibility for Users while protecting AGN's legitimate business interests.
- **Interconnection.** AGN has introduced additional provisions allowing it to recover the costs of interconnection from the operator of an Interconnected Pipeline. The rationale for this change is discussed at Section 3.6 above. Interconnection considerations, (together with removing the previous requirement that there be a direct link between the Delivery Point and Related Shipper, in order to facilitate a more flexible market under the Retail Market Scheme) have also generated additional changes to the curtailment provisions, where AGN may curtail on the basis of Users not having sufficient firm contractual entitlements on Interconnected Pipelines or curtailment by an Interconnected Pipeline.
- **Relationship between AGN and User.** AGN has amended its provisions in this area to specify the level of security a User must provide to secure its obligations under the Haulage Contract and the minimum level of insurance cover required. The amended Terms and Conditions also provide that a User must pay the amount of a Tariff for a Service even if AGN was unable to carry out the Service due to an act or omission of the User preventing AGN from carrying out that Service. The amendments also clarify that AGN’s ability to carry out a Service is subject to the User ensuring that AGN has unfettered access to the Meter. These changes are justified on the basis that they clarify the requirements on Users for AGN to be able to provide the Services.
- **Guaranteed Service Levels.** AGN has introduced a GSL scheme on the basis that this provides security to Small Use Customers that the high levels of service currently enjoyed will continue.

- **Curtailment.** Provisions have been added clarifying AGN's right in certain circumstances to refuse to accept or deliver Gas.

- **Interruptibility Provisions.** AGN has removed the interruption provisions that were in clause 20(1) of the First Access Arrangement as these do not relate to a Reference Service and may mislead Users into thinking that the Reference Services are provided on an interruptible basis. However, Users will still be able to approach AGN to negotiate an interruptible Service.

- **Commingling.** AGN has amended the commingling provisions to make it clear that AGN may commingle when necessary.

- **Novation of Contracts.** AGN has introduced a new clause allowing for novation of contracts with AGN's consent providing there is no increase in commercial or technical risk. This change allows for novation of contracts while at the same time protecting AGN's legitimate business interests.

- **Liability Regime.** The changes to the liability regime are designed to address an unintended deficiency in the previous wording, which could have inadvertently exposed the parties to extremely wide liability. It does not change the intended commercial effect. This new formulation is becoming widespread in the gas industry.

  In addition a clause has been added addressing what has recently emerged as network operators' potential liability to downstream consumers, such as occurred in claims arising from the Esso Longford fire. The rationale for this inclusion is as follows:

  - The usual commercial risk arrangement between a network operator and a User is (put very simply) that that the network operator's liability will be capped at direct damages. The User typically contracts with its consumer on a similar basis. That is, both the User and the consumer typically agree not to retain their right to indirect damages, consequential loss, lost production, etc. This is usual because network operators and gas suppliers simply cannot afford to underwrite the projects they supply.

  - A technical legal defect has emerged with the standard clauses designed to achieve this result (such as were included in the first Access Arrangement). The defect was shown up in some of the litigation following the Esso Longford fire, and leaves AGN exposed to a potential claim from a consumer for indirect loss including consequential losses.

  - In the Esso case (*Johnson Tiles Pty Ltd and ors. v Esso Australia and ors* (2203) Aust Torts Reports para 81-692.), the Court confirmed that a gas user further down the supply chain could sue someone further up the chain (there Esso, here AGN) directly in negligence, even though there was no contractual relationship between them. In addition, depending on the circumstances of a particular interruption, the consumer may be able to prove a sufficient duty of care in AGN that AGN became liable for "pure economic loss" such as lost production (*Caltex Oil v. The Dredge "Willemstad"* [1976-77] 136 CLR 529). AGN does not suggest that it would be straightforward or likely for a consumer to succeed in such a claim, but the risk is there and (as Esso can attest) it is more than just a theoretical one.

  - AGN wishes to ensure this risk is covered, in a manner consistent with the basic commercial principles outlined above.

- The problem is that the current contractual release given by the User to AGN, releasing it from liability for Indirect Loss, would not assist AGN in an action brought against AGN by a third party such as a customer. Thus, assuming a case could be made out against AGN, the customer might be able to pursue AGN directly for consequential losses or lost production arising from a gas supply interruption, even though that is not consistent with the normal commercial position.

- AGN has therefore proposed an indemnity from the User to AGN, protecting it against claims from downstream consumers. The User would no doubt include a similar provision in its gas supply agreements, passing the risk back to the consumer, who has traditionally been regarded as the best person to bear the risk.

- **Exceeding Contracted Peak.** The terms and conditions for Reference Services A1 and A2 contain additional provisions concerning the situation where Contracted Peak Rate is exceeded and introduce an Overrun Service in such circumstances and also provide for procedures to increase the Contracted Peak Rate or install flow protection devices where necessary. The changes strike a balance between protecting AGN's legitimate business interests in a relatively stable and predictable system and allowing the possibility that Users may need to exceed their Contracted Peak Rate on occasion.

AGN considers that by adopting this minimal change approach:

- the Terms and Conditions proposed will continue to be seen as consistent with the requirements of the Code;
- the likelihood of disputes about the Terms and Conditions of access will be minimised;
- existing knowledge and understanding among Users and AGN will be retained and assist in improving consistency of application going forward;
- changes to systems and processes will be minimised, and
- transitional issues in moving to new arrangements will be minimised.

3.10 Guaranteed Service Level Scheme

3.10.1 Proposed Scheme

Traditionally the performance of energy service providers in delivering services to customers has been measured at a “whole of customer level” with little concern about the level of service to individual consumers. Recent regulatory decisions in some Australian jurisdictions have seen the introduction of financially based service performance incentives for gas and electricity service providers, as well as GSL schemes delivering direct benefits to individual consumers.

GSL schemes are structured to provide an appropriate incentive to the Service Provider to ensure that the level of service delivered to individual end use consumers is not materially less than the high level of service reliability delivered, on average, by the network as a whole. Where the Service Provider fails to deliver prescribed services within predetermined service levels, payments are made by the Service Provider to consumers.

AGN's GDS has displayed a very high degree of customer service and reliability during the First Access Arrangement Period and AGN believes customer satisfaction amongst end use consumers to be high. AGN is not aware of the existence of any significant reliability or service issues or of any such issues being likely to arise in the Second Access Arrangement Period.

While gas is a fuel of convenience, rather than an essential service, given the importance of reliability of supply to end use consumers, AGN believes there is merit in introducing a GSL scheme for Small Use Customers. The GSL scheme described below sets out AGN's commitment to ensuring that Small Use Customer service levels, on which it impacts as network operator, continue at the current high levels in line with AGN's corporate values.

AGN also proposes that the GSL scheme would be implemented in a manner that preserves the economic value of a business that continues to meet its service targets at a network-wide level, as well as at the individual end consumer level.

AGN has developed the GSLs based on the following factors:

- Small Use Customers satisfaction levels and historical complaints;
- the aim of positively reinforcing the provision of satisfactory service to end consumers using less than 1 TJ/annum;
- the need for the GSL scheme to be simple and comprehensible; and
- the need for the costs of administering the GSL scheme to be minimised.

It is considered that the most appropriate GSLs for a network operator following the introduction of FRC are those focused upon the more common direct interfaces between AGN and Small Use Customers, as well as those events that have the greatest potential to cause inconvenience to end consumers.

On this basis, the following events were identified as relevant for GSLs:

- organising appointments where there is a loss of supply or a gas leak;
- seeking connection at an established home;
- repeat interruptions to the same Delivery Point; and
- lengthy interruptions to the supply of Gas to the Delivery Point.

GSL payments have been set at levels which, when considered in conjunction with the costs of their administration, would provide appropriate incentives to AGN to continue satisfactory levels of service.

Accordingly, the GSLs for the Second Access Arrangement Period are as follows:

- **Appointments.** If a Gas main or Service is broken in the street or garden and there is a strong smell of Gas, a contractor will be on site within one hour of the agreed time. If Gas supply is lost through an AGN fault or emergency, a contractor will arrive within three hours of the agreed time. If AGN is more than 15 minutes late for such an appointment, AGN will pay the Small Use Customer an inconvenience fee of $25.
- **Connections.** AGN will install a Gas Service and Meter where a Gas main runs past an established home within five business days of notice from a licensed gas retailer. Where AGN fails to do this, AGN will pay Small Use Customers $40 for each additional day later to a maximum of $120.
- **Repeat Interruption.** If Gas withdrawn at a Delivery Point by or in respect of a Small Use Customer is the subject of more than four unplanned interruptions in a Calendar Year and those unplanned interruptions arise as a consequence of a Fault in the GDS, then AGN will pay that Small Use Customer $100 for each subsequent unplanned Interruption in that calendar Year.
- **Lengthy Interruptions.** If supply at a Delivery Point at which Gas is withdrawn by or in respect of a Small Use Customer is interrupted for more than 12 continuous hours as a consequence of a Fault in the GDS, then AGN will pay that Small Use Customer $80.

The proposed GSLs apply to AGN’s GDS and Services provided by AGN and its agents acting under AGN’s direction for Small Use Customers. The proposed GSLs do not apply to:

- customers other than Small Use Customers;
- Force Majeure Events;
- planned interruptions effected with the prior agreement of, or appropriate notice to an end consumer;
- events occurring downstream of the meter;
- events occurring in a transmission pipeline or natural Gas production facility; and
- interruptions caused by third party or consumer interference.

The arrangements under which GSL payments will be made to Small Use Customers are set out in the Terms and Conditions of the Access Arrangement.

3.10.2 Expected cost of GSL payments

Costs associated with the introduction of the proposed GSL scheme include initial establishment costs, plus on-going operating costs in the form of the expected value of payments to be made under the GSL scheme. These on-going costs have been incorporated into AGN's operating cost benchmarks for the Second Access Arrangement Period. Given the time necessary to establish the GSL scheme, AGN anticipates introducing it on 1 July 2005. With the exception of establishment costs, which will be incurred from the commencement of the Second Access Arrangement Period, GSL costs for the first Year are expected to apply for only the second half of that Year.

Detailed information relating to the estimation of the number of GSL payments are set out below. In the case of each GSL, estimates have been based on past experience and the limited data presently available.

(a) Late Appointment

AGN estimates that it has a total potential number of appointments of approximately 2,600 per Year. It is estimated that on 98% of all occasions, AGN would meet or exceed the required service standard. On this basis, AGN would expect to make GSL payments relating to 2% of its total appointments. At a rate of $25 per GSL payment, the total annual payment is estimated to be $1,300 per annum.

(b) Connections

Approximately 4,000 Small Use Customers on line of main are connected to AGN's GDS each Year. AGN considers that a reasonable initial benchmark target for this GSL would be 90% of new connections executed on time. Assuming that 10% of connections are not completed within the agreed 5 days then approximately 400 connections will be subject to a GSL payment each Year.

It is further assumed that where new connections are not provided within two days of the agreed date, then the average GSL payment would be for the amount of $80, being the average of the minimum of $40 for one day and the maximum payment of $120 for three days. The total GSL payments assumed therefore are 400 at a cost of $80 each, resulting in an annual total payment of $32,000.

(c) Repeat Interruptions & Lengthy Interruptions

Costs and inconvenience to Small Use Customers during supply interruptions will be exacerbated if supply is not restored within a reasonable time. It is therefore appropriate to set high levels of performance against these GSLs. Accordingly, a target in excess of 99% achievement have been set in relation to repeat interruptions and lengthy interruptions. The potential GSL payment that may arise is estimated to be $70,000.

(d) Establishment costs

There will also be establishment costs associated with the introduction of a GSL scheme. These include costs relating to development and implementation of business and performance monitoring processes, modification of existing information technology systems and training of operational staff. AGN has estimated the establishment costs of this scheme to be $150,000 and has therefore included this cost in the forecast of capital expenditure.

3.11 Regulatory Cost Pass Through

As part of the tariff basket approach, Total Revenue will vary by CPI-X + R, where X is the price adjustment factor to smooth prices over the Access Arrangement Period. R is an adjustment to reflect the actual level of regulatory costs incurred by AGN and thus allow regulatory cost recovery.

This regulatory cost recovery mechanism is required on the grounds that regulatory costs are very difficult to forecast. During the First Access Arrangement Period, an allowance was made for forecast regulatory costs but actual costs exceeded this significantly. As a result, AGN under-recovered regulatory costs during this period. AGN anticipates similar difficulties in accurate forecasting of regulatory costs during the Second Access Arrangement Period. Consistent with the Code principle that efficient costs should be recovered via the access arrangement, the regulatory cost recovery mechanism will allow AGN to recover its actual costs of regulation.

4 Total Revenue

4.1 Introduction

This section sets out the approach that has been used to calculate the Total Revenue for the Second Access Arrangement Period. The Total Revenue has been calculated to meet the general principles and objectives set out in clause 8.1 of the Code and as interpreted by the WA Supreme Court and the Australian Competition Tribunal. Those objectives include:

- providing AGN with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Services over the expected life of the assets used in delivering those Services;
- replicating the outcome of a competitive market;
- ensuring the safe and reliable operation of the GDS; and
- not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries.

Total revenue is established using the formula given below:

$$TR = AV * WACC + D + OC + NWC * WACC + ICM$$

where:

TR	=	Total Revenue
AV	=	Asset value (the total value of assets employed in providing services)
WACC	=	Pre-tax Weighted Average Cost of Capital
D	=	Return of Capital
OC	=	Non-Capital Costs
NWC	=	Net working capital, and
ICM	=	Incentive Carryover Mechanism Amount.

ICM is forecast to be zero in the Second Access Arrangement Period, however, the multi period Incentive Mechanism proposed will require it to form part of future calculations.

The method used to calculate the return on and return of assets is based on real asset values and a real pre-tax weighted average cost of capital.

Unless otherwise stated all monetary values, consistent with section 8.5 and 8.5A of the Code are expressed in real terms - real value applied is June 2003. The basis of expressing all monetary values in real terms is to make comparatives and forecasts more transparent. June 2003 has been chosen on the basis that at the time of preparing this document and the relevant analysis, June 2003 data was the latest available.

Sections 4.2 and 4.3 below provide further detailed information in relation to each key component or "building block" of the Total Revenue with a summary of the composition of Total Revenue set out in section 4.3.10.

4.2 Capital Base Value

4.2.1 Initial Capital Base

The value of the AGN GDS, excluding the value of User Specific Delivery Facilities, as approved by the Regulator in its final decision on 30 June 2000, of $535.9m at 31 December 1999 is recognised as the Initial Capital Base. This is consistent with sections 8.8 – 8.14 of the Code.

4.2.2 Asset values for each category of asset

AGN has considered all of the factors listed in sections 8.9 and 8.10(a) – (j) of the Code in establishing the Capital Base of the AGN GDS for the purpose of determining Reference Tariffs for Reference Services for the 2005 – 2009 period. This calculation meets the requirements of these clauses of the Code.

Following the sale of AGN by the State of Western Australia, a detailed asset register has been developed. The opening values (as at 1 January 2000) have been matched to the values determined by the Regulator's final approval of the Access Arrangement, dated 13 July 2000.

For each Year of the First Access Arrangement Period the Initial Capital Base has been adjusted to reflect:

- actual new capital expenditure net of any contribution made by consumers (including a forecast for 2004) meeting the requirements of section 8.16 of the Code has been added to the Initial Capital Base;
- the forecast regulatory Depreciation (Return of Capital) as detailed in the Regulator's final approval of the Access Arrangement, dated 13 July 2000, has been deducted from the Initial Capital Base;
- disposals at the regulatory written down book value has been deducted from the Initial Capital Base value; and
- changes in the Capital Base as a result of inflation, with adjustments made to bring all asset values to June 2003.

Table 4.1 below provides a summary of the value of the Capital Base for each Year of the First Access Arrangement Period.

TABLE 4.1 - VALUE OF THE CAPITAL BASE DURING THE FIRST ACCESS ARRANGEMENT PERIOD

(REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2000	**2001**	**2002**	**2003**	**2004**
High Pressure Mains	169.2	169.3	167.6	165.8	164.0
Medium Pressure Mains	202.6	201.6	201.6	201.3	200.1
Med / Low Pressure Mains	108.8	107.4	104.8	102.2	99.6
Low Pressure Mains	30.6	29.6	28.6	27.5	26.3
Secondary Gate Stations	2.2	2.1	2.0	1.9	1.8
Regulators	10.8	10.5	10.1	9.7	9.2
Meters & Service Pipes	67.9	72.2	84.8	99.9	110.0
Equip & Vehicles	18.3	15.3	11.5	7.6	4.0
Land & Buildings	7.2	7.4	7.4	7.4	7.4
FRC	0.0	0.0	1.8	3.0	12.0
Total	617.6	615.4	620.2	626.3	634.4

4.2.3 Capital Expenditure during the First Access Arrangement Period

AGN considers that it is reasonable for the Regulator to infer that the capital expenditure during the First Access Arrangement Period meets the Code's requirement.

Section 8.16 of the Access Code states;

> "The amount by which the Capital Base may be increased is the amount of the actual capital cost incurred (New Facilities Investment) provided that:
>
> a. that the amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services; and
>
> b. one of the following conditions is satisfied;
>
> i. the Anticipated Incremental Revenue generated by the New Facilities exceeds the New Facilities Investment; or
>
> ii. the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or
>
> iii. the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services."

AGN notes that an examination of the First Access Arrangement Period's capital expenditure would be a time consuming and costly process. Under the Code a Service Provider can only invest in capital where it passes the Economic Feasibility Test (EFT) of Section 8.16. As a privately owned company AGN faces ongoing and constant scrutiny of both capital and Non-Capital costs. AGN notes that regulators elsewhere have used these circumstances to conclude that past capital expenditure should prima facie be seen as efficient. Given the incentives faced to achieve efficient levels of capital expenditure, coupled with the effectively mandatory nature of a significant component of the capital budget, AGN questions whether any further examination of these costs is justified.

AGN has spent more capital expenditure in the First Access Arrangement Period than was projected in the First Access Arrangement Information as shown in Table 4.2 below.

TABLE: 4.2 - REGULATORY FORECAST AND ACTUAL CAPITAL COSTS FOR 2000 – 2004

(REAL $ MILLION JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2000	2001	2002	2003	2004
Regulatory forecast	28.6	22.4	18.9	18.5	15.5
Actual Cost	27.8	18.2	26.0	27.9	30.7

Note: 2004 Actual cost has been based on a forecast including FRC

The regulatory forecasts are inconsistent with the actual level of efficient expenditure incurred during the First Access Arrangement Period, particularly the increase in connections made during this period and the costs incurred to comply with the introduction of FRC.

AGN also notes that, consistent with the incentive regimes of the Code, it has not earned a full return on its investment for those capital expenditures incurred above the regulatory forecasts. Notwithstanding the comments made above, the increase in capital expenditure in the First Access Arrangement Period has been incurred due to investment to comply with the introduction of FRC, and growth in consumer connections.

- **Full Retail Contestability.** To comply with the introduction of FRC AGN has forecast to spend $12m, with a significant amount of this expenditure to be incurred in 2004. AGN notes that the Regulator has already approved this amount as being prudent and efficient in its Determination dated 1 October 2003. AGN seeks to include this amount into the regulated asset base starting from 1 January 2005 with any variances to the $12m adjusted in the Third Access Arrangement Period, as provided for in the Fixed Principles in Part B of the Access Arrangement.

- **Consumer Connections.** A significant amount of expenditure has been incurred in the provision of connecting consumers to the AGN GDS. Consistent with section 8.16 of the Code, AGN has developed a process to ensure that connections meet the EFT. This process is based on an assessment using discounted cashflow methodology. If the capital investment can be recovered over a reasonable term and return a positive net present value, then the investment proceeds. If there is a shortfall, a contribution will be sought or the capital investment does not occur. The exception to this is where an end use consumer on line of main seeks a connection and even though the economic evaluation may not result in a positive NPV, the cost of connection does not exceed $650. AGN has an obligation to connect in these circumstances under its Distribution Licence. The costs of connecting commercial consumers requiring specific metering and delivery facilities are captured separately as User specific charges. This form of capital investment has not been included in the regulated asset base.

The First Access Arrangement Period forecast the number of connections to be approximately 78,000 over the five Year period. This compares to approximately 98,000 (including 2004 forecast) actually made, an overall increase of 20,000 connections.

Based on the analysis prepared above the overspend (over the regulatory forecasts) in connections is approximately $29m consisting of:

- $10m – actual connections made above regulatory benchmarks; and
- $19m – actual unit rate paid above regulatory benchmarks.

Connection numbers were higher than forecast predominantly due to the introduction of the Federal Government's first homebuyer assistance scheme and other economic factors outside AGN's control, which led to a higher approval for new dwellings. This has resulted in a higher number of connections made over the five-Year period. In addition there has been an increase in multi unit redevelopment on existing property particularly in the older suburbs of Perth.

Expenditure per connection is consistent with industry best standards and is more favourable than unit rates paid on the eastern seaboard of Australia. The amount has been benchmarked internationally by consultant GTL International (refer section 4.3.11).

4.2.4 Regulatory Treatment of Redundant Assets

Clause 8.27 of the Access Code states:

> "Before approving a Reference Tariff which includes such a mechanism [for removal of redundant capital] the Relevant Regulator must take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have on a Service Provider, User and Prospective Users. If a Reference Tariff does include such a mechanism, the determination of the Rate of Return (under sections 8.30 and 8.31) and the economic life of the assets (under section 8.33) should take account of the resulting risk (and cost) to the Service Provider of a fall in the revenue received from sales of Services provided by means of the Covered Pipeline or part of the Covered Pipeline."

AGN is not aware of any material assets that have become redundant during the course of the First Access Arrangement Period. The administrative cost associated with the stranding of customer-specific assets, which are generally just the Meter and Service Pipe is unlikely to be of significant value where the benefit of removing these assets from the regulatory asset base outweigh the benefits to the community.

4.2.5 Opening value of the capital base as at January 2005

AGN has calculated the opening Capital Base as at 1 January 2005 in accordance with the methodology described above.

As at the time of preparation of this Access Arrangement Information actual data for 2004 was not available. AGN has used internal forecasts (including the $12m for FRC) to roll forward the asset base.

TABLE 4.3 - VALUE OF THE CAPITAL BASE FOR EACH YEAR OF THE SECOND ACCESS ARRANGEMENT PERIOD

(REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2005	2006	2007	2008	2009
High Pressure Mains	163.0	162.2	161.4	160.5	162.1
Medium Pressure Mains	200.5	200.7	200.7	201.4	201.4
Med / Low Pressure Mains	98.6	97.7	96.7	96.0	95.3
Low Pressure Mains	25.9	25.0	24.1	23.2	22.3
Secondary Gate Stations	1.8	1.7	1.6	1.5	1.4
Regulators	8.9	8.6	8.3	8.0	7.7
Meters & Service Pipes	117.1	123.1	127.4	134.6	141.2
Equip & Vehicles	3.2	3.5	3.4	3.9	2.5
Land & Buildings	7.4	7.4	7.4	7.4	7.4
FRC	9.6	7.2	4.8	2.4	0.0
Total	636.0	637.1	635.8	638.9	641.3

4.2.6 Assumptions on economic lives of assets for depreciation

For the purposes of determining Total Revenue the economic and average remaining lives of the assets forming the AGN GDS are set out in Table 4.4. These asset lives were used in determining Depreciation.

TABLE 4.4 - ECONOMIC LIVES OF ASSETS

Category of Asset	Economic life (Years)	Average Remaining life of Initial Capital Base (Years as at 30/6/04)
Mains:		
High pressure	120	101.5
Medium pressure	60	46.5
Medium low pressure	60	36.5
Low pressure	60	28.5
Secondary gate stations	40	20.5
Regulators	40	23.5
Meters:		
Residential	25	6
Commercial and industrial	25	6
Equipment and vehicles (including telemetry and monitoring systems)	10	1.5
FRC and Other IT Equipment	5	N/A
Buildings	40	19.5

4.2.7 Depreciation

Depreciation of the Capital Base is to be determined in accordance with the requirements of section 8.32 and 8.33 of the Code.

In accordance with these requirements of the Code, AGN has determined a Depreciation Schedule for each group of assets that form the AGN GDS. The Depreciation Schedule establishes the methodology for calculation of Depreciation to be used for the purpose of determining Reference Tariffs.

Depreciation for each group of assets that form the AGN GDS has been calculated using the straight-line method. Depreciation is set out in Table 4.5.

TABLE 4.5 - VALUE OF DEPRECIATION FOR THE SECOND ACCESS ARRANGEMENT PERIOD (REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2005	2006	2007	2008	2009
Mains:					
High pressure	1.6	1.6	1.6	1.6	1.6
Medium pressure	4.3	4.3	4.4	4.5	4.6
Medium low pressure	2.7	2.7	2.7	2.7	2.7
Low pressure	0.4	0.9	0.9	0.9	0.9
Secondary gate stations	0.0	0.1	0.1	0.1	0.1
Regulators	0.4	0.4	0.4	0.4	0.4
Meters and Service pipes	9.1	9.8	10.4	11.1	11.8
Equipment and vehicles (including telemetry and monitoring systems)	6.6	5.2	5.1	5.6	6.3
Buildings	0.1	0.1	0.1	0.1	0.1
Total	25.2	25.1	25.7	27.0	28.5

The return of capital forecasts in Table 4.5 have been prepared on the basis that:

- 50% of capital expenditure that occurs within a Year is included in that Year and the remaining 50% is included in the following Year (for the purposes of calculating the appropriate return of capital charge);
- the cost of each asset or group of assets forming part of the Covered Pipeline is recovered over the economic life of that asset or group of assets; and
- each asset or group of assets forms part of the Covered Pipeline required to deliver Services covered by the Reference Tariffs.

4.2.8 Capital Works and Capital Investment

Section 8.20 of the Code permits forecast capital expenditure on new facilities to be taken into account in determining Reference Tariffs, provided that expenditure is reasonably expected to pass the requirements in section 8.16 when the New Facilities Investment is forecast to occur.

AGN's forecast capital expenditure on new facilities taken into account in determining Reference Tariffs is summarised in Table 4.6.

TABLE 4.6 - FORECAST CAPITAL EXPENDITURE FOR THE SECOND ACCESS ARRANGEMENT PERIOD (REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2005	2006	2007	2008	2009
Mains:					
High pressure	0.6	0.8	0.8	0.7	3.2
Medium pressure	4.7	4.5	4.4	5.2	4.6
Medium low pressure	1.7	1.8	1.7	2.0	2.0
Low pressure	0.0	0.0	0.0	0.0	0.0
Regulators	0.1	0.1	0.1	0.1	0.1
Meters and Service pipes	16.9	16.6	15.5	19.2	19.2
Equipment and vehicles (including telemetry and monitoring systems)	3.5	3.1	2.6	3.7	2.5
Buildings	0.1	0.1	0.1	0.1	0.1
Total	27.6	27.0	25.2	31.0	31.7

4.2.8.1 Nature of planned new facilities investment

The planned New Facilities Investment shown in Table 4.6 mainly comprises:

- investment required to maintain the safety and integrity of the AGN GDS, to maintain Service levels, and to comply with regulatory requirements; and
- investment to extend the network to meet new User demand.

The main items of New Facilities Investment are shown in Table 4.7.

TABLE 4.7 - FORECAST CAPITAL EXPENDITURE FOR THE

SECOND ACCESS ARRANGEMENT PERIOD: BY TYPE OF INVESTMENT

(REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
Category of Expenditure	**2005**	**2006**	**2007**	**2008**	**2009**
User Initiated	20.1	18.6	18.4	20.4	20.4
Renewals	2.9	3.5	3.2	4.5	3.4
Demand	1.2	2.1	1.3	2.8	5.8
Other	3.4	2.8	2.3	3.3	2.1
Total	27.6	27.0	25.2	31.0	31.7

Detailed information relating to the forecast capital expenditure is set out below.

AGN's capital expenditure is broadly categorised as follows:

- **User Initiated Capital.** This is primarily capital required to connect new end use consumers on behalf of Users.
- **Renewals (Asset Replacement).** This involves the replacement of aged and obsolete assets, or replacement of assets where the present-value cost of maintaining existing assets exceeds the cost of replacement. This expenditure is primarily driven by asset condition, safety and maintainability.
- **Demand Capital.** This is capital to expand network capacity to cater for the additional load on existing assets from new connections, and also any increase in peak consumption per Delivery Point of existing consumers.
- **Other Capital.** This category includes miscellaneous capital items such as information technology equipment (including any on going FRC compliance), vehicles, office furniture etc.

4.2.8.2 Justification of new facilities investment

AGN has developed a detailed Asset Management Plan (AMP) which includes both the medium and high-pressure distribution systems for the period from 2004 to 2009. The AMP sets out the long term network development requirements from which the capital investments are derived. This long-term approach enables AGN to optimise its investment in network development by taking into account the best enhancement options resulting in maximum system integrity and minimum capital expenditure.

4.2.8.3 Demand and User-Initiated Capital Expenditure

Demand and User-initiated related capital expenditures are required to be undertaken, to ensure that the GDS has adequate Capacity to:

- meet peak load growth of existing consumers;
- meet peak load growth of new consumers;
- provide capacity upgrades for connection assets at Delivery Points;
- provide User-initiated capital expenditure including metering where applicable; and
- maintain system security, reliability of supply and safety standards.

Valuation of new assets is based on the forecast level of capital expenditure required to allow the Service Provider to meet forecast growth in demand for Reference Services. Augmentation of existing Services is essentially rolled-in to the Tariff, so that existing and Prospective Users will pay a common Tariff based on the overall cost of existing and new assets.

All work associated with demand related and User-initiated capital expenditure is contracted out. The unit rates used to compile cost estimates have been calculated from the average market rates paid for similar work. The unit rates have been benchmarked against comparable activities for UK Gas companies by GTL Consultants and found to be better than and/or broadly similar when adjusted for currency differences.

4.2.8.4 Renewals Capital Expenditure

The AMP sets out the long-term replacement plan for each major category of asset. Forecasts for renewals capital expenditure are based upon this Asset Replacement Strategy and an analysis of maintenance data for each asset class.

The maintenance plan forms a key element of the overall AMP and details what is necessary to maintain the assets at the required level of service and in a safe condition, while optimising life cycle costs for each category of asset. For mains and Services, leaks in the low-pressure network are the major source of maintenance costs. The low-pressure network has limited Capacity thus constraining the potential to accommodate redevelopment growth in an area without jeopardising system integrity.

The key area of asset renewal expenditure is distribution mains involving cast iron and steel mains in the low-pressure networks. The low-pressure network is limited in Capacity to support substantial growth. With approximately 1.5% of AGN’s new connections being on the low-pressure networks and multi-unit redevelopment prevalent in this area where the low-pressure network exists, AGN’s preferred method of mains replacement is to renew all low-pressure mains with medium pressure. This assists in achieving the long-term objective for development of the network, and eliminates ongoing maintenance problems associated with the low-pressure network.

In order to improve system reliability and security, extend asset life cycles and increase operational flexibility, AGN proposes a number of expenditure programs including:

- the installation of isolating valves on mains of 300mm or greater diameter to enable effective sectional isolation of network areas;
- the installation of cathodic protection and effective coating systems to mains currently not satisfactorily protected; and
- upgrading and or replacing sections of corroded mains to ensure ongoing operability and mitigate the risk of future failures due to further mains deterioration.

Other asset replacement expenditure will include the replacement of damaged and deteriorated high pressure blowdown and line valves that have been identified as part of scheduled maintenance programs.

A responsible approach to asset renewal is essential to maintain service standards and avoid future "bow wave" problems with large capital requirements. AGN's approach is therefore to replace assets at the end of their useful economic lives, taking into account safety issues and the need to maintain current service standards.

AGN believes that its integrated approach to renewals and demand capital programs ensures that capital expenditure is optimised. Further, AGN's approach to asset management is focussed on providing a safe, reliable network, operated and maintained on a cost effective basis, which meets the service, safety and environmental expectations of consumers, regulators and the community. The development of the 2004-2009 AMP is fundamental to successfully achieving this objective.

4.2.8.5 Other Capital (including FRC)

A significant amount of capital expenditure is required to support the business processes and network component of AGN's activities. During the First Access Arrangement Period, AGN prioritised its resources, within the constraints of the overall capital regulatory benchmarks, to deliver Services to meet its Distribution Licence obligations in respect of the level of demand growth experienced. As a result areas such as information technology were constrained.

Whilst this has delivered a low cost outcome in such areas in the First Access Arrangement Period, information technology expenditure in particular cannot continue to be deferred without unacceptable risk. In addition, the introduction of FRC in 2004 places increased obligations on AGN, increasing both the complexity and the performance requirements (availability & disaster recovery times) of AGN's systems.

Expenditure proposed for the Second Access Arrangement Period includes capital costs associated with:

- information technology infrastructure, such as PC / LAN network and printers;
- FRC;
- billing systems to enable distribution billing;
- asset management systems to assist in program management;
- external reporting requirements, such as statutory and regulatory accounts;

- internal management costing ledgers;
- cash payment and recording capability;
- motor vehicles and plant;
- miscellaneous field testing equipment; and
- office equipment.

Expenditure forecasts are based on the minimum requirements to support AGN's business and include costs associated with establishing and supporting FRC.

4.2.9 Return on the Capital Base

The Return on the assets that form the AGN GDS has been calculated, for each Year of the Access Arrangement, by applying a pre-Tax real Rate of Return (weighted average cost of capital, see Table 4.9) to an average of opening and closing asset values for the Year. The opening and closing asset values are expressed in (constant) 1 June 2003 dollar values.

The calculations are summarised in Table 4.8.

TABLE 4.8 - RETURN ON CAPITAL BASE FOR THE SECOND ACCESS ARRANGEMENT PERIOD

(REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
Category of Expenditure	**2005**	**2006**	**2007**	**2008**	**2009**
Asset values:					
Opening	634.4	636.0	637.1	635.8	638.9
Closing	636.0	637.1	635.8	638.9	641.3
Average	635.2	636.5	636.4	637.3	640.1
Return on average asset value	54.0	54.1	54.1	54.2	54.4

4.2.9.1 Rates of return - on equity and on debt

The forecast cost of providing all Services by means of the AGN GDS is determined, in accordance with the Cost of Service method, as the sum of a Return on the Capital Base, Depreciation, and the Non-Capital costs.

The Return on the Capital Base in each Year of the Access Arrangement is the product of the Rate of Return and an average asset value for that Year. AGN has used, as the Rate of Return to be applied to the average asset value, a weighted average of the pre-tax returns applicable to the equity and debt used to finance the assets, which form the AGN GDS.

AGN has obtained independent expert advice from KPMG in relation to estimating a Return on the Capital Base. KPMG's report, *The Weighted Average Cost of Capital for Gas Distribution*, has been provided to the Regulator as part of this Access Arrangement Information.

In section 2, AGN referred to legal and administrative decisions as to how the Code should be interpreted. Combined with commentary from the Productivity Commission, these decisions lead inexorably to the view that where there is a range of plausible values, the Code does not require that the lowest number be selected but rather somewhere within that range. KPMG's report has identified a range of values for each parameter of the cost of capital and AGN has selected values consistent with this principle. AGN has not selected the highest possible values, despite expert advice that such values would be within a reasonable range, but rather has elected for an overall figure which falls between the lowest and highest possible rates of return.

Given the highly capital intensive nature of the gas distribution sector, return on capital, which is a function of capital base and allowable Rate of Return, is one of the most significant revenue building blocks. Consistent with its analysis of the emerging regulatory environment outlined in section 2, AGN therefore believes the following principles should guide analysis of the cost of capital:

- **Function of the Regulator.** It has been clearly established that the function of the Regulator is not to determine a correct return but rather to decide whether what is being proposed by a Service Provider is consistent with the Code, and if it is, to approve it. Proposals can only be rejected if they are inconsistent with the Code. This has been affirmed in the specific cost of capital context by recent decisions of the Australian Competition Tribunal which found that "it is not the task of the Relevant Regulator to determine a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service. The task of the ACCC is to determine whether the proposed Access Arrangement in its treatment of Rate of Return is consistent with the provisions of s 8.30 and s 8.31 and that the rate determined falls within the range of rates commensurate with the prevailing market conditions and the relevant risk."[30]

- **Potential for Error.** The Regulator needs to recognise that regulation generally is an imprecise science, with high potential for regulatory error. The Productivity Commission found that this is particularly the case when assessing cost of capital: "Implementing the WACC/CAPM approach is not an exact science, given the numerous debatable assumptions involved."[31]

[30] *Application by GasNet Australia(Operations) Pty Ltd* [2003] ACompT 6, para. 42

[31] Productivity Commission, Gas Code Draft Report, p 234

- **Asymmetric Costs.** The costs of inevitable regulatory error do not behave symmetrically. The Productivity Commission, among others, has endorsed the view that the economic costs of under compensating Service Providers are likely to be greater than those of over compensation.[32] AGN believes that the long term interests of all parties, including Users, are best served by a cost of capital figure that sustains long term investment.

- **Standard of Workable Competition.** The Western Australian Supreme Court has found that the standard to be implemented when assessing an Access Arrangement is one of "workable competition". The outcome for cost of capital is that the lowest possible figure should not be selected but rather one consistent with the workable competition principle.

Based on these principles and the analysis outlined below, AGN is proposing a pre tax weighted average cost of capital of 8.5%.

The returns applicable to the equity and debt used to finance the assets which form the AGN GDS are based upon the following general formula:

Pre-tax real WACC = {(1+Pre-tax nominal WACC %) / (1+CPI)} -1[33]

Where:

Pre-tax nominal WACC % = K_e * 1 /{1-t*(1-γ)} * E/V + K_d*D/V

WACC is the weighted average cost of capital. E and D are, respectively, the market values of the equity and debt used to finance the assets, which form the AGN GDS, and V is the sum of E and D. K_e is the return applicable to equity, and K_d is the return applicable to debt. γ is the value attributed by investors to each dollar of franking credit, *t* and is the statutory corporate tax rate.

K_e can be estimated from capital market data using the Capital Asset Pricing Model:

$$K_e = R_f + \beta_e \times \mathrm{MRP}.$$

R_f is the risk free rate of return, β_e is the equity beta, and MRP is the equity market risk premium.

The parameter values applied in the determination of the WACC to be used as the Rate of Return for calculation of the Return on the Capital Base are summarised in Table 4.9.

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[32] Productivity Commission, Third Party Access Review, p 82

[33] This formula for the pre-tax real WACC is derived using the forward transformation approach. This entails firstly grossing up the post-tax nominal WACC by 1 minus the tax rate then to derive the pre-tax nominal WACC, and secondly, deflating the pre-tax nominal WACC by the inflation rate (derived via the Fisher equation) to obtain the pre-tax real WACC.

TABLE 4.9 - ESTIMATION OF THE RATE OF RETURN FOR THE SECOND ACCESS ARRANGEMENT PERIOD

Return Parameter		Value used to Determine Rate of Return in 2000	KPMG Recommendation
Risk free rate of return	R_f	6.27%	5.9%
Market risk premium	MRP	6.00%	7%
Equity beta	β_e	1.08	1.0
Debt margin	DM	1.20	1.4% -> 1.8%
Corporate tax rate	t	31.4%	30% (statutory rate)
Franking credit value	γ	0.50	0.3 -> 0.5
Debt to total assets ratio	D/V	60.0%	60%
Equity to total assets ratio	E/V	40.0%	40%
Pre-tax cost of debt	R_f + DM	7.5%	
Post-tax cost of debt	$K_d(1 - t(1 - \gamma))$	6.3%	
Post-tax cost of equity	$R_f + \beta_e \times MRP$	12.7%	
Expected inflation	π_e	2.78%	2.2%
Post-tax nominal WACC		8.9%	
Pre-tax nominal WACC		10.5%	
Pre-tax real WACC		7.5%	8.5%

4.2.9.2 Capital Structure - Debt/Equity Split Assumed

Section 8.31 of the Code provides guidance on how the returns applicable to the equity and debt used to finance the assets, which form the AGN GDS, are to be weighted in determining the Rate of Return:

> "In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice."

A de facto standard for the financing structure of going concerns in the regulated electricity and gas network industries is emerging in Australia. That standard is a financing structure comprising 60% debt and 40% equity. Accordingly, a financing structure comprising 60% debt and 40% equity was adopted for determination of the WACC used as the Rate of Return for calculation of the Return on the Capital Base. This financing structure is also a Fixed Principle for the purposes of sections 8.47 and 8.48 of the Code.

4.2.9.3 Equity Returns Assumed – Variables Used in Derivation

As noted in subsection 4.2.9.1, the Rate of Return on equity used in determining the WACC for the AGN GDS was calculated using the Capital Asset Pricing Model.

$$K_e = R_f + \beta_e \times MRP,$$

where R_f is a risk free rate of return, β_e is the equity beta, and MRP is the equity market risk premium.

The yield to maturity on Commonwealth Government 10 Year Treasury Bonds was used to estimate the risk free rate of return. That rate could be estimated using the yield on 10 Year Treasury Bonds at the time of WACC determination, or it could be estimated using an average of recent historic bond yields. An average of past bond yields - over the 20 trading days to 9 December 2003 - was used.

The nominal risk free rate of return used in calculating a return on equity for the purpose of determining the WACC was 5.9%.

Equity betas must be estimated from market data and, in consequence, are available only for companies listed on a stock exchange. For unlisted entities, like the business unit within AGN responsible for provision of Reference Services using the AGN GDS, equity betas must be estimated from the betas of listed companies engaged in comparable business activities. Beta estimation therefore involves a degree of subjectivity.

A beta of 1.00 was used in the calculation of the WACC, which is supported in more detail in the attached KPMG Report.

4.2.9.4 Debt Costs Assumed – Variables Used in Derivation

The rate of return on debt used in determining the WACC has been calculated as the sum of the risk free rate and an estimate of the margin applying to corporate debt. A debt margin of between 1.4 and 1.8 percentage points has been assumed. Using the assumed values for the risk free rate and the debt margin yields a resulting pre-tax cost of debt falling between a range of 7.3% to 7.7% used in the calculation of the WACC.

4.2.9.5 The Market Risk Premium

An equity market risk premium (MRP) of 7.0% was used in applying the Capital Asset Pricing Model in calculating the return on equity for the purpose of determining the WACC for the AGN GDS. This is dealt with in more detail in the attached KPMG Report.

The MRP has been subject to much uncertainty as it is a forward looking variable while all the most effective tests are based on historical averages. There are three ways of estimating the MRP:

- historical averages;
- economic models such as the Dividend Growth Model; and
- inter-country comparisons.

In a detailed review of the methods of estimating the MRP by Professor Stephen Gray in "Issues in Cost of Capital Estimation," 5 September 2003, an attachment to the Allgas submission to the Productivity Commission Inquiry into the National Gas Code, he argued that:

> "Theoretical economic models are based on potentially strong assumptions. A number of recent papers demonstrate that relaxing some of these assumptions solves the 'equity premium puzzle'. That is, the source of the puzzle lies in defects in the models rather than in sustained hysteria and irrational trading in equity markets causing the market risk premium to be greater than some simple economic models are able to explain. Moreover, there are many economic models from which to choose – how would a regulator justify the choice of a single model from within this large and growing, range of models? Choosing from among various theoretical economic models involves the same problems as using an asset-pricing model other than the CAPM – the choice of one of a number of competing models is subjective and it complicates matters as even more inputs and parameters must be estimated and debated."

Gray concluded that:

> "Historical estimates of the market risk premium are more precise than estimates based on the evident growth model, which is the primary theoretical model entertained by Australian regulators."

Finally, Gray concluded on the appropriate value of the MRP in light of the discussion of the various estimation techniques of the MRP by stating:

> "To adopt a market risk premium less than 6%-7% is to ignore the equilibrium outcome that reflects the collective wisdom of the market over the last 100 years."

In another submission to the Productivity Commission Inquiry into the National Gas Access Regime, NECG also analysed the MRP.[34] The NECG Paper also supports the use of 7% for the MRP:

> "Claiming that the MRP is less than 6% is inconsistent with the views of the ACCC's own advisor, Associate Professor Martin Lally, who supports a value of 6% for the MRP. Lally notes:
>
> > 'To summarise this review of evidence on the market risk premium in the Officer CAPM, the estimates are .07 from historical averaging of the Ibbotson type, .056 from historical averaging of the Siegel type, .07 from the Merton methodology, and .040-057 from the forward-looking approach. If a point estimate for the last approach is .048, then the average across these four approaches is .061. In addition various other methodologies have been alluded to, for which Australian results are not available but which have generated low values in the markets to which they have been employed. All of this suggests that the ACCC's currently employed estimate of .06 is reasonable, and no change is recommended.[35]'

[34] NECG response to ACCC supplementary submission No. 72 on International WACC decisions, March 2004,

[35] M. Lally, *The Cost of Capital under Dividend Imputation: A report for the ACCC,* June 2002, p34.

> The ACCC also ignores other evidence on the MRP. Historical data and the results of benchmarking the MRP in Australia in relation to other markets support a range of 6-8%. The historical estimates of Lally in the quote above are consistent with a value of 7% for the MRP. Although the ACCC has repeatedly stated an inclination to lowering the MRP from 6%, it has not presented a credible case for doing so. In our opinion, if the MRP is to be adjusted, the case is stronger for an increase to 7%."[36]

Both the Gray and NECG papers have been provided to the Regulator for consideration.

Professor Robert Bowman also argues that the MRP is much higher in Australia on the basis of inter-country comparisons. As quoted in the Gray paper Bowman argues that:

> "Australia has only recently become an open economy and that for much of the last 100 years equity and debt markets were subject to controls and intervention. For this reason, he argues that much of the historical data on the market risk premium is of limited use. His preferred approach is to base an estimate of the market risk premium on data from the United States, which has been an open economy for most of the period for which data is available. He suggests that an appropriate range for the U.S. market risk premium is 6% to 9% (p.6). Moreover, he suggests that Australia has a higher level of country risk that should result in a premium of 0.25% to 0.75% over the U.S. market risk premium. This yields a range of 6.25% to 9.75% for the Australian market risk premium."[37]

Gray also quotes a later paper by Bowman,

> "This paper is based primarily on conjecture and qualitative arguments rather than firm empirical evidence, especially with regard to the composition of the market index in the U.S. versus Australia. Nevertheless, the paper illustrates an alternative approach that suggests the market risk premium is greater than 6%. In particular, Bowman (2001) concludes:
>
>> 'It is suggested Australia use an approach based upon using the US MRP as a benchmark. The forward-looking US MRP is estimated to be 6% to 9% with a point estimate of 7.5%. There are a number of issues that can be considered to adjust the US benchmark. I believe that on balance they support an adjustment of at least 0.3%. In my opinion the appropriate MRP to use for Australia is 7.8%.'[38]"

Gray also quotes Ibbotoson Associates who also support a higher MRP in Australia:

> "The approach adopted by Ibbotson Associates (2001) is consistent with this conclusion. They suggest that the US market risk premium is 7.76% and that based on Australia's country credit rating, the expected return on the Australian market is 1.53% to 2.26% higher than for the U.S."[39]

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[36] NECG response to ACCC supplementary submission No. 72 on International WACC decisions March 2004, p.28

[37] Bowman, Robert, "Estimating the Market Risk Premium: The difficulty with Historical Evidence and an Alternative Approach," Working Paper, Department of Accounting and Finance, University of Auckland, 1999.

[38] Bowman, Robert, "Estimating Market Risk Premium," JASSA, 3, Spring, 2001 p.13.

[39] Ibbotson Associates, "International Cost of Capital Report 2001," valuation.ibbotson.com.

The need for a higher MRP and a return on capital is also supported by a major study of international rates of return by the NECG. In this paper NECG found that:

> "There is no evidence of excessively generous returns in the electricity distribution and transmission sectors, nor in the gas distribution sector – particularly against the U.S. Across all sectors where there are US compradors US decisions provide higher margins above the risk free rate than those in Australia and other countries".[40]

This review is important as it supports the Productivity Commission's proposals that higher returns in Australia should err on the side of giving higher returns to promote adequate investment in essential infrastructure.

The above evidence clearly supports an MRP of 7% as falling within the range of rates commensurate with the prevailing market conditions and the relevant risk profiles.

4.2.10 Return on Working Capital

An allowance for a return on the working capital employed in providing Reference Services has been included in the forecast total cost from which the Reference Tariffs have been determined. This is consistent with the approach adopted in the First Access Arrangement Period and consistent with the Code requirements to recover the efficient cost of providing Reference Services.

AGN has adopted a simplified approach based on the typical payment cycle on internal processes and receipt cycle detailed in Part C of the Access Arrangement. The two significant components of the working capital formula are based on 30 days applied to total revenue applicable to providing the Reference Services and 20 days applied to the payment of both capital and operating costs incurred to provide the Reference Services.

4.3 Information Regarding Operations and Maintenance

4.3.1 Non-Capital costs during the First Access Arrangement Period

AGN has spent more on operating and maintaining the AGN GDS in the First Access Arrangement Period than was projected in the initial Access Arrangement Information. Table 4.10 compares the regulatory forecasts and actual Non-Capital costs for the period 2000-2004.

[40] 'NECG, International Comparison of WACC Decisions', submission to the Productivity Commission Review of the Gas Access Regime, September 2003, Submission No. 56, p. 84'.

TABLE: 4.10 - BENCHMARK AND ACTUAL NON-CAPITAL COSTS

(REAL $ MILLION JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2000	**2001**	**2002**	**2003**	**2004**
Regulatory forecasts	41.2	39.2	38.6	38.2	38.4
Actual Cost	44.1	40.9	36.7	38.3	38.4

Significant restructuring costs were incurred in addition to the costs detailed in table 4.10 with a portion of these costs being incurred in 2000 and 2001. These restructuring costs have enabled AGN to achieve the level of efficiencies made. Without them, AGN's Non-Capital costs would likely have remained close to the actual 2000 – 2001 levels.

The outcome of this restructuring has seen an underlying cost base improvement of $5.7m from 2000 to 2004 (2004 forecast included $0.65m for FRC). This compares favourably with the regulatory benchmark improvement of $2.8m. This improvement in AGN's efficient cost base will be passed onto consumers in the Second Access Arrangement Period.

AGN considers that it is appropriate to infer that its actual operating expenditure is efficient because under the regulatory arrangements, distributors have a commercial incentive to minimise expenditure levels. In addition, it is important for AGN to demonstrate to all stakeholders that its actual expenditure is efficient.

AGN notes that it did not receive, nor will it receive any compensation for overspending against its benchmarks in the First Access Arrangement Period.

Notwithstanding the arguments presented above, AGN recognises that the Regulator and other stakeholders may require further assurances that the expenditure benchmarks proposed are consistent with the costs incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice. In section 4.3.11 below further evidence is provided, in the form of results obtained from independent benchmarking studies, which demonstrate that the company's proposed operating cost benchmarks for the Second Access Arrangement Period meet the requirements of clause 8.37 of the Code.

4.3.2 Non-Capital costs forecasts 2005-2009

In providing the Reference Services in each Year of the Access Arrangement, AGN's forecast of efficient Non-Capital costs is shown in Table 4.11.

TABLE 4.11 - NON-CAPITAL COSTS INCURRED IN PROVIDING THE REFERENCE SERVICES FOR THE SECOND ACCESS ARRANGEMENT PERIOD

(REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2005	**2006**	**2007**	**2008**	**2009**
Network	23.7	22.9	22.0	22.0	22.0
UAFG	3.0	3.0	3.0	3.0	3.0
Corporate	6.3	6.3	6.3	6.3	6.3
Marketing	1.3	1.3	1.3	1.3	1.3
Information Technology	4.9	4.9	4.9	4.9	4.9
Full Retail Contestability	1.3	1.3	1.3	1.3	1.3
Total	40.5	39.7	38.8	38.8	38.8

Section 8.37 of the Code requires that the Non-Capital costs used in Reference Tariff determination be only those costs that would be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable costs of delivering the Reference Services. AGN has, therefore, obtained an independent review of its Non-Capital costs to ensure that they satisfy the requirements of section 8.37. These results are summarised in section 4.3.12.

The costs of providing Services other than Reference Services are not included in the forecast in Non-Capital costs shown in Table 4.11.

4.3.3 Basis for Determining Operating Expenditure Benchmarks

AGN favours a regulatory approach to determining benchmarks that de-couples the company's own costs from its prices, on the basis that such arrangements:

- provide the strongest incentives for the pursuit of efficiency gains; and
- are more likely to provide outcomes that mimic those produced in real-life competitive markets.

Notwithstanding AGN's position on this issue, AGN recognises that the Code is biased towards a Cost of Service approach to regulation. This therefore limits the adoption of more effective alternative regulatory models favoured by AGN.

AGN has applied an approach in determining an estimate of efficient Non-Capital cost for the Second Access Arrangement Period that infers that the current level of expenditure is efficient. It has then applied an adjustment for changes in scope between the First and Second Access Arrangement Periods, to the extent that these changes drive changes in efficient Non-Capital costs.

TABLE 4.12 - SUMMARY OF COSTS ASSOCIATED WITH SCOPE CHANGES

(REAL $ MILLION AT JUNE 2003)

	2004	Changes in Scope	2005 Benchmarks
Network	22.3	1.4	23.7
UAFG	3.0		3.0
Corporate	6.3		6.3
Marketing	1.3		1.3
Information Technology	4.9		4.9
Full Retail Contestability	0.6	0.7	1.3
Total	38.4	2.1	40.5

4.3.4 Network

The two factors contributing to the scope change are:

- new regulations to be introduced by the State Government which require a land clearing permit to be obtained for activities such as gas Services, main extension, broken mains, new Services and leaks. Estimated activity per annum is 26,000 at a cost of $50 per permit; and
- the proposed introduction of a GSL Scheme described in section 3.10.

4.3.5 Full Retail Contestability

The forecast increase in 2005 is a result of a full Year of operation. FRC is scheduled to be implemented in May 2004 which is reflected in forecast operating costs.

4.3.6 Gas used in Operations

The AGN GDS has no compression thus, no Gas is used in operations. A small amount of Gas used during commissioning and maintenance is classed as operational losses and is included in Unaccounted for Gas (UAFG).

4.3.7 Unaccounted for Gas

UAFG is defined as the difference between the measurement of the quantity of Gas delivered into the AGN GDS in a given period, and the measurement of the quantity of Gas delivered from the AGN GDS during that period. This difference is the total effect of:

- errors in Gas measurement;
- operational losses resulting from leakage and third party damage to pipe work, and from the use of Gas to "blow down", purge and pressurise during the commissioning of new facilities, and after maintenance;
- system line pack variations;
- errors in the estimation of volumes of Gas delivered from the AGN GDS; and
- theft.

Measurement errors associated with the more than 480,000 Meters at Delivery Points, and operational losses, are the main contributors to UAFG and each accounts for approximately 50% of total UAFG.

The quantity of UAFG can fluctuate significantly over short periods of time, principally because of the random nature of Gas measurement errors. Over an extended period, a systematic loss should be observed.

The determination of the volume of UAFG for the Year cannot be completed until approximately six months after the end of each Year of the Access Arrangement, after all Meters have been read, and after all Meter readings have been verified and, if necessary, corrected. Between the Years 2000 and 2002 UAFG rates for the AGN GDS have fluctuated between 2.6 and 2.7%.

During the Second Access Arrangement Period, the systematic loss of the volume of Gas delivered from the network is projected to be in accordance with Table 4.13 below. The small increase from 2006 onwards reflects the planned Parmelia Pipeline interconnection of the South Metropolitan Sub-Network and the forecast increase in the amount of Parmelia Gas entering both the North and South Metropolitan Sub-Networks. One consequence of having blended gas flowing into a Sub-network is that there will be the potential for greater variation in heating value which in turn is used to determine energy consumed. The Declared Heating Value regulations will introduce a monitoring regime to ensure that the flow weighted average of the blended Gas falls within an acceptable range. The range of +/- 1 megajoule introduces additional uncertainty in the calculation of UAFG in the order of +/-0.1% of network inflow.

TABLE 4.13

UAFG PERCENTAGE OF VOLUME OF GAS DELIVERED

	2005	2006	2007	2008	2009
Total	2.7%	2.8%	2.8%	2.8%	2.8%

Although in the past, AGN has been responsible for calculating UAFG, this responsibility will transfer to the Retail Market Company Limited (REMCo) under the Retail Market Scheme for the majority of Sub-networks.

On a daily basis AGN, based on its knowledge of Gate Point Inflows and interval metered consumption, will estimate UAFG for the previous day for each Sub-network. This estimate will be validated by REMCo prior to it being allocated to AGN's nominated UAFG supplier.

REMCo will perform a daily reconciliation of changes in UAFG for each Sub-network of the AGN GDS, largely as a result of actual basic Meter readings replacing estimated interval Meter readings and also due to revised basic and interval Meter readings. REMCo will calculate such revisions for up to 425 days in the past and will apply the resulting reconciliation amounts to the present day UAFG supplier. This reconciliation process is likely to result in substantial variations in the daily amounts of UAFG calculated.

Users are not required to make any allowance for UAFG. All of the UAFG is purchased separately by AGN. Forecasted benchmarks of UAFG purchase costs are included in the Non-Capital costs for recovery through the Reference Tariffs.

4.3.8 Fixed versus variable costs

The Non-Capital costs are fixed costs; they do not vary materially with the throughput of the AGN GDS.

4.3.9 Cost allocation

The allocation of costs between categories of asset and Services is described in section 5.

4.3.10 Summary of Composition of Total Revenue

Table 4.14 below provides a summary of the composition of the Total Revenue for each Year of the Access Arrangement Period commencing in January 2005.

TABLE 4.14: COMPOSITION OF TOTAL REVENUE FOR THE SECOND ACCESS ARRANGEMENT PERIOD (REAL $ MILLION AT JUNE 2003)

	YEAR ENDING 31 DECEMBER				
	2005	**2006**	**2007**	**2008**	**2009**
Non-Capital Costs	40.5	39.7	38.8	38.7	38.7
Return on Capital	54.0	54.1	54.1	54.2	54.4
Depreciation	25.2	25.1	25.7	27.0	28.5
Efficiency carry-over	0.0	0.0	0.0	0.0	0.0
Return on Working Capital	1.0	1.0	1.0	1.0	1.0
Total Revenue	**120.7**	**119.9**	**119.6**	**121.0**	**122.6**

In developing its revision to the Access Arrangement, AGN has been conscious of the need to ensure that any price change does not deliver a price shock to either Users, consumers or AGN.

As is demonstrated by the evidence presented in sections 4.2 and 4.3 of this Access Arrangement Information, AGN's present costs and prices already fully reflect those of an efficient business. At the time of the First Access Arrangement Review in 2000, the Regulator removed substantial Non-Capital Costs from the business, reducing the Non-Capital benchmark from $41.2m in 2000 to $38.4m in 2004.

In considering its future revenue needs, AGN has identified scope changes for the Second Access Arrangement Period and an increase in its capital base as a result of efficient capital spend in the First Access Arrangement Period. The result, when added to the existing efficient cost base results in a price increase (X factor) of 2.18% for each of the five Years in the Second Access Arrangement. This calculation includes the expected cost of regulation. If the proposed regulatory cost recovery mechanism is accepted, X will become 1.97%.

4.3.11 External Assessment of AGN's efficiency

In the preparation of this Access Arrangement AGN has engaged consultants to review its unit costs and overall operating forecasts. AGN engaged PA Consulting to review the company's budgeted O&M, to assess whether these would exceed the costs that would "be incurred by a prudent Service Provider, acting efficiently" (in accordance with clause 8.37 of the Access Code). PA Consulting concluded that:

> "the forecast Non-Capital costs proposed by AGN meet the requirements of section 8.37 of the Code."

In addition to PA Consulting, GTL International was also engaged to review the unit costs of 19 field operations encompassing both capital and operating cost categories. This was to ensure that the unit costs used in these forecasts (both capital and operating) have been assessed as comparable and/or more competitive than UK benchmarks.

Table 4.15 below summarises the Key Performance Indicators (KPI) computed by PA Consulting.

TABLE 4.15: UNIT PERFORMANCE MEASURES FOR A SAMPLE OF FIVE AUSTRALIAN GAS DISTRIBUTORS

KPI's	AGN	Multinet	Envestra (Vic)	TXU	Envestra (Qld)
$M/100 Km Main	3424	4524	4843	5170	5670
$/O & M Costs per Customer	76.6	63.0	78.3	84.4	164.4
$/GJ	1.32	0.86	1.11	1.38	2.22
Customers/Main (km)	44.5	71.8	61.8	61.2	34.5

The two independent unit cost analyses both indicate that AGN is efficient compared to its domestic peers.

Conclusions

In summary:

- Non-Capital Cost benchmarks submitted in this Access Arrangement Information were assessed by PA Consulting as those of a superior cost performer in its use of Non-Capital Costs inputs assessed against other Australian distributors;
- unit costs underpinning these forecasts (both capital and operating) have been assessed by GTL International as comparable to and/or more competitive than UK benchmarks;
- AGN has achieved significant efficiency gains in the First Access Arrangement Period; and
- different benchmarking methodologies have consistently assessed AGN as being highly efficient, based on forecast data contained in this Access Arrangement Information.

Taking all of these considerations into account, AGN considers that the company's actual cost performance in the First Access Arrangements Period, adjusted for scope changes, provides a sound indication of the efficient level of Non-Capital Costs for AGN over the Second Access Arrangement Period. It also considers that this methodology is consistent with the requirements of the Code and as such the cost estimates provided should be approved by the Regulator as being efficient and prudent.

5 Cost Allocation and Variation

5.1 Cost Allocation

The Reference Tariffs applying in 2005 (the first Year of the Second Access Arrangement Period) have been determined based on detailed cost of supply modelling described in the 2000 Access Arrangement Information. The only significant amendment was required to comply with the introduction of FRC and the subsequent introduction of Reference Tariff A2 (and a consequential amendment to Reference Tariff B1).

Since the initial Reference Tariffs were set, the price control formula in the First Access Arrangement Period has restricted the Tariff Component relativities from being altered. No new Tariffs or Tariff Components were introduced over that period, and the nature of AGN's distribution business, and the basis of allocating its underlying costs have not changed materially since 2000, with the exception of FRC and growth in new residential connections. To the extent that these result in an increase to the cost base, these have been appropriately allocated to the Reference Services. The costs and revenue relativities remain consistent with those determined by the cost of supply model applied in 2000.

AGN's view is that the Reference Tariffs for the first Year of the Second Access Arrangement Period, when "rolled forward" from the final Year of the First Access Arrangement Period comply with the relevant provisions of the Code, and should therefore be approved by the Regulator.

As mentioned previously, the only amendment to the Reference Tariff structure occurs at the beginning of the Second Access Arrangement Period due to the introduction of FRC. Reference Tariff B1 has been separated into the new Reference Tariff A2 and an amended Reference Tariff B1. Refer to sections 3.4.2 and 3.4.3 for more details regarding these revised Reference Tariffs.

The new Reference Tariffs have been structured to reflect the costs associated with the provision of the Reference Services A2 and B1. The combined cost of providing the new Reference Service A2 and amended Reference Service B1 do not alter from the cost of providing Reference Service B1 in 2004 with the exception of the forecast of total costs and volumes during the Second Access Arrangement Period.

5.2 Form of Price control

In this Access Arrangement revision, AGN has proposed a tariff basket form of price control as an appropriate and efficient form of price control, consistent with the requirements of the Code. Under a tariff basket, the limit on allowed price increases is expressed in terms of a ratio of "notional revenues", taking into account all of the components of a Service Provider's Tariffs:

- the first "notional revenue" is the revenue implied by the quantities of each Tariff Component sold in the previous Year and the Service Provider's current Tariffs. This becomes the denominator in the price control formula; and
- the second notional revenue is the revenue that would result if the same Quantity was sold at the Service Provider's proposed (new) prices. This becomes the numerator in the price control formula.

This cap is (CPI) x (1-X) x (1+R)

Where:

CPI is as defined in Schedule 2 of Part A of the Access Arrangement

X is the X factor

R is the regulatory cost recovery factor as outlined in clause 8 of Part B of the Access Arrangement.

AGN has adopted a tariff basket price-cap approach to Reference Tariff variation on the grounds of economic efficiency and compliance with the Code.

Section 8 of the Code sets out the principles to be followed in Tariff variation and section 8.3 provides that as long as a variation policy is consistent with the objectives contained in section 8.1, then this falls within "the discretion of the Service Provider." AGN believes a tariff basket approach is consistent with section 8.1 and notes that such an approach has been both advocated by regulators and applied in other jurisdictions.

There are also strong efficiency arguments for a tariff basket approach which are directly applicable to the section 8.1 criteria:

- **Risk.** AGN faces significant risk in forecasting volumes, with issues such as weather and competition from other energy sources meaning that outcomes may vary considerably from those forecast. Given that revenues are a function of volume and Tariffs, this creates a commercial risk. The tariff basket approach allows this risk to be managed in the most efficient way, by allowing revenues to shift between Reference Services, subject to an overall cap to ensure that AGN is not earning more than its allowable revenue as a result.

- **Variations in Costs.** The cost of providing Reference Services may also vary within an access period. The tariff basket approach allows for Tariff variation to meet these cost changes so that the cost of providing Services continues to track the revenues from those Services. A scenario where costs and revenues diverge is a recipe for inefficiency and runs counter to the principles in section 8.1.

- **Efficient Behaviour by Service Provider.** A tariff basket approach promotes efficient behaviour by AGN in that it does not encourage restrictions or increases to output when it is not efficient to do so.

- **Reduced Cost of Tariff Variation.** It has been suggested that an alternative to a tariff basket approach is that a Service Provider can trigger a revision at any time and that therefore Tariff variation can be dealt with in this way should they be necessary. However, this ignores the very significant costs involved in a reset – costs which ultimately are borne by Users. AGN believes the tariff basket approach provides a much more cost-effective approach to Tariff variation.

5.3 Variation of Reference Tariffs

The Reference Tariff Principles of section 8 of the Code permit the setting of Reference Tariffs for the first Year of the Access Arrangement, and adjustment of those Tariffs in subsequent Years. The approach to future Tariff adjustment is referred to as the form of regulation. The form of regulation may be:

- Tariff adjustment in accordance with a pre-determined price path;
- Tariff adjustment on the basis of actual outcomes (such as sales volumes and actual cost) in subsequent Years; or
- Tariff adjustment in accordance with a variation or combination of these two approaches.

The Reference Tariff Policy set out in Part B of the Access Arrangement provides for Tariff adjustment in accordance with a pre-determined price path combined with an adjustment to reflect the actual costs of regulation imposed upon AGN.

The method by which the Reference Tariffs are to be adjusted in each Year of the Access Arrangement after the first is set out in Part B, of the Access Arrangement.

AGN has adopted a tariff basket price-cap approach to the variation of the Reference Tariffs during the Second Access Arrangement Period. Under the price-cap, AGN may vary any Tariff or Tariff Component, or add or remove a Tariff Component (and thereby vary the corresponding Reference Tariff) for each Year so that the change to the value of the tariff basket does not exceed CPI x (1-X) x (1+R), where CPI is the Year on Year increase in the Consumer Price Index and R is the regulatory cost factor reflecting the actual regulatory costs imposed on AGN (as defined in Part B of the Access Arrangement).

X has the effect of smoothing the price variations evenly over the Second Access Arrangement Period.

AGN will give the Regulator a Variation Report consistent with section 8.3 of the Code.

5.4 Prudent Discounts

Clause 8.43 of the Code provides for prudent discounts to be applied, with the approval of the Regulator, to Reference Tariffs in appropriate circumstances. Under the Code, a User subject to a prudent discount must be in circumstances where paying the Reference Tariff would result in them not using the Service. As a result the Reference Tariff for other Users would be higher than if calculated on the basis of a prudent discount approach.

The Code allows the cost of discounts to be recovered from other Users on the basis that it provides a benefit to them by spreading system costs across a wider Tariff base, even taking into account the discounts offered.

Consistent with the Code, a discount to the relevant Reference Tariff is offered where:

- there has been (or will be) a reasonable expectation that:
  - the User can obtain haulage Service from a bypass pipeline at a Tariff lower than the relevant Reference Tariff; or
  - without the discount, the consumer supplied by the User would cease to use Gas delivered from the AGN GDS; and
- continued delivery of Gas from the AGN GDS to the consumer, with the User paying a discounted Reference Tariff, would result in Reference Tariffs which were lower than they would have been if the User were to have obtained haulage Service from a bypass pipeline, or if the consumer supplied by the User had ceased to use Gas delivered from the AGN GDS.

That part of the Total Revenue which is not recovered from those Users of Reference Service A1, Reference Service A2 and Reference Service B1, paying a discount to the relevant Reference Tariff, is recovered from the remaining Users.

While the Access Arrangement for the First Access Arrangement Period has no stated provision for prudent discounts and thus no mechanism to recover the foregone revenue from discounting, AGN implemented a discount regime during that period based on a rigorous assessment of applications received to ensure that both criteria under the Code are met. As AGN has under recovered from those Users receiving discounts, there has been an extremely powerful incentive to restrict discounts only to those Users who would otherwise not use the system at all. For the Second Access Arrangement Period it is anticipated that those Users who received discounts in the First Access Arrangement Period, and continue to be in the same situation in the Second Access Arrangement Period, will continue to receive prudent discounts.

5.5 Fixed Principles

Section 8.47 of the Code allows a Service Provider to submit, as part of its Reference Tariff Policy, certain Fixed Principles. Fixed Principles are included in an Access Arrangement to provide certainty to a Service Provider that certain matters will not be subject to review at the conclusion of a specific Access Arrangement Period, instead continuing for a defined period, the Fixed Period. There is no restriction on the subject matter of Fixed Principles, other than that they are "elements of the Reference Tariff Policy" and "may include any structural element". In practice, Fixed Principles relate to those elements of the Access Arrangement that the Service Provider is particularly concerned should not be automatically reviewed as part of the revision process and where longer term stability is appropriate. Fixed Principles cannot be changed when the Service Provider submits reviews to an Access Arrangement, without the agreement of the Service Provider.

The Access Arrangement for the First Access Arrangement Period contains the following Fixed Principles, each of which applies for a Fixed Period of 10 Years commencing 1 January 2000, unless amended as provided for above.

(a) the method of calculation of the Total Revenue;

(b) the method of forecasting New Facilities Investment;

(c) the financing structure assumed for the purposes of determining the Rate of Return in accordance with section 8.30 of the Code;

(d) the Depreciation Schedule;

(e) the method of allocating revenue between Services; and

(f) the form of regulation.

AGN proposes that these Fixed Principles, which currently operate for ten Years from January 2000, should be amended to run for ten Years commencing 1 January 2005. The form of regulation, which is Fixed Principle (f), is subject to revision as AGN is recommending a tariff basket price cap approach in place of the current price cap. This tariff basket approach incorporates a regulatory cost pass through mechanism to allow the actual costs of regulation to be recovered. Such a mechanism is consistent with the Code and used in other jurisdictions.

In Part B, of the Access Arrangement, AGN has proposed two additional Fixed Principles, namely:

- the inclusion of FRC costs in non-capital costs as described in Part B of the Access Arrangement; and
- the Incentive Mechanism described in Part B of the Access Arrangement

Both Fixed Principles are proposed to apply for a Fixed Period of 10 Years. Set out below is the rationale in support of these additional Fixed Principles.

5.5.1 FRC Cost Recovery

The principle of FRC cost recovery is sought as a Fixed Principle as AGN has, and will be expending significant amounts of money in complying with its obligations under the Retail Market Scheme as a result of the introduction of FRC. In doing so it has consistently been concerned that it can recover this expenditure and, to the extent possible under the Code, has sought the Regulator's approval of both the costs and cost recovery before proceeding. To date the Regulator has taken the view that these costs can be recovered and AGN believes this should continue into the longer term.

5.5.2 Incentive Mechanism

As part of its revisions, AGN is proposing a multi period Incentive Mechanism which would operate for ten Years. As such, AGN believes it is appropriate that there should be certainty as to the Incentive Mechanism over the anticipated period of operation and that there should therefore be a Fixed Principle preventing its amendment half way through the incentive period.

6 Information Regarding System Capability and Volume Assumptions

6.1 Description of System Capabilities

The AGN GDS is not a contiguous system of Gas distribution pipes and associated facilities, but comprises a number of discrete segments or Sub-networks. At the time of submission of this Access Arrangement Information to the Regulator, the AGN GDS comprised approximately 11,320 kilometres of Gas distribution pipelines and associated facilities located in the following areas of Western Australia:

- Geraldton;
- Eneabba;
- Muchea;
- the Perth metropolitan area (including Ellenbrook, Rockingham and Mandurah);
- Pinjarra;
- Harvey;
- Kemerton;
- Bunbury;
- Capel; and
- Busselton.

Each of these Sub-networks has been constructed using similar methods and materials, and each operates under a similar pressure regime. Each is supplied with Gas from one or more Receipt Points immediately downstream of Meter stations on the Dampier to Bunbury Natural Gas Pipeline and the Parmelia Pipeline. These Meter stations and Receipt Points are at the following locations:

- Nangetty Road (Geraldton);
- Eneabba;
- Muchea;
- Della Road (Bullsbrook);
- Ellenbrook;
- Harrow Street, (West Swan);
- Caversham;
- Welshpool;

- Forrestdale;
- Russell Road, (Wattleup);
- Barter Road;
- Rockingham;
- Oakley Road (Pinjarra);
- Harvey;
- Kemerton; and
- Clifton Road (Bunswick).

Gas delivered into the AGN GDS is delivered into the High Pressure System. The High Pressure System comprises all pipelines in the AGN GDS operating at a nominal pressure greater than or equal to 300 kPa. The operating pressure of the various GDS are listed in Table 6.1

TABLE 6.1: AGN GDS OPERATING PRESSURES

Network Segment	Maximum Allowable Operating Pressure (kPa)	Nominal Operating Pressure (kPa)	Minimum Operating Pressure (kPa)
Geraldton lateral	6,900	3,800	2,400
Narngulu high pressure	1,900	1,000	700
Geraldton town high pressure	1,900	800	700
Geraldton town medium pressure	60	35	15
Eneabba lateral	1,900	1,500	700
Muchea lateral	1,900	1,200	700
Perth metropolitan:			
Della Road lateral	6,900	3,000	2,200
Harrow Street lateral	6,900	3,000	2,500
East Perth lateral	5,300	4,000	2,400
Barter Road high pressure	1,900	1,800	700
Class 150 high pressure	1,900	1,800	700

Network Segment	Maximum Allowable Operating Pressure (kPa)	Nominal Operating Pressure (kPa)	Minimum Operating Pressure (kPa)
Rockingham HP (including Mandurah)	1,900	1,800	700
Fremantle high pressure	550	550	350
Perth city block	200	200	160
Neerabup polyethylene	200	80	60
Ellenbrook polyethylene	200	180	60
Medium pressure	60	40	15
Medium low pressure	7	5.5	2
Low pressure	3	2	1.25
Pinjarra high pressure	700	600	350
Pinjarra medium pressure	60	30	15
Harvey high pressure	1,900	1,500	700
Harvey medium pressure	60	40	15
Kemerton high pressure	1,900	1,000	900
Bunbury high pressure steel	1,900	1,800	700
Bunbury medium pressure	60	40	15
Capel to Busselton polyethylene	500	450	350
Busselton polyethylene	200	100	60

A number of secondary gate stations, at which pressure is reduced, are an integral part of the High Pressure System. These Pressure Reducing Stations are located:

- in the Geraldton area, at Narngulu and Bootenal, and in the town of Geraldton;
- in the Perth metropolitan area, at Wanneroo (Neaves Road), South Caversham, Viveash, Ballajura, Bayswater and East Perth; and
- in the Bunbury-Busselton area, at Capel.

Gas flows from the High Pressure System into the Medium Pressure/Low Pressure System through approximately 143 high pressure regulator sets. These regulator sets reduce pressure to nominal pressures less than 300 kPa. The Medium Pressure/Low Pressure System comprises these high pressure regulator sets together with those pipelines that operate at nominal pressures less than 300 kPa.

The nominal operating pressures of the pipelines that comprise the Medium Pressure/Low Pressure System are listed in Table 6.1. The nominal operating pressure of a network segment is the pressure (measured at the start of the segment) at which the segment is normally operated. The nominal operating pressure may be less than the segment's maximum allowable operating pressure for a number of reasons including the provision of operating margins for control equipment gas flow stop processes for breaks response and load management.

The maximum allowable operating pressure for a network segment shown in Table 6.1 is the maximum pressure at which that network segment may be operated without any modification.

Pipelines comprising the Medium Pressure/Low Pressure System are constructed predominantly from polyvinyl chloride pipe, although some sections of main have been constructed using polyethylene, steel, galvanised iron or cast iron pipe.

Approximately 295 medium pressure Regulator sets reduce pressure within the Medium Pressure/Low Pressure System from medium to medium low and low pressures.

Gas is delivered from the mains of both the High Pressure System and the Medium Pressure/Low Pressure System through Service Pipes, valves, regulators, and Meters, all of which are usually located immediately upstream of Receipt Points. These facilities are integral parts of the High Pressure and Medium Pressure/Low Pressure Systems, as are the Meters and data logging facilities at secondary gate stations, regulator sets and Receipt Point metering. These data logging facilities record Gas flows, temperatures and pressures for the monitoring of system operation and performance, and for the billing of Users.

The Capacity of the AGN GDS and its potential, as currently configured, to deliver a particular Service between a Receipt Point and a Delivery Point at a point in time, is determined by the minimum pressures at which the various segments of the network operate. These minimum operating pressures are shown in Table 6.1. They are the minimum pressures, which must be sustained in the various segments of the network so as to provide a safe Gas supply and meet User delivery requirements under peak load conditions.

If the delivery requirements of a Prospective User were expected to cause the pressure in a network segment to fall below the minimum operating pressure of that segment, system enhancement would be required before a Service could be provided to that Prospective User.

6.2 Average Daily and Peak Demands

Table 6.2 shows the current average and peak daily demands for the AGN GDS, and current maximum hourly demand.

TABLE 6.2: SYSTEM AVERAGE AND MAXIMUM QUANTITIES 2003

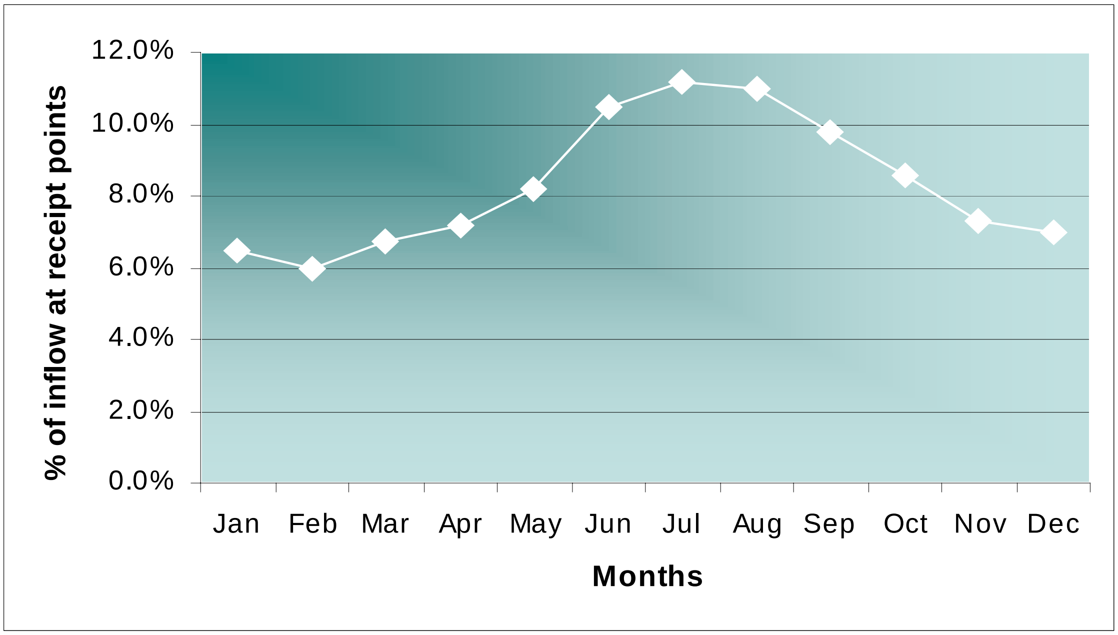
	TJ
Average daily quantity	**82.7**
Maximum daily quantity	**129.7**
Maximum hourly quantity	**8.9**

The load profile of the AGN GDS is shown in Table 6.3 and Figure 6.1.

TABLE 6.3: TYPICAL SYSTEM LOAD PROFILE BY MONTH

Month	Total Gas inflow at Receipt Points (%)
January	6.5%
February	6.0%
March	6.7%
April	7.2%
May	8.2%
June	10.5%
July	11.2%
August	11.0%
September	9.8%
October	8.6%
November	7.3%
December	7.0%
Total	100.0%

Figure 6.1 System Load Profile by Month



6.3 Annual Volume

AGN engaged the National Institute of Economics and Industry research (NIEIR) to assist in the preparation of volume forecasts. The model used by NIEIR was developed within a regional economic model of the Western Australian economy.

Temperature is an important factor affecting consumption. Data collection from the Australian Bureau of Meteorology from various Perth based weather stations indicates a strong trend towards warming weather. This has been factored into the "Heating Degree Days" underpinning the volume forecasts.

In addition, average consumption by Small Use Customers for residential purposes is expected to be negatively impacted by two key items.

- the replacement of gas hot water systems by solar hot water systems supported by State and Federal rebate schemes; and
- the extensive use of reverse cycle air conditioners replacing traditional gas heating loads.

Early evidence suggests that these impacts will have the potential to reduce average usage, below that is included in Table 6.4 and 6.5 for Small Use Customers. This is further reason why the introduction of the Tariff basket is required to protect AGN's ongoing investment.

TABLE 6.4: FORECAST VOLUMES BY SERVICE

	Year ending 31 December				
Service	2005 TJ	2006 TJ	2007 TJ	2008 TJ	2009 TJ
Reference Service A1	14,637	15,346	15,968	15,609	15,636
Reference Service A2	2,050	2,117	2,161	2,185	2,251
Reference Service B1	1,804	1,862	1,901	1,923	1,982
Reference Service B2	1,044	1,079	1,109	1,128	1,161
Reference Service B3	9,978	10,253	10,539	10,763	10,959
Total - by Service	29,513	30,658	31,678	31,608	32,040

6.4 Delivery Point Numbers

The estimated numbers of Delivery Points at which Gas is delivered to Users are shown in Table 6.5.

TABLE 6.5: FORECAST DELIVERY POINTS 2005 - 2009

Service	2005	2006	2007	2008	2009
Reference Service A1	58	58	58	58	58
Reference Service A2	83	83	83	83	83
Reference Service B1	1,076	1,097	1,109	1,122	1,147
Reference Service B2	4,641	4,748	4,842	4,898	5,001
Reference Service B3	486,850	501,787	519,069	535,042	548,841
Total Delivery Points	492,708	507,773	525,161	541,203	555,130

7 Information Regarding Key Performance Indicators

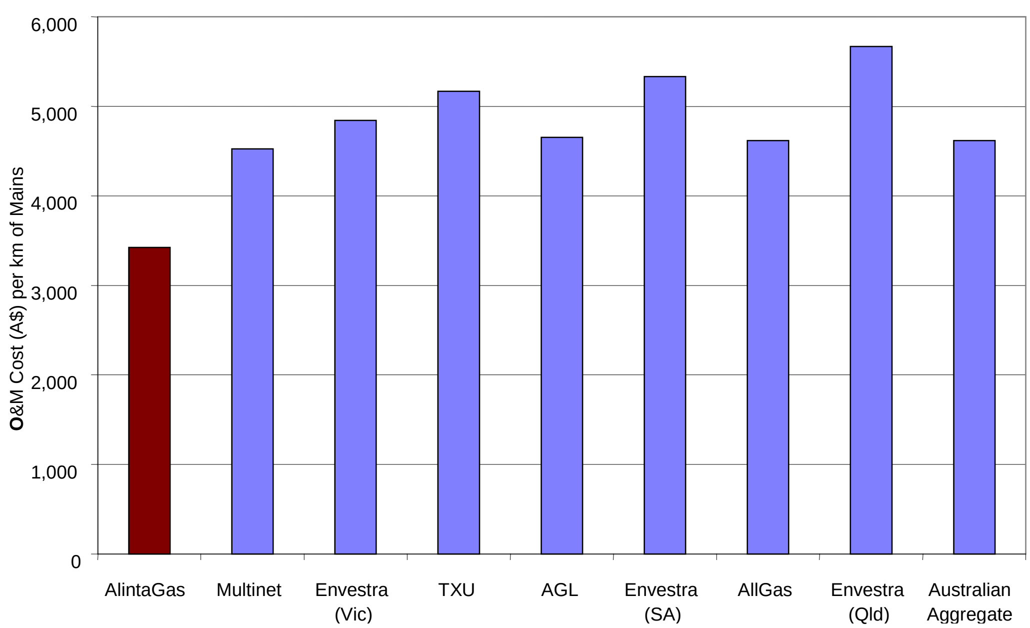
A number of key performance indicators have been used as benchmarks against which the forecast of capital expenditure, and the Non-Capital costs, used in determining the Reference Tariffs have been assessed for reasonableness. They are presented in the following subsections of this section.

These key performance indicators were compiled by the PA Consulting Group as part of its independent assessment review of Non-Capital costs. PA's general conclusion is that AGN "delivers comparable customer service standards, and is generally in the top or second quartile of cost efficiency."[41]

7.1 Operating and Maintenance Cost per Kilometre of Main

AGN's operating and maintenance cost per kilometre of main compares favourably against that of other Australian Gas distribution businesses. The comparison is presented graphically in Figure 7.1. Operating and maintenance cost per kilometre of main is the most important of the available measures for assessing the reasonableness of Non-Capital costs because network size is a fundamental cost driver.

Figure 7.1: Operating and Maintenance Cost per Kilometre of Main

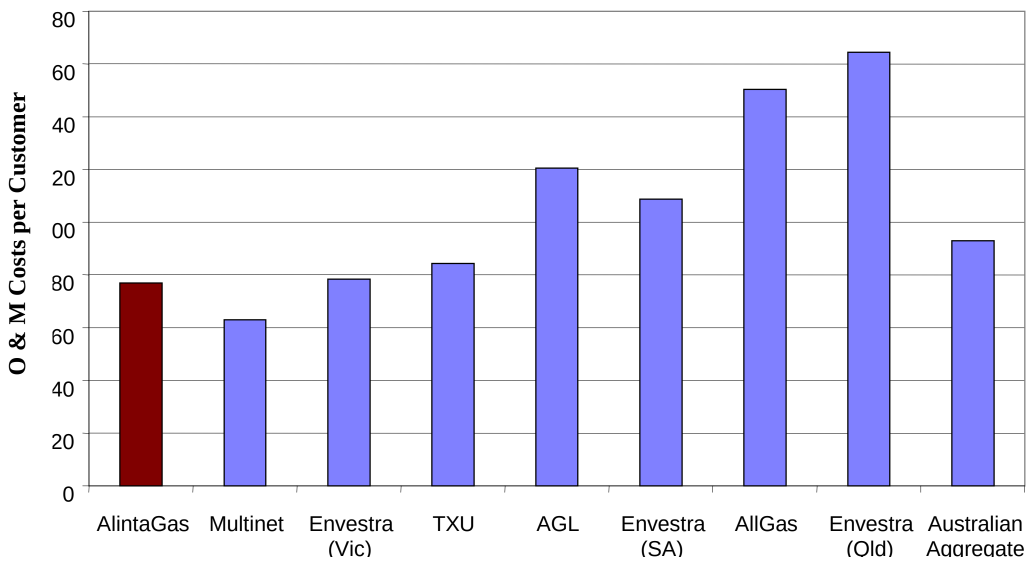


[41] PA Consulting Group, March 2004, *AlintaGas Networks Review of Operating And Maintenance Costs*, p.i

7.2 Operating and Maintenance Cost per Customer

Operating and maintenance cost per customer ranks second lowest in the Australian comparisons and well below the national average. This is shown in Figure 7.2.

Figure 7.2: Operating and Maintenance Cost per Customer

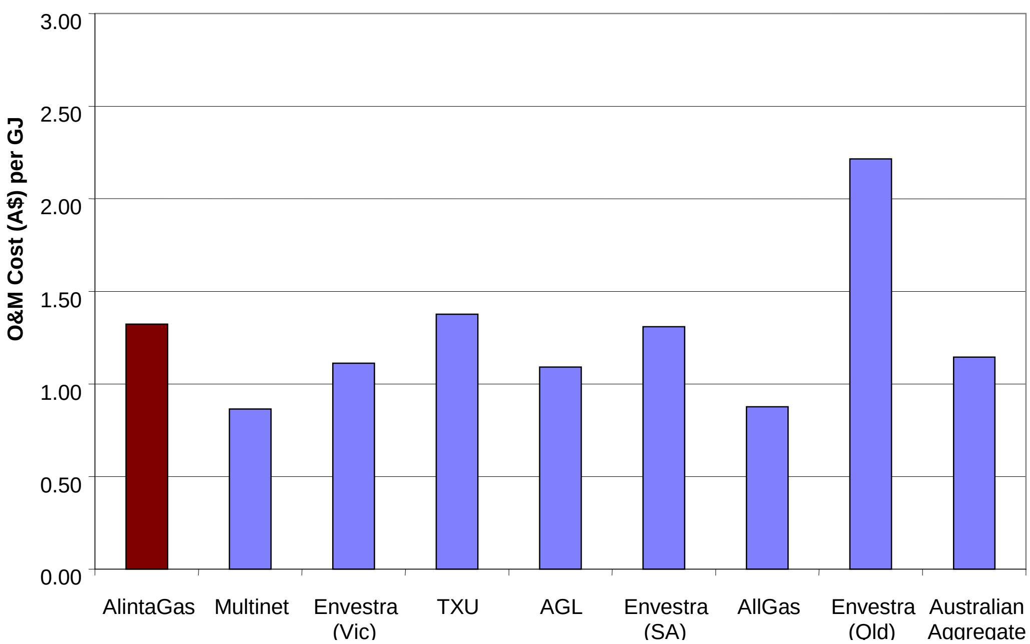


Only one Victorian Gas distributor is superior in terms of operating and maintenance cost per Delivery Point. This result is particularly good given Melbourne has a higher density of Delivery Points (the number of Delivery Points per kilometre of main is higher in Victoria than elsewhere in Australia), and a higher incidence of winter heating, than Perth. Western Australia's mild winters, hot summers and low Delivery Point density constrain the demand for reticulated natural Gas and limit AGN's performance on this measure.

7.3 Operating and Maintenance Costs per GJ Delivered

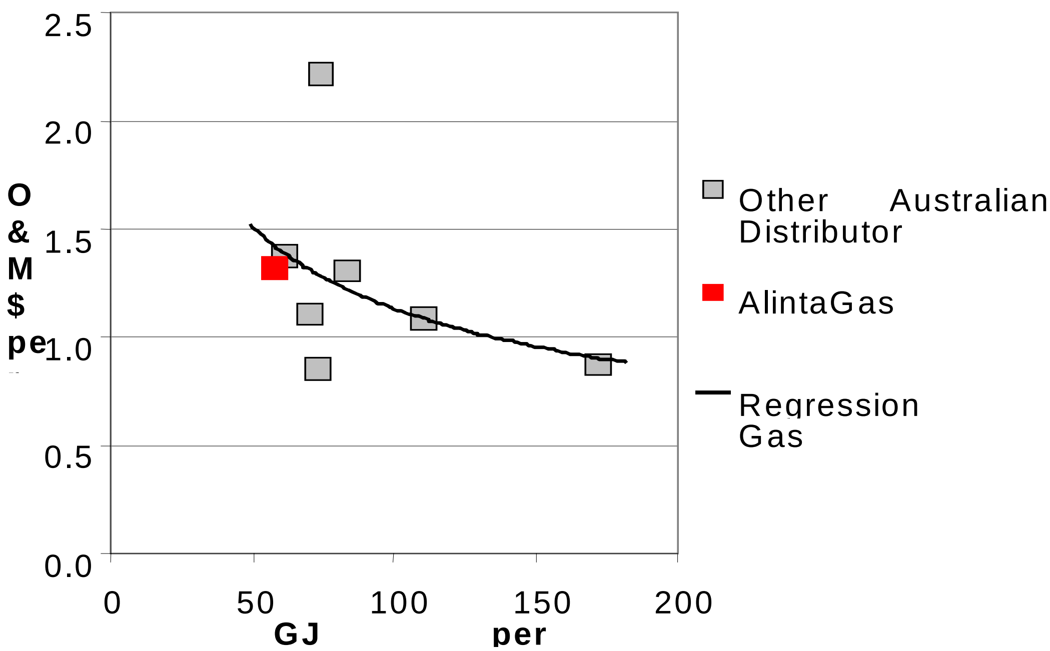
AGN's operating and maintenance cost per GJ delivered is above the national average. This is shown in Figure 7.3. Consumption per customer is a relevant factor here, not only in governing the numerator in the ratio of cost per GJ, but also indicating the seasonality of gas usage hence the utilisation of the network and associated costs. Western Australia's mild climate constrains the demand for reticulated natural gas; hence per Delivery Point GJ is relatively low.

Figure 7.3: Operating and Maintenance Cost per GJ Delivered



The relationship between O&M cost per GJ and average consumption (GJ per customer) is shown in Figure 4, together with a regression trendline for the reference group.

Figure 4: AGN's O&M Cost per GJ Regression Analysis



This analysis indicates that AGN's O&M cost per GJ is slightly below the regression trendline for other Australian gas distributors – ie AGN's above-average cost per GJ is a function of having Australia's lowest average consumption per customer rather than inefficient O&M costs.

ACCESS ARRANGEMENT INFORMATION
SCHEDULE 1

The Weighted Average Cost of Capital for Gas Distribution

31 March 2004

KPMG

Alinta Networks

The Weighted Average Cost of Capital for Gas Distribution

March 2004

This report contains 54 pages

Contents

1 Overview

1.1 Introduction and purpose of report

Alinta Networks Pty Ltd ("Alinta") owns and operates the Mid-West and South-West gas distribution systems in Western Australia ((hereinafter, collectively referred to as the "gas distribution system"). The gas distribution system is covered under the National Third Party Access Code for Natural Gas Pipeline Systems ("the Code" or "National Gas Code"). Coverage means that as the owner and operator of the gas distribution system, Alinta is required to lodge an Access Arrangement for approval by the relevant regulator. The relevant regulator in this instance is the Economic Regulation Authority ("ERA").

The Access Arrangement currently applying to the gas distribution system is due to expire on 31 December 2004. In accordance with the requirements of the Code, Alinta must submit a revised Access Arrangement to the ERA for approval, to take effect on 1 January 2005.

Alinta has appointed KPMG to provide advice and recommendations on what constitutes an appropriate Rate of Return for the gas distribution system. Under section 8.30 of the National Gas Code, the Rate of Return is one of the inputs required for the determination of Reference Tariffs for a covered pipeline.

This report sets out our recommendations on the appropriate Rate of Return for Alinta's gas distribution system, and the basis for our conclusions.

1.2 Pre-tax real WACC formulation

We have estimated a Rate of Return for Alinta's gas distribution system as a pre-tax real Weighted Average Cost of Capital ("WACC"), defined as follows:

$$\textbf{Pre-tax real WACC} = \{(1+\textbf{Pre-tax nominal WACC \%}) / (1+\textbf{CPI})\} - 1$$

Where

$$\textbf{Pre-tax nominal WACC \%} = K_e * 1 / \{1-t*(1-\gamma)\} * E/V + K_d*D/V$$

And

t	represents the corporate tax rate
γ	or "gamma" represents the average value attributable to imputation tax credits
K_e	represents the post-tax nominal cost of equity as determined under the Capital Asset Pricing Model ("CAPM")

K_d represents the pre-tax nominal cost of debt

E/V and D/V represent the weightings of equity and debt, respectively, in the capital structure of the business

1.3 Conclusions

KPMG considers that an appropriate rate of return to adopt for the purpose of setting the revenue stream of Alinta's gas distribution system in accordance with the requirements of the National Gas Code is currently a pre-tax real WACC of **8.5%.**

Our preferred estimate is drawn from a feasible range of 8.0% to 8.7% for the pre-tax real WACC, which in turn, has been estimated from the underlying parameter value ranges discussed in this report and summarised in the table below.

Table 1: Pre-tax real WACC – parameter estimates

Parameter	
Nominal risk free rate *	5.9%
Real risk free rate *	3.6%
Inflation expectation (implied)	2.2%
Asset beta	0.40 - 0.52
Equity beta	1.00
Debt beta	0.00 - 0.20
Market risk premium	6.0% - 8.0%
Equity proportion	40%
Debt proportion	60%
Pre-tax cost of debt	7.3% - 7.7%
Debt margin *	1.4% - 1.8%
Corporate tax rate	30%
Value of imputation credits	50%

** estimate will be subject to movements in interest rates at the time of the ERA's final determination*

In selecting a point estimate from within the feasible range, KPMG has taken into account the weight of evidence from independent and authoritative experts on the current misapplication of access regulation. This evidence is outlined in Section Two.

The arguments in support of this are best summarised in the findings of the Productivity Commission's ("PC") inquiry into the effectiveness of Australia's national access regime. In its final report, the PC identified the potential for access regulation to deter investment in essential infrastructure as the key risk to continued investment in infrastructure in Australia.

The PC noted that irrespective of how well regulators perform their task, the determination of efficient access prices was a formidable task, particularly given that many of the tools and methodologies available to regulators to set access prices were inherently imperfect. Furthermore, the consequences of "getting it wrong" can have significant adverse ramifications for infrastructure investment and economic welfare. In this context, the PC urged regulators to not be "*too ambitious*" in terms of their attempts to remove perceived monopoly rents.

KPMG considers that the following statement, extracted from the PC's 2000-01 Annual Report, appropriately summarises the approach that regulators should take:

> *"Given uncertainties and information difficulties, there are limits to what regulators can achieve. Rather than aiming for an ideal, but unattainable outcome, the public policy goal should be a set of regulatory arrangements that will improve efficiency through time and that will reduce some of the bigger risks of making regulatory errors. A framework is needed in which regulators are encouraged to intervene only when significant improvements in efficiency are in prospect and not be overly ambitious in finetuning the prices they regulate… The Commission's recent inquiries have revealed a need to re-balance the emphasis away from achieving immediate gains for users and consumers from existing infrastructure – much of it government owned or previously government owned – to a regulatory framework that will also facilitate efficient investment in augmented and new facilities."*

KPMG believes that a pre-tax real WACC of 8.5% would, in the current environment, appropriately balance the interests of Alinta and its customers, and provide appropriate incentives for investment.

1.4 Qualifications and disclaimer

This report has been prepared by KPMG on the basis of information available as at the date of this report. Nothing in this report should be taken to imply that KPMG has verified any information supplied to us, or has in any way carried out an audit of the books of accounts or other records of Alinta for the purposes of this report. We have considered and relied upon information from a range of sources, including information provided by Alinta, which we believe to be reliable, complete and not misleading. We have no reason to believe that any material facts have been withheld from us but do not warrant that our inquiries have revealed all of the matters which an audit or extensive examination might disclose.

In accordance with KPMG's policy, we are obliged to advise that neither KPMG nor any member nor employee undertakes responsibility in any way whatsoever to any person or organisation (other than Alinta) in respect of the information set out in this report, including any errors or omissions therein, arising through negligence or otherwise, however caused.

2 Putting the cost of capital into context

KPMG's estimate of the cost of capital for Alinta's gas distribution system recognises that:

- there is now a significant body of opinion from independent and legal bodies that regulatory decisions need to give greater weight to investment incentives and the provision of incentives consistent with those found in workably competitive markets; and
- the inevitable imprecision of cost of capital estimates, including the methodological limitations associated with approaches such as the CAPM, mean that the estimated cost of capital needs to be applied and interpreted with care. This is particularly relevant in a regulatory context because the impacts are magnified.

The first of these issues is addressed below, while the second is addressed in the context of the parameter analysis that follows this section.

2.1 Recent regulatory developments

Recent events have provided greater clarity on what should be the objectives of regulation. These have included the:

- PC's report on its Review of the National Access Regime[1] and the Government's Response[2];
- PC's draft report on the Review of the Gas Access Regime[3];
- Parer Report[4];
- Minister Ian Macfarlane's Statement of Reasons in his Final Decision[5] to revoke coverage of parts of the Moomba-Sydney Pipeline overturning the National Competition Council ("NCC")'s Final Recommendations;
- Epic Decision[6];

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[1] Productivity Commission, Review of the National Access Regime: Inquiry Report, 28 September 2001.
[2] Government Response to the Productivity Commission Review of the National Access Regime, released 17 September 2002.
[3] Productivity Commission, Review of the Gas Access Regime: Draft Report, Canberra, December 2003.
[4] Council of Australia Governments Energy Market Review Panel, Towards a Truly National and Efficient Energy Market: Final Report [Parer Report], 20 December 2002.
[5] Final Decision: Applications for Revocation of Coverage on Certain Portions of the Moomba-Sydney Pipeline System, 19 November 2003.
[6] *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231.

- The Australian Competition Tribunal ("ACT")'s decision on an appeal by Epic Energy in relation to the ACCC's decision on the Moomba to Adelaide pipeline[7]; and
- The ACT's decision on an appeal by GasNet[8].

These statements represent reassertions of the objectives of regulation from authoritative and independent sources.

2.1.1 The Productivity Commission

Review of the National Access Regime

The first and one of the strongest reassertions of the objectives of regulation came from the PC's Review of the National Access Regime, which was intended as an interim assessment of the effectiveness of the regime after five years of operation. One of the major themes of this assessment was the issue of "regulatory error" risk, and the realisation that the potential costs associated with too little infrastructure investment are far greater than those associated with too much investment. In short, there is asymmetry in the consequences of regulatory pricing errors:

> *"Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions …*
>
> *[and] given the asymmetry in the costs of under- and over-compensation of facility owners, together with the informational uncertainties facing regulators, there is a strong in principle case to 'err' on the side of investors".*

It is in this vein that the PC provided a clear warning against an excessive focus on the removal of so-called "monopoly rents" from the revenue streams of facility owners, quoting a submission to the review by Network Economics Consulting Group ("NECG"), which stated:

> *"In using their discretion, regulators effectively face a choice between (i) erring on the side of lower access prices and seeking to ensure they remove any potential for monopoly rents and the consequent allocative inefficiencies from the system; or (ii) allowing higher access prices so as to ensure that sufficient incentives for efficient investment are retained, with the consequent productive and dynamic efficiencies such investment engenders.*
>
> *There are strong economic reasons in many regulated industries to place particular emphasis on ensuring the incentives are maintained for efficient investment and for continued productivity increases. The dynamic and productive efficiency costs associated with distorted*

[7] Application by Epic Energy South Australia Pty ltd [2003] AcompT 5, 10 December 2003.
[8] Application by GasNet Australia (Operations) Pty Ltd [2003] AcompT 6, 23 December 2003.

incentives and with slower growth in productivity are almost always likely to outweigh any allocative efficiency losses associated with above-cost pricing. (sub. 39, p. 16)"

As a result the PC review highlighted the need to modify implementation of the regime and made 33 recommendations to improve its operation. In particular it identified as a:

"threshold issue, the need for the application of the regime to give proper regard to investment issues" and "the need to provide appropriate incentives for investment"[9]. *The Commonwealth Government's response*

This was supported by the Commonwealth Government's response: it decided to make changes to the Trade Practices Act which "*endorse the thrust*" of the PC's recommendations.[10] In particular, it will modify the regime to:

- Include a clear objects clause:

  "The objective of this part is to promote the economically efficient operation and use of, and investment in, essential infrastructure services thereby promoting effective competition in upstream and downstream markets…"

- Insert pricing principles:

  "The ACCC must have regard to the following principles:

  (a) that regulated access prices should:

  (i) be set so as to generate expected revenue for a regulated service or services that is ***at least sufficient*** *[our emphasis] to meet the efficient costs of providing access to the regulated service or services;*

  (ii) include a return on investment commensurate with ***the regulatory and commercial risks involved*** *[our emphasis]…"*

- Include a provision for merit review of decisions by the ACCC on proposed undertakings.

The Review of the Gas Access Regime

More recently, the PC has argued in its Draft Report on the Review of the Gas Access Regime that:

[9] PC, Review of the National Access Regime: Inquiry Report, 28 September 2001, p.xxii.
[10] Commonwealth Government, "Government Response to Productivity Commission Report on the Review of the National Access Regime: Interim Response", September 2002, p. 1.

> *"…there are problems with the current regime, mainly arising from the considerable costs it imposes and its potential to distort and deter investment."*[11]
>
> *"There is uncertainty about the regulatory outcomes. The building block and incentive regulation approaches used to assess access arrangements are intrusive and costly for service providers and have a high potential for regulatory error because of uncertainty about the multitude of assumptions and parameters used."*[12]

The Draft Report on the Review of the Gas Access Regime identified setting the ex ante regulatory rate of return as one of the key uncertainties.

The PC's concerns regarding regulatory implementation has continued to be reinforced by the PC's Chairman, Gary Banks, who recently highlighted the *"problem of regulatory overreach, or undue ambition"*, expressed the need for *"the requisite policy humility for such abstention"*, and warned against the *"seductiveness of controlling 'market power'"*[13].

2.1.2 The Parer Report

More recently, the Parer report on the Energy Market Review has called for a less intrusive approach to utility regulation. It concluded that there are *"distorted and inappropriate signals from the current network regulation framework."*[14] It also noted *"that future debate would be most effective if it focussed on moving regulation to a less intrusive form."*[15]

2.1.3 The Commonwealth Government

In addition to endorsing the PC's findings on the review of the National Access Regime, the Commonwealth Government has been providing its views on how the Gas Code should be interpreted.

The Minister for Industry Tourism and Resources, Ian MacFarlane, recently overturned the NCC's recommendation on the application for revocation of coverage of certain portions of the Moomba-Sydney Pipeline ("MSP") System.[16] Instead, the Minister decided that coverage of part of the MSP Mainline (the part that extends from Moomba to Marsden) was to be revoked. This decision is now understood to be the subject of several appeals to the ACT.

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[11] Productivity Commission, Review of the Gas Access Regime: Draft Report, December 2003, page XXV.

[12] Ibid., page XXVIII.

[13] Gary Banks, "The good, the bad and the ugly: economic perspectives on regulation in Australia", Address to the Conference of Economists, Business Symposium, 2nd October 2003, page 10.

[14] Council of Australian Government's Energy Market Review Panel, Towards a Truly National and Efficient Energy Market, 20 December 2002, p. 12. This was quoted by the ACCC in its submission to the PC Review of Gas Access Regime, September 2003, p.46.

[15] Ibid., p. 16.

[16] Final Decision: Applications for Revocation of Coverage on Certain Portions of the Moomba-Sydney Pipeline System, 19 November 2003.

While the Minister's decision relates to a case for lifting regulation – and it follows over 20 (mostly successful) revocation applications – the Minister in his Statement of Reasons emphasised a number of important points of regulatory implementation. The Minister stressed the need to move away from *"a presumption of access regulation or monopoly service provision"* and to provide evidence of the *"actual circumstances"* of pipelines as opposed to making a *"generic"* assessment or any assessment that *"bears limited relationship to the market realities"*, or arguing from a *"theoretical proposition."*[17]

The decision therefore highlighted the need for regulators to exercise their powers with a recognition of the commercial situation and market realities.

2.1.4 Judicial decisions

There has been a series of recent judicial decisions that have assisted in clarifying the role of the regulator and how access regulation should be applied.

The Epic Decision

The Western Australian Supreme Court ordered the Western Australian Independent Gas Access Regulator – the predecessor to the ERA - to revise its Draft Decision for the Dampier-Bunbury Natural Gas Pipeline's ("DBNGP") access arrangement to be more in line with the objectives of the regulatory regime. More specifically, in applying the Gas Code to set revenues for regulated gas businesses, the regulator is bound by the considerations in section 2.24 over all other parts of the Gas Code. That is to say, the regulator must take into account the interests of the Service Providers, Users and Prospective Users, and the public interest[18].

In particular, the Court considered that the Western Australian regulator (and by implication other regulators in Australia, given the similarity in the approaches they are adopting) have been approaching regulation in a way that is reflective of an underlying "perfect competition" model - which is inconsistent with the Gas Code. In contradistinction, the Court considered that regulation should be based on a model of "workable competition".

What the Epic Decision highlights is the need to regulate in accordance with the fundamental objectives of the Hilmer reforms, from which the regulatory regime and the Gas Code are descended. It notes: "*it would be surprising if what was contemplated was a theoretical concept of perfect competition, as the subject matter involves very real-life commercial situations*" [19]. It goes on to note that "*Workable competition seems far more obviously to be what is contemplated. This is clearly consistent with the approach of the Hilmer Report …*".

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[17] Statement of Reasons, 19 November 2003, sections 56-58, page 15.

[18] Noted in Re Dr Ken Michael AM: ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 ("the Epic decision"), at 85. The WA Supreme Court has rightly highlighted that this section echoes the principles set out in the Hilmer Report, at 97.

[19] *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231, para. 124.

There is an issue of specific relevance to Alinta's gas distribution system in this context. In applying the principles emerging from the Epic Decision in its Final Decision, the regulator appeared to have restricted the application of the principle that it is bound by the factors in Section 2.24 as fundamental considerations, primarily to its assessment of the Initial Capital Base. In other words, the regulator's interpretation of the Epic decision was that the requirement to be bound by the factors in Section 2.24 as fundamental considerations, applied only its assessment of the Initial Capital Base but not to other parameters underlying the reference tariffs. For example, the final decision indicates that the regulator has assessed the cost of capital by making a *"best estimate of the true cost of capital"* as required under Section 8.2(e) of the Code, rather than by considering the factors in Section 2.24.

While the regulator has adopted this narrow interpretation of the Court's decision in making its Final Decision on the DBNGP, it is not an option that is open to the ERA when assessing Alinta's access arrangements. The requirement to observe Section 2.24 was discussed in the context of the Initial Capital Base in the Epic Decision presumably because that was the key issue of contention in that dispute. It does not follow from this that the requirement to observe Section 2.24 in assessing access arrangements generally should be restricted to considering the Initial Capital Base.

For the purpose of Alinta's access arrangements, the Initial Capital Base has been set and does not require approval by the ERA as was the case with the DBNGP. However, the ERA is still required to treat the factors in Section 2.24 as fundamental considerations in assessing other terms and conditions – such as the Rate of Return - in Alinta's proposed access arrangements.

The Australian Competition Tribunal

Two recent ACT decisions have offered important clarifications on issues such as the role and powers of the regulator and the way in which access arrangements should be assessed under the Code.

In December 2003, the ACT handed down its decision on Epic Energy's appeal against the ACCC's refusal to approve its access arrangements for the Moomba Adelaide pipeline ("MAP"). Some of the guiding principles emerging from this decision concern how the regulator should select estimates under circumstances where a range of possible values exist:

- regulators must give clear and substantiated reasons for reaching their conclusions regarding the values they select where a range of possible values exist;[20]

- where a range of possible values exist, there is no requirement in the Code that the lowest value should be selected.[21] The Tribunal specifically stated that:

[20] Application by Epic Energy South Australia Pty ltd [2003] AcompT 5, 10 December 2003, para. 32, 48, 84.
[21] Application by Epic Energy South Australia Pty ltd [2003] AcompT 5, 10 December 2003, para. 92.

"*Epic must be allowed the opportunity to earn a revenue stream that recovers the efficient costs of operating the Reference Service, and the need to replicate the outcomes of a competitive market does not demand the use of the lowest indicated price based on general, albeit informed, inquiries."*

- under conditions of uncertainty, a reasonable and prudent service provider would not select a value that lies at the low end of a range of possible values. Doing so creates an asymmetric exposure to risk.[22]

Important principles regarding the role and powers of the regulator can also be drawn from the recent ACT decision on GasNet's appeal against the ACCC's final decision on its access arrangements. In this decision, the Tribunal expressed the view that it is beyond the power of the regulator not to approve the service provider's access arrangements where the arrangements proposed fell within reasonable and acceptable ranges:

> *"…where the AA proposed by the Service Provider falls within the range of choice reasonably open and consistent with Reference Tariff Principles, it is beyond the power of the Relevant Regulator not to approve the proposed AA simply because it prefers a different AA which it believes would better achieve the Relevant Regulator's understanding of the statutory objectives of the Law."*[23]

The view expressed by the Tribunal reinforces the Court's finding in the Epic decision that there is no single correct value for most of the parameters used in setting reference tariffs. In this context, it is not open to the regulator to reject the service provider's proposed access arrangements and replace it with its own judgments as to what is more appropriate, unless it is found that the proposals do not comply with the factors listed in Section 2.24 of the Code.

Importantly, these concepts can be extended to the regulator's assessment of the Rate of Return. At paragraph 42 of the decision, the Tribunal stated that:

> *"Contrary to the submission of the ACCC, it is not the task of the Relevant Regulator under s 8.30 and s 8.31 of the Code to determine a 'return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service'. The task of the ACCC is to determine whether the proposed AA in its treatment of Rate of Return is consistent with the provisions of s 8.30 and s 8.31 and that the rate determined falls within the range of rates commensurate with the prevailing market conditions and the relevant risk."*

Having clarified that the regulator's role is not to set the Rate of Return but to assess if it falls within acceptable ranges under the provisions of Section 8.30 and 8.31 of the Code, the Tribunal concluded that:

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[22] Application by Epic Energy South Australia Pty ltd [2003] AcompT 5, 10 December 2003, para. 62, 94.

[23] Application by GasNet Australia (Operations) Pty Ltd [2003] AcompT 6, 23 December 2003, paragraph 29.

> *"When the proposed AA was delivered by GasNet to the ACCC, insofar as it contained a Rate of Return which was used to determine the Reference Tariff established by the use of the CAPM, the only issue for the ACCC to determine in respect of the Rate of Return was whether GasNet had used the model correctly. That is, whether it had used the CAPM to produce a Rate of Return which was consistent with the conventional use of the model. If GasNet had done so, then there was no occasion to refuse to approve the proposed AA on the basis that the Rate of Return had not been determined on a basis which was consistent with the objectives contained in s 8.1."*[24]

Collectively, KPMG considers that the following guiding principles on access regulation emerge from recent judicial precedents:

- the role of the regulator is not to set the terms of the service provider's access arrangements, but to assess if the access arrangements are consistent with the provisions of the Code;

- the outcomes of a workably competitive market are the appropriate benchmark against which to make these assessments;

- there is no requirement that regulators must establish reference tariffs based on the lowest value for any underlying parameters. Under conditions of uncertainty, a reasonable and prudent service provider would not pick the lowest value since this would expose the service provider to the highest risk of under-estimation;

- the regulator can only reject the service provider's access arrangements if the proposals are found to be inconsistent with the provisions of the Code;

- there is sufficient uncertainty regarding the principles that are applied in setting reference tariffs such that *"…different minds, acting reasonably, can be expected to make different choices within a range of possible choices which nonetheless remain consistent with the Reference Tariff Principles.*[25]*"*; and

- given the uncertainty noted above, the regulator cannot reject the service provider's access arrangements because the regulator prefers a different access arrangement that it considers are more consistent with the provisions of the Code.

2.2 Conclusion

KPMG's application of the CAPM, and our estimate of the cost of capital for Alinta's gas distribution system, is consistent with recent regulatory developments, which have reasserted the proper objective of regulation.

[24] Application by GasNet Australia (Operations) Pty Ltd [2003] AcompT 6, 23 December 2003, paragraph 45.

[25] Application by GasNet Australia (Operations) Pty Ltd [2003] AcompT 6, 23 December 2003, paragraph 29.

There is now a significant independent body of opinion that demonstrates the importance of avoiding regulatory error and the nature of that error as posing significant risks to a regulated business's future investments, and hence the level of economic welfare.

In addition, there is now sufficient judicial precedent that confirms that the role of the regulator is not to set the terms and conditions of the service provider's access arrangements, but to assess if the access arrangements fall within reasonable and acceptable ranges, and are consistent with the provisions in the Code. There is also no requirement that the lowest value of underlying parameters must be adopted in order for reference tariffs to comply with the requirements of the Code.

As the remaining sections in this report point out, estimation of WACC is an inherently imprecise exercise, given both the methodological uncertainties underlying the theory and limitations in relation to the measurement of underlying parameters. Such considerations are relevant to the ERA's assessment of the reasonableness of the WACC that we have recommended for Alinta's gas distribution system.

We consider that application by the ERA of the set of principles we have used and highlighted above would provide an outcome that is consistent with the correct interpretation of the Code. It would also encourage an investment environment that is far more conducive to maximising the economic welfare both of consumers and infrastructure owners than alternative approaches, thereby addressing the concerns of PC and the Government.

3 The cost of capital

3.1 Introduction

The cost of capital is the rate of return required by the marginal investor in a firm (i.e. the last investor willing to contribute funds). Equivalently, it represents the minimum return on capital that a firm must expect to earn on its investments to attract new capital and to maintain its current value.

The cost of capital of a firm is typically measured by reference to the current cost of raising funds via the various classes of its capital (e.g. equity, debt, etc.), each weighted by the target proportion of each class of capital to the total market value of capital of the firm. Hence, the cost of capital of a firm is often referred to as a WACC.

In estimating WACC, the CAPM is widely applied to estimate the cost of equity[26]. The CAPM is based on the assumption that an investor in a risky asset requires additional return to compensate for bearing additional risk. In simple terms, the CAPM asserts that the required rate of return on a risky asset is a function of the risk free rate of return (Rf) plus a risk premium that reflects the return on a well-diversified portfolio of risky assets over the risk free rate (Rm – Rf), scaled by the "beta" of the risky asset.

Therefore, the required rate of return for equity securities (K_e) is determined as follows:

$$\mathbf{K_e = Risk\ free\ rate + Risk\ premium}$$

$$\mathbf{K_e = R_f + \beta_e * \{R_m - R_f\}}$$

Beta (denoted by β_e) is a measure of the risk of the risky asset relative to the market index. In theory, the only risks that are captured by beta are those risks that relate to the co-movement of returns with the overall market, that cannot be eliminated by the investor through diversification. Such risks are referred to as systematic, undiversifiable or uninsurable risks. Portfolio diversification is assumed to eliminate all other risks. In practice, however, there is evidence to suggest that investors are not diversified to the extent the CAPM assumes[27]. For this reason, some investors are likely to require compensation for risks that are considered to be diversifiable under the CAPM.

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[26] There are a number of other theories that can be applied to estimate the cost of equity. However, the CAPM remains the most popular theory.

[27] For example, Goeztman, W. and A. Kumar, *Diversification Decisions of Individual Investors and Asset Prices*, January 2004, unpublished working paper Yale School of Management, conducted an empirical study of 60,000 individual investors during a six year period (1991-1996) and found that the vast majority of investors in their sample were under-diversified. The authors suggest that if investors systematically hold less than fully diversified portfolios, they are likely to demand compensation for the idiosyncratic risk in their equity portfolios. Further analysis suggested that the diversification decisions of these investors will also be reflected in asset prices. In addition, we are also aware of research which has found that the non-systematic risk related to the risk

The risk-return concepts underlying the CAPM are applicable to any risky asset. Therefore, the required rate of return for risky debt securities can be similarly estimated:

$$\mathbf{K_d = Risk\ free\ rate + Risk\ premium}$$

$$\mathbf{K_d = R_f + \beta_d * (R_m - R_f)}$$

However, in practice, the beta for debt securities (β_d) is much more difficult to measure compared with the beta for equity securities (β_e) given the relatively lower level of liquidity and depth in many debt markets.

In addition to the CAPM, capital structure theory is also applied to estimate the target weights that are applied to the cost of equity and the cost of debt in estimating WACC. Capital structure theory focuses on the factors which influence the mix of capital employed by the firm.

In the context of revenue setting by regulators, the cost of capital is effectively converted into a cash flow item. That is, it is applied to a measure of the value of the regulatory asset base, and the result is then added to other revenue building blocks to derive a measure of the required revenue of the regulated entity. In order to ensure that the revenue derivation formula is internally consistent, it is clear that the cost of capital cannot be considered in isolation of the definition of other components of overall revenue determination in regulatory decisions. Care must be taken to ensure this mutual dependency is recognised. This also applies to the treatment of inflation, risk and tax. It is in this context that capital structure theory and the CAPM also intersect. For example, the variance of possible future costs influences capital structure choice, the cost of debt and possible cash flows under conditions of distress. Consequently both the cost of capital and the expected operating costs are influenced by variance however the CAPM focuses only on the non-diversifiable element of variance.

Estimating the cost of capital may initially require a simple application of the CAPM formula, however, in practice, the application of the CAPM is complicated by several factors. For example:

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of the firm has increased in recent times, and due to this, elimination of non-systematic risk is no longer possible by holding a portfolio of 20 to 30 stocks. (refer Campbell, Lettau, Malkiel and Xu, *Have Individual Stocks Become More Volatile? An Empirical Exploration of Idiosyncratic Risk*, Journal of Finance, Vol. LVI, No. 1, February 2001). Finally, Malkiel and Xu (2002) also postulate that if there are investors who cannot hold the market portfolio for exogenous reasons (i.e. they are not diversified to the extent the CAPM presumes), other remaining investors will also be unable to hold the market portfolio (since the sum of the two make up the whole market). Under such a scenario, investors will care about total risk, not just market risk. (refer Malkiel, B and Y. Xu, *Idiosyncratic risk and security returns*, December 2002, unpublished working paper).

- whilst various tests of the CAPM have generally lent support to the broad concepts of risk that underpin the model, empirical testing has also shown that the CAPM does not fully explain security pricing and therefore the cost of equity[28];
- there are significant information constraints, estimation challenges and uncertainties in applying such a model in practice. The impacts of these challenges and methodological limitations are magnified in a regulatory context where an important component of revenues and profitability is underpinned by the regulatory allowed WACC;
- in theory, a number of parameters underpinning the CAPM should reflect forward-looking estimates, which are unobservable. A considerable amount of careful judgment and pragmatism is required in selecting appropriate parameter values; and
- the model requires consistency in the treatment of components of the expected cash flow items and components of the cost of capital in circumstances where distinctions are blurred in practice. The treatment of a number of cash flow "risks" are cases in point.

Given the challenges in applying guidance from theoretical models, and the importance of the cost of capital to infrastructure investors and the overall level of investment, it is important that the WACC be set in a way that takes due account of these factors and is furthermore consistent with regulatory objectives. A number of recent regulatory developments have been particularly important in highlighting the proper understanding of regulatory objectives, and these were reviewed briefly in section 2.

3.2 WACC formula

3.2.1 Post-tax nominal ("textbook") WACC

WACC can be expressed in a variety of ways. For each definition, there is a corresponding cash flow definition.

The standard "textbook" WACC formula is set out below.

$$\textbf{Post-tax nominal WACC} = K_e * E/V + K_d*(1-t)*D/V$$

where t represents the corporate tax rate.

3.2.2 Officer WACC

In Australia, an "imputation adjusted" version of the post-tax nominal WACC is often applied. This formula is also commonly known as the "Officer" definition by reason of its association with Professor Robert Officer:

$$\textbf{WACC} = K_e * (1-t)/\{1-t*(1-\gamma)\} * E/V + K_d*(1-t)*D/V$$

[28] The Roll critique also highlights the difficulties of testing the theory; Richard Roll, 1997, "A critique of the asset pricing theory's test", Journal of Financial Economics, 4.

Where t represents the corporate tax rate and γ or "gamma" represents the average value attributable to imputation tax credits. The term $(1-t)/\{1-t^*(1-\gamma)\}$ in this formula is the imputation adjustment factor.

The Officer WACC is similarly expressed in post-tax nominal terms.

3.2.3 Pre-tax real WACC

The pre-tax real WACC that has been applied for revenue setting in many regulatory decisions around Australia is based upon the Officer WACC, grossed up by 1 minus the statutory corporate tax rate to obtain the pre-tax nominal WACC:

$$\textbf{Pre-tax nominal WACC \%} = K_e * 1/\{1-t^*(1-\gamma)\} * E/V + K_d * D/V$$

and then adjusted for inflation:

$$\textbf{Pre-tax real WACC} = \{(1+\text{Pre-tax nominal WACC \%}) / (1+CPI)\} - 1$$

3.2.4 Pre-tax real framework and transformation issues

As noted above, in transforming the Officer WACC into a pre-tax real WACC, the early regulatory decisions in Australia adopted the sequence of firstly grossing up the Officer WACC by 1 minus the statutory corporate tax rate, and secondly adjusting the result for inflation. Some regulators expressed concern regarding this transformation sequence. In addition, regulators such as the ACCC and the ESC in Victoria became increasingly concerned that businesses were being over-compensated for their actual tax obligations under a pre-tax WACC approach (because tax concessions such as accelerated tax depreciation are not captured by the statutory corporate tax rate applied). Together, these concerns led to a move towards a revenue setting framework that seeks to explicitly calculate the cost of tax (known as the post-tax framework).

There are essentially two alternative transformation sequences that could be applied to convert a nominal post tax WACC to a real pre-tax WACC:

- convert the post-tax nominal WACC into a pre-tax nominal WACC by grossing up by a factor of (1-t), then deflate the pre-tax nominal WACC to obtain a pre-tax real WACC. This is the methodology described above and is known as the forward or market transformation; or

- deflate the post-tax nominal WACC to obtain a post-tax real WACC, then convert the post-tax real WACC into a pre-tax real WACC by grossing up by a factor of (1-t). This approach was initially introduced by Macquarie Risk Advisory Services in advice provided to the ACCC and the ESC in their 1998 review of the Victorian gas access arrangements, and is referred to as the reverse transformation approach.

Due to the interaction between tax and inflation, these transformation approaches produce different results. In theory, it is accepted that neither approach will produce a post-tax nominal cash flow return on assets that equates to the targeted post-tax nominal WACC. Where asset lives for regulatory purposes and tax purposes are aligned, there is a tendency for the forward transformation approach to produce a cash flow return on assets that *exceeds* the target post-tax nominal WACC, and this tendency is magnified when tax depreciation allowances are high relative to regulatory depreciation allowances. By contrast, the reverse transformation approach tends to produce a cash flow return on assets that *understates* the target post-tax nominal WACC where asset lives for regulatory purposes and tax purposes are aligned. However, it would also appear that this tendency reduces where accelerated tax depreciation allowances are high relative to regulatory depreciation allowances.

To illustrate the above points, we have constructed a numerical example based on an asset costing $100 with a 10 year economic life. We have assumed that the target post-tax nominal WACC (i.e. the textbook WACC) of 7.38% and that the inflation rate is 2.5% p.a. For simplicity we have assumed zero operating costs and that the straight-line depreciation methodology is adopted.

The table below highlights how the post-tax cash flow return on assets (determined through an IRR analysis) changes under the forward and reverse transformation approaches, as the assumed tax depreciation life is varied.

Table 2: Change in post-tax cash flow return

Economic life (years)	Tax life (years)	Target post-tax cash flow return = 7.38%	
		Post-tax cash flow return – Forward transformation	Post-tax cash flow return – Reverse transformation
10	10	7.52%	6.76%
10	9	7.68%	6.90%
10	8	7.85%	7.06%
10	7	8.03%	7.23%
10	6	8.23%	7.41%
10	5	8.45%	7.61%
10	4	8.70%	7.83%
10	3	8.97%	8.08%
10	2	9.28%	8.36%
10	1	9.63%	8.67%

As highlighted in the foregoing discussion, both transformation approaches suffer from some bias. In one sense, the forward transformation approach is arguably preferable to the reverse transformation approach since the latter suffers from the fundamentally flawed assumption that tax is levied in real cash flows when this is not in fact the case.

Neither approach can, however, be argued to be "better" than the other on the basis of the "accuracy" of the results they each produce. As we have discussed, however, imprecision is an inherent feature of the entire revenue setting process and in the estimation of the appropriate rate of return. Imprecision is therefore not a sufficient reason for abandoning a formula-based approach to allowing for tax in favour of an explicit cash flow based approach.

Given the removal of accelerated tax depreciation benefits for assets put in place post- 21 September 1999 and changes to tax rules to align asset lives for tax and accounting purposes resulting from the Ralph Business Taxation Review, the gap between tax depreciation allowances and regulatory depreciation allowances can be expected to progressively diminish. Accordingly, over time, the effective tax rate (taking into account tax depreciation) and the regulatory tax rate should converge. This means that the pre-tax real WACC derived using the forward transformation method should become a less biased estimate of the target post-tax nominal return. On this basis, we prefer the forward transformation approach.

Admittedly, the pre-tax real WACC derived using a forward transformation approach and incorporating the full statutory corporate tax rate, would still produce above-target returns in the transitional period. Nevertheless, we believe that it is inappropriate for regulators to confiscate the benefits of accelerated tax depreciation from regulated businesses on the basis that these benefits reflect the residue of those that previous policy makers explicitly sought to deliver to facility owners through the accelerated depreciation schemes put in place prior to the most recent round of business taxation reforms.

4 The risk free rate of return and inflation

There are two main issues currently surrounding the estimation of the risk free rate of return in the WACC:

- the appropriate term to maturity of the underlying risk free security; and
- the period over which the rate is measured.

4.1 Choice of proxy for the risk free asset

KPMG has estimated:

- the nominal risk free rate by reference to the yield on 10 year Commonwealth Government bonds, as currently represented by the benchmark May 2013 Commonwealth Government Bond; and
- the real risk free rate by reference to the yield on an Indexed Linked Government Bond with a term to maturity corresponding with that on the nominal risk free rate of return. This yield has been estimated by interpolating between the August 2010 and August 2015 Index Linked Government Bond yields.

Our approach is consistent with the majority of the regulatory determinations by various regulators around Australia. These decisions recognise that in Australia, the ten year Commonwealth Government Bond is commonly adopted as a proxy for the nominal risk free rate for the purposes of estimating WACC, given the good depth and liquidity of the market for this security. Furthermore, in investment analysis, it is generally accepted that the appropriate government bond is usually one with a maturity that most closely matches the life of the underlying investment.

Up until recently, the only regulator in Australia that has continued to reject the above approach has been the ACCC. The ACCC’s practice has been to adopt a risk free rate with a maturity matching the length of the regulatory period. We note that this issue has recently been resolved by the ACT decision on GasNet’s appeal against the ACCC’s revisions to its access arrangements. In that case, the Tribunal found in favour of GasNet that the ACCC’s use of the five year government bond rate as the risk free rate was inappropriate in the context of the CAPM.

4.2 Period of averaging for risk free rate

It has been the standard practice in regulatory determinations to adopt some period of historical averaging in estimating the risk free rate of return rather than an “on the day” rate. Given that the rates observed on any particular day could be temporarily influenced by market anomalies, KPMG agrees that some short term averaging of recent historical rates is desirable.

KPMG understands that the ERA's practice has been to adopt a 20 day period of averaging when measuring the risk free rate of return. In theory, the most recent interest rates embody the latest information about market conditions, and therefore, the longer the period of averaging, the less weight would be attached to the latest market rates. This has led some regulators to adopt a shorter period of averaging (e.g. 10 days). However, from a practical perspective, a period of averaging that is too short could create problems for a regulated that is intending to hedge over the sample period.

On balance, KPMG believes that there would be little material or practical benefit from shifting from the ERA's current practice of adopting a 20 day sampling period. What is necessary is that advance notice be given regarding the date on which the 20 day sampling period would commence or end to facilitate the regulated entity's forward planning with respect to hedging. The 20 day sampling period is also consistent with the approach adopted by the Essential Services Commission in Victoria ("ESC"), the Independent Pricing and Regulatory Tribunal ("IPART") and the Queensland Competition Authority ("QCA").

4.3 Inflation

KPMG has estimated the rate of expected inflation by inputting the nominal and real risk free rates of return into the Fisher equation, and solving for the implied inflation rate.

4.4 Conclusion

For the purposes of estimating an appropriate WACC, KPMG recommends the following values:

- a nominal risk free rate of **5.9%.** This rate reflects the yield on 10 year Commonwealth Government bonds, as currently represented by the benchmark May 2013 Commonwealth Government Bond, averaged over the 20 days to 9 December 2003; and

- a real risk free rate of **3.6%.** This rate reflects the yield on an Indexed Linked Government Bond with a term to maturity corresponding with that on the nominal risk free rate of return. Given that there is currently no Indexed Linked bond maturing in May 2013, this yield has been estimated by interpolating between the August 2010 and August 2015 Index Linked Government Bond yields, and averaging over the 20 days to 9 December 2003.

Collectively, the above rates imply an expected inflation rate of around **2.2%.**

5 The market risk premium

5.1 Introduction

KPMG supports the estimation of the market risk premium ("MRP") by reference to long term historical averages. The evidence that we have reviewed suggests that the appropriate range for the MRP is between 6% to 8%.

We are aware that there is a range of other methodologies available for estimating the MRP such as surveys and supply side approaches. However, we place a lower level of confidence on such estimates given our concern that they are likely to introduce even greater estimation error than the historical estimates.

While there is evidence of regulators adopting an MRP of 6% - which is at the low end of the range of values observed from long term historical averages - there is also considerable evidence to suggest that this figure may not be appropriate and does not represent a valid precedent. KPMG has some concerns that this "precedent" is more of a "follow-the-first-decision" outcome (admittedly in a difficult area) than the result of a rigorous review of the evidence combined with a recognition that it is less costly to err on the side of encouragement to invest than to discourage investment.

We note that as part of the 2003 Gas Access Arrangements Review, the Victorian gas distributors commissioned Professor Stephen Gray from the University of Queensland to advise on the appropriate value for the MRP. His paper, which strongly supported the adoption of an MRP estimate of 7%, was submitted as Attachment A of TXU's response to the ESC's Position Paper[29].

The evidence on the market risk premium has been presented and reviewed in numerous regulatory decisions since the ESC's first Gas Access Decision in 1998. KPMG's summary of this evidence and surrounding discussion is set out in Sections 5.2 and 5.3 below.

5.2 Empirical evidence – long term historical averages

Empirical evidence based on the historical market risk premium in Australia provides support for an MRP in the range of 6% to 8%[30]. Table 3 below sets out the measured historical MRP in Australia reported in various studies and research.

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[29] Refer S. Gray, Issues in Cost of Capital Estimation, 19 October 2001 downloadable at http://www.esc.vic.gov.au/PDF/2001/SubUQBS_GasPosPapOct01.pdf

[30] This same conclusion was arrived at by the Queensland Competition Authority ("QCA") after considering various historical measures of the MRP. Refer QCA, Proposed Access Arrangements for Gas Distribution Networks, October 2001, p.216.

Table 3: Measured historical MRP in Australia

Source	Period	Risk premium (%)
AGSM:		
Arithmetic average, incl October 1987	1974-1995	6.2
Geometric average, incl October 1987	1974-1995	4.1
Arithmetic average, excl October 1987	1974-1995	8.1
Geometric average, excl October 1987	1974-1995	6.6
Arithmetic average[31]	1974-1998	4.8
Geometric average	1974-1998	2.8
Arithmetic average, incl October 1987[32]	1974 – Sep 2000	6.2
Geometric average, incl October 1987	1974 – Sep 2000	4.4
Arithmetic average, excl October 1987	1974 – Sep 2000	7.7
Geometric average, excl October 1987	1974 – Sep 2000	6.4
Officer (1989) – arithmetic mean	1882 – 1987	7.9
Officer (1989) updated – arithmetic mean[33]	1882 – 2001	7.2
Officer[34]:		
Arithmetic mean	1946-1991	6.0 to 6.5
Hathaway (1996)[35]		
Arithmetic mean	1882-1991	7.7
Arithmetic mean	1947-1991	6.6
Gray (2001) (note 2)	1883 – 2000	7.3
Dimson, Marsh and Staunton (2000)[36]		
Geometric mean	1900 – 2000	7.6

Notes:

1. *Both arithmetic and geometric mean results are shown. Arithmetic average returns are generally considered to represent better estimates of future returns because they take into account more observations on realised returns. By contrast geometric average returns can be calculated by knowing only two observations.*
2. *Gray (2001) is based on an update of Officer's work as reported in S. Gray, Issues in Cost of Capital Estimation, 19 October 2001 downloadable at* *http://www.esc.vic.gov.au/PDF/2001/SubUQBS_GasPosPapOct01.pdf*

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[31] Refer ABN AMRO (1999) Submission to the Office of the Regulator General Victoria Regarding 2001 Electricity Distribution Price Review; the Cost of Capital Financing (Consultation Paper No. 4) p12. A copy of this is available at http://archive.esc.vic.gov.au/1999/electric_ConsPap4Resp_abnamro.pdf

[32] Referred to in independent expert report by Deloitte Touche Tohmatsu dated 19 December 2000 to Woodside Petroleum shareholders in relation to a takeover offer by Shell Investments.

[33] Refer ABN AMRO (1999) Op cit

[34] Officer, R.R. (1992), Rates of Return to Shares, Bond Yields and Inflation Rates: An Historical Perspective, as updated for a 1993 Seminar at the University of Melbourne.

[35] Refer ABN AMRO (1999), Op cit

[36] Dimson, Marsh and Staunton, "Twelve Centuries of Capital Market Returns", Business Strategy Review, 2000, Vol 11 Issue 2

In interpreting the evidence presented above:

- the high volatility of the market risk premium in the recent past suggests that it cannot be inferred that recent averages represent a departure from the long-term historical average. Given the nature of recent events, such as the so-called “tech-wreck” and September 11th, it is even more difficult to assume that risk has fallen (or risk aversion has fallen to offset this recent change) and the MRP is now below the historical average; and

- in addition, we must be wary of relying on post-1987 MRP data as the market index is biased downwards because it does not capture the average value of franking tax credits, which is non-zero.

The empirical study by Dimson, Marsh and Staunton (2000) referred to in Table 3 provides an Australian series from 1900 to 2000[37] and finds the arithmetic average market risk premium relative to long-term bonds to be 7.6% (8.6% relative to short term bills). Additionally it states that the average market risk premium for the 12 developed countries examined has been 7.2%.

The authors adjust this estimate downwards to reflect “today’s best guesses about future equity market volatility levels” (which they assume to be lower than historical figures). The adjustments lead to a market risk premium (over bills) of 8.1% for Australia and 6.7% over long-term bonds as the average for all 12 countries. The Australian adjustment was small compared with the adjustment for other countries. Interpolating for the premium over bonds rather than bills would mean a premium of around 7.1%. The authors then examine the historical risk premium over the first and second half of the century and note a decline in the second half. Based on this observation they postulate reasons and suggest that the premium may now be lower. Interestingly, however, they note that Australia was an exception – the market risk premium in the second half of the century was not lower.

Dimson et al (2000) cites a survey of 226 financial economists undertaken by Welch[38]. Those surveyed were asked to forecast the arithmetic equity risk premium over various time horizons. The mean forecast for 30 years was approximately 7%. By inference, the market risk premium for Australia would be expected to be at least at this level. This estimate is within the 6% to 8% range and does not signify a view by academics that the equity risk premium in the US has fallen to a range of 5% to 7%. As the article notes:

> *“These survey figures represent what is being taught in the world’s leading business schools and economics departments. As such they will also be widely used by finance professionals and corporate executives. Similarly they will be cited by regulators and used in rate-of-return regulation disputes.”*

[37] The source data is not independent of other Australian studies eg AGSM, Officer

[38] Ivo Welch (2000), “Views of Financial Economists on the Equity Risk Premium and Other Issues”, Journal of Business, 17 pp501 - 537

The Welch paper is discussed in the paper written by Gray which forms Attachment A to TXU's submission to the ESC's Position Paper.

The data presented below, and discussed in Gray's paper, reinforces the conclusions that:

- the appropriate range for the MRP is 6 to 8%; and
- there is no substantive evidence to support a decline in the risk premium below this range.

Gray's paper also re-iterates the benefit of a long term perspective in estimating the MRP and the challenge faced in forming a sound and supportable view that the MRP has changed recently.

There has been substantial variation in the MRP by decade, both in Australia and the US, as shown in Table 4 below.

Table 4: Comparison of MRP in Australia and the US, by decade

	USA[39]	Australia[40]
1926 – 1929	17.6%	11.2%
1930's	2.3%	5.7%
1940's	8.0%	6.4%
1950's	17.9%	13.5%
1960's	4.2%	9.6%
1970's	3.0%	0.4%
1980's	7.9%	7.9%
1990's	7.9%	2.9%

Taking a longer term view leads to a lower standard error of the estimated MRP. Table 5 below shows that over the period 1883 – 2000, the average MRP is 7.3% with a standard error of 1.56%, whereas the estimate from 1971 – 2000 is 4.8% but is much less reliable with a standard error of 4.4%. As Gray points out, the 4.8% average obtained for more recent decades is not statistically different from the longer term historical average.

[39] Anmin, M., Falaschetti, D., *Equity Risk Premium, Valuation Strategies*, January / February 1998, obtained at http://www.ibbotson.com/Research/papers/Equity_Risk_Premium/

[40] Updated data to 2000 from Officer, R. R. (1989), *Rates of Return to shares, Bond Yields and Inflation Rates: An Historical Perspective*, in Ray Ball, Phil Brown, Frank Finn and Bob Officer, *Share Markets and Portfolio Theory*, University of Queensland Press, pp. 207-211.

Table 5: Historical Australian Market Risk premium with varying start and finish years

Start Year	Finish Year	Mean %	Standard Error %
1883	2000	7.3	1.56
1883	1970	8.2	1.5
1971	2000	4.8	4.4

Source: Gray, S (2001), Issues in Cost of Capital Estimation, available at http://www.esc.vic.gov.au/PDF/2001/SubUQBS_GasPosPapOct01.pdf

Given the importance of the cost of capital to revenue determination and new investment, KPMG does not believe the ERA should be adopting a pre-emptive view (in the absence of sound evidence) that there has been a decline in the risk premium. Rather, the ERA should adopt a conservative approach that is consistent with the long term empirical evidence.

5.3 Views of Australian academics

KPMG notes that, faced with all available evidence, and their own research, a number of Australian academics have recommended an MRP in the 6 to 8% range:

Hathaway states that:

> *"The recommended range of values to use for the expected risk premium for the Australian equity market is 6.6 – 7.0% p.a. When using a single estimate for the Australian expected risk premium, the best such point estimate is 7% p.a. while the best post-war such estimate is 6.6% p.a."*[41]

In addition, Twite states that:

> *"While seeking a sufficiently large sample from which to obtain a 'reasonable' estimate of the market risk premium, we believe it is appropriate to adjust for the influence of 'unusual' events, such as October 1987. Excluding October 1987, the average risk premium is 6.4%"*[42]

Gray finds no statistical support for the hypothesis that the MRP has fallen:

[41] Hathaway, N. "Market Risk Premium", MBS seminar entitled Cost of Capital: Imputation Credits and other issues.

[42] Dr G. Twite, Senior Lecturer in Finance, AGSM in ABN AMRO "Submission to the Office of the Regulator General, Victoria, regarding 2001 Electricity Distribution Price Review: The Cost of Capital Financing", 4 June 1999, p.13.

> *"The average market risk premium was 7.3% per annum over the period 1883 to 2000. There is no statistical basis for concluding that there has been a reduction in the market risk premium in recent times."*[43]

Finally, Brealey, Myers et al recommend an MRP of 8% for Australia.[44]

5.4 Conclusion

KPMG considers that the value of the MRP should be estimated by reference to the long term historical average Australian MRP. The evidence reviewed in this report indicates that there is strong support for an MRP in the range of 6% to 8%.

[43] Gray, S (2001), Issues in Cost of Capital Estimation, downloadable at http://www.esc.vic.gov.au/PDF/2001/SubUQBS_GasPosPapOct01.pdf.

[44] Brealey, R, Myers, S, Partington, G, Robinson, D (2000), Principles of Corporate Finance, 1st Australian Edition, McGraw-Hill, Australia, p. 166.

6 Beta

6.1 Introduction

KPMG's estimate of the pre-tax real WACC for Alinta's gas distribution system is based on the CAPM framework. Under this model, the risk component of the return on capital is a function of the equity beta and the MRP. The equity beta reflects the contribution of an individual investment to the risk of an investor's portfolio and, in the context of the CAPM, all investors will hold some combination of the risk free asset and the risky market portfolio. Consequently, beta captures the contribution of a risky asset to the risk of the market portfolio. Assets are priced in accordance with this contribution, referred to as beta, which is a subset of the total risk of an asset. The diversifiable component of an asset's total risk is not part of the pricing of the asset in the assumed world of the CAPM.

The beta reflects the extent to which possible future returns are expected to co-vary with the overall market return. A beta of 1 means the asset has the same risk as the market whereas a low risk asset will have a beta less than one and display less systematic response to market-wide events than will the average asset. This construct provides the intuition behind thinking about the risk of an asset and behind the use of regression techniques to estimate beta based on events that have occurred.

While not a lot is known about the underlying determinants of beta, it is argued to be a function of the underlying cyclicality of an asset's revenue stream, operating leverage and financial leverage[45]. That is, the equity beta can be viewed as a function of a beta of revenue magnified by operating leverage to the beta of assets (as it is observable) and magnified again by financial leverage to the beta of equity (as it is also observable).

Both the rationale underpinning the estimation techniques and the underlying determinants of beta guide the selection of a beta of equity for gas distribution assets from empirical estimates.

6.2 Estimation method

6.2.1 Background

Betas are usually estimated statistically by regressing historical share market returns against a market index. There are a number of services that provide such estimates including the Risk Measurement Service of the Centre for Research in Finance at the Australian Graduate

[45] Operating leverage reflects the proportion of fixed operating costs to total operating costs. The higher is this proportion, the greater is the variability (and covariability) of an EBIT stream relative to an underlying revenue stream. It is analogous to financial leverage which reflects the proportion of fixed interest costs in determining a net income stream. The higher is this fixed interest cost, the higher is the variability of the net income stream for a given variability in the underlying EBIT stream.

School of Management's ("AGSM") Centre for Research in Finance ("CRIF"), London Business School, Bloomberg, DataStream, and Value Line. These services provide a guide to the beta to be used for assessing a return on equity component of the overall WACC. A key point is that the empirical regressions are a *guide* rather than a definitive estimate. The reasons for this include:

- The CAPM, hence beta, does not fully explain the historical returns on financial assets. As a consequence, the estimation of beta involves a degree of careful judgment.

- The underlying market portfolio is not easily identified. A stock market index is generally used as a proxy. Theoretically the index should be a market value weighted index of *all* assets (i.e. the broadest index possible). Some stock market indexes are market value weighted, others are equally weighted but none contain all assets.

- Investors invest across borders so there is a challenge in selecting the "best" market index. The use of a domestic market index, although inexact, is commonly adopted by market practitioners and regulators.

- The beta estimates (derived from regression analysis) are historical estimates even though the CAPM is forward looking. Therefore there is an assumption of stability in betas across at least the estimation period and the period for which it is used. The selection of an estimation period is a trade off between:

  - being long enough to obtain enough observations to minimise the standard error of the estimate; and

  - minimising an error in the estimate due to changes in the underlying determinants of beta.

  The measurement period varies across risk measurement services. For instance, the CRIF at AGSM uses 48 monthly observations and the default for Bloomberg's is 60 monthly observations. Beta estimates derived from these different sources can differ due to the time period selected.

- Comparables are used as a guide if the business under examination is not listed or there is too much estimation error to rely solely on the beta estimate for only one listed business. Unfortunately, listed pure play comparables are few and far between, particularly in Australia and for gas distribution. Often, comparables from other countries are used as a guide in order to present an expanded data set for consideration. However, interpretation of overseas data presents additional challenges because different tax regimes can influence financial leverage and different mixes of industries and sectors can mean betas relative to the home country index would not be the same as those relative to an Australian index. The Australian economy is quite unusual in that it is very heavily influenced by the resources sector. Thus translating betas from other countries to Australia requires careful judgment.

- The difference in economies has led Gray and ABN Amro to recommend adjusting overseas betas when translating them to an Australian context. Gray recommends that US and UK estimates be divided by 0.72 and 0.88 respectively whereas ABN Amro recommends 0.88 and 0.97[46].

- Financial leverage can vary across industries, countries and firms. Since the equity beta is influenced by the degree of financial leverage in a firm, it is common to de-lever comparable betas to arrive at an "asset" beta then to re-lever at the target financial leverage considered appropriate for the business in question. However, there are a number of available formula for doing so, which adds a further layer of complexity.

- Estimation error is high. Thus confidence intervals around beta estimates are quite wide and many betas will be insignificantly different from 1. In addition, betas vary over time and often, significantly so. Further evidence on this is presented at section 6.3.1.

- Beta estimation is subject to error due to thin trading. Market-wide events are not translated into observable effects on share prices until a trade occurs. Consequently the impact is observed at different times for companies that trade at different points in time. This induces autocorrelation in the market index and a bias for both 'thickly' and 'thinly' traded shares.

The key point is that beta estimates are just that. They assist in informing the process, but caution and judgment must be combined with the estimates to arrive at a beta of equity to determine the required rate of return for investors in gas distribution assets. Our estimate of the appropriate beta for Alinta's gas distribution system is the outcome of a number of processes guided by theory, evidence and practice.

The need for caution and judgment in estimating the cost of capital and the inputs has been recognised by the QCA which has stated:[47]

> *"[The] rate of return should reflect discretion and judgment based on realistic, commercial experience and understanding."*[48]

The QCA is consistent with the PC in recognising that it is better to be conservative than aggressive in setting the cost of capital:

> *"However, the Authority considers that in applying CAPM in a regulatory setting, regard must be had to the risks of allowing too low a rate of return in the sense that considerably more social harm could be caused by selecting too low a rate of return (leading to no investment in the network) than one that is in the upper bound of a reasonable range."*

[46] ABN Amro (1999) p. 3; op cit and Stephen Gray, "Response to Consultation Paper No. 4: Cost of Capital Financing", 4 June 1999, p. 14.
[47] Working Paper 4, p. 41, in the context of recognising adjusted rather than raw betas.
[48] Draft Decision, Chapter 15, page 194.

In some recent regulatory decisions the ACCC has argued that empirical analysis undertaken by the Allen Consulting Group ("Allens") indicated that the appropriate equity beta for regulated gas networks, based upon current observations of equity betas of comparable Australian companies (as the primary source of evidence), and to a lesser extent overseas companies, and re-levered for the regulatory standard gearing level of 60%, is around 0.70. By allowing an equity beta of 1.0 in recent decisions, the ACCC has therefore noted that it is adopting a conservative approach in light of the current market evidence.

The ACCC's characterisation of its approach as conservative or generous presumes some precision in the methodology and data used by Allens in estimating the equity beta. We note that in its report, Allens has refrained from making such a presumption. In particular, Allens states that whilst the evidence suggests an equity beta of 0.70 is appropriate, a revision downwards from the regulatory precedent of 1.0 may not be appropriate because "_it cannot be concluded definitively that this quality of evidence exists at this time._"[49] The report goes on to cite two major concerns with the data:

- first, the primary source of information is derived from listed Australian entities that comprises a group of only four firms, and of these, "_only two of the firms have been in existence long enough to permit the AGSM's-preferred four years of observations to be used, with the beta estimate of one of these – the Australian Pipeline Trust – being based upon only 21 observations…";_ and

- second, Allens expressed concern over the uncharacteristically low levels of the re-levered equity betas for the US firms compared with past estimates. Allens note that it could be possible that stock prices in the US have been affected by recent events.

In forming our view on an appropriate beta for Alinta's gas distribution system, KPMG has considered market evidence on betas for Australian, UK and US comparables. This information is discussed in section 6.3.2.

6.3 Beta estimates

6.3.1 Analysis of recent regulatory decisions

According to CAPM theory, observed equity betas of companies are affected by the target level of gearing of a business. For this reason, it is often useful to conduct comparisons on the basis of a company's asset beta, which is derived by de-levering (i.e. stripping out the gearing component) the observed equity beta of the company. There are various "de-levering formulas" available to achieve this (refer Table 6 below). Some of these formulae also assume positive value for the debt beta, and others purport to take into account the value of imputation tax credits.

[49] Allen Consulting Group, "Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities", July 2002, page 42.

Table 6: Some alternative formulas for unlevering equity beta

Description	Formula
Equation 1: Simple formula	$\beta e = \beta a + (\beta a - \beta d)\ D/E$
Assumes active debt management policy, non-zero debt beta	OR
Credited to Brealey & Myers, "Principles of Corporate Finance", Fifth Edition	$\beta a = \beta e\ E/V + \beta d\ D/V$
Equation 2: Hamada formula	$\beta e = \beta a + (\beta a - \beta d)\ (1\text{-}T)\ D/E$
Assumes passive debt management, non-zero debt beta	
Equation 3: Appleyard and Strong, Non-zero debt beta	$\beta e = \beta a + (\beta a - \beta d)\ \{1\text{-}\ T[kd\ /\ (1\text{+}Kd)]\}\ D/E$
Equation 4: Monkhouse formula	$\beta e = \beta a + (\beta a - \beta d)\ \{1\text{-}\ Te[kd\ /\ (1\text{+}Kd)]\}\ D/E$
Modified version of equation 3, by replacing T with an effective corporate tax rate (Te) that is defined as: Imputation credits payout ratio X imputation credits utilisation rate X Statutory corporate tax rate	

Notes:
*"Active" debt management refers to a debt management policy where the dollar value of debt is assumed to change each in such a way that the ratio of debt to enterprise value remains constant. "Passive" debt management refers to a debt management policy where the dollar value of debt is assumed to be fixed and held constant, with payments made on a predetermined basis. The WACC formula effectively assumes an **active** debt management policy.*

Table 7 and Table 8 below provide a summary of betas and de-levering formulas assumed during recent regulatory reviews of gas and electricity distribution pricing. The information displayed below indicates that an equity beta around 1.0 has been adopted in a large number of regulatory decisions. In some cases, this has resulted from reliance placed on equity betas in other regulatory decisions, whilst in other cases, the equity beta value has been estimated from empirical analysis of implied asset and debt betas, and applying the de-levering formula.

Table 7: Beta values determined at recent gas network access arrangement reviews

Gas decision	Equity beta	Asset beta	Debt beta	De-levering formula
Moomba Sydney (2003)	1.00	Not reported	Not reported	Not reported
DBNGP (2003)	1.20	0.60	0.20	Simple
NT Gas (2002)	1.02	0.50	0.15	Monkhouse
GasNet (2002)	0.98	0.50	0.18	Monkhouse
Victorian Gas Distributors (2002)	1.00	0.40 – 0.54	0.00-0.23	Monkhouse
Average	**1.04**	**0.52**	**0.16**	

Table 8: Beta values at recent electricity network regulatory reviews

Electricity decision	Equity beta	Asset beta	Debt beta	De-levering formula
SPI PowerNet (2002)	1.00	0.40	0.00	Monkhouse
ElectraNet (2002)	1.00	0.40	0.00	Monkhouse
Envestra (2001)	1.10	0.50	0.12	Not reported
Powerlink (2001)	1.00	0.40	0.00	Monkhouse
Average	**1.00**	**0.425**	**0.03**	

It is also evident that regulators do not appear to have come to a landing on whether a zero or positive value should be adopted for the debt beta. The ACCC, for example, appears inclined towards positive debt betas in its gas decisions and zero values for debt betas in electricity decisions, with no justification given for this apparent difference in assumed values. In addition, some regulators adopt a "reverse-engineering" approach to estimating the debt beta using the CAPM formula whilst others have elected to adopt more complicated approaches. For example, the ESC in Victoria estimates the debt beta value by deducting the cost of the embedded default margin and an illiquidity premium from the cost of debt, prior to reverse-engineering the CAPM.

Ultimately however, the precise value of the debt beta does not distort the calculation of the resulting equity beta provided that the debt beta used for de-levering observed equity betas is also used when re-levering asset betas for the target level of gearing.

6.3.2 Market evidence

As noted above, it is conventional practice to estimate an appropriate beta having regard to recent empirical evidence on the betas of comparable publicly listed companies. We have identified a selection of publicly listed companies in Australia, the USA and UK with activities that are comparable with the activities undertaken by Alinta's gas distribution system. Given that perfect comparability is impossible to achieve, inter-company comparisons will only provide guidance on the appropriate beta for a business.

We are also aware of the questions that exist in relation to the appropriateness of relying upon overseas betas and the issues associated with translating them into a "domestic" beta. Notwithstanding this, we consider that overseas evidence on beta may be useful as a secondary source of information in the analysis.

Table 9: Comparable company beta analysis

Company	Gearing	Equity beta	Asset beta Min	Asset beta Max
AlintaGas	35%	0.20	0.13	0.20
Australian Gas Light	33%	0.06	0.04	0.11
Australian Pipeline Trust	53%	0.77	0.36	0.47
Envestra Limited	79%	0.34	0.07	0.23
Energy South Inc	43%	0.24	0.14	0.22
Northwest Natural Gas	43%	0.35	0.20	0.29
Peoples Energy Corp	44%	0.54	0.30	0.39
Cascade Natural Gas Corp	42%	0.52	0.30	0.39
Laclede Group Inc	48%	0.58	0.30	0.40
Nicor Inc	29%	1.25	0.88	0.94
AGL Resources	44%	0.54	0.30	0.39
Atmost Energy Corp	49%	0.48	0.25	0.34
El Paso Corp	48%	2.32	1.20	1.30
NUI Corp	61%	0.05	0.02	0.14
Piedmont Natural Gas	33%	0.52	0.35	0.41
Southwest Gas Corp	59%	0.47	0.19	0.31
Southern Union Co	56%	0.80	0.35	0.46
WGL Holdings	38%	0.48	0.30	0.37
New Jersey Resources Corp	35%	0.32	0.21	0.28
RGC Resources Inc	52%	0.10	0.05	0.15
Northern Border Partners –LP	44%	0.30	0.17	0.26
Cheasapeake Utilities Corp	46%	0.10	0.05	0.15
Sempra Energy	48%	0.56	0.29	0.39
NiSource Inc	60%	0.64	0.26	0.38
Semco Energy Inc	71%	1.01	0.29	0.43
Williams Co Inc	60%	1.88	0.75	0.87
Enbridge Inc	48%	0.27	0.14	0.24
Transcanada Pipelines	45%	0.29	0.16	0.25
Pacific Northern Gas	62%	0.45	0.17	0.30
Terasen Inc	62%	0.22	0.08	0.21
National Grid Transco PLC	52%	0.50	0.24	0.34
Scottish & Southern Energy	20%	0.35	0.28	0.32
Viridian Group PLC	45%	0.20	0.11	0.20
Range			**0.02 – 1.20**	**0.11-1.30**
Average			**0.27**	**0.37**

Notes:

1 Equity betas represent raw equity betas sourced from Bloomberg, except for Australian equity betas which have been sourced from the March 2003 AGSM Risk Measurement Service.

2 The asset beta is obtained using the formula: $\beta a = (\beta e*E/V+ \beta d*D/V)$. In applying this formula, we have calculated a range of values for the asset beta based on a zero debt beta and a debt beta of 0.20. The "min" values shown are consistent with a zero debt beta assumption and the "max" values shown are consistent with a debt beta of 0.20.

3 Gearing is calculated as an average of the gearing levels for the most recent two years for which reported data is available.

The comparable company analysis above indicates that the asset betas for gas transportation businesses falls within a range of 0.02 to 1.30[50]. Clearly, the most striking feature of the data in Table 9 above is the extent of variation in the observed equity betas and de-levered asset betas. This characteristic of the empirical data makes it difficult to comfortably form a view on what might be an appropriate asset and equity beta for Alinta's gas distribution system.

Empirical measurements of beta are also intrinsically volatile over time. Table 10 below, for example, sets out the betas of the four Australian publicly listed comparable companies[51] commonly included in the analysis of proxy betas, and highlights the extent of the instability of the data over time. The betas have been derived from the AGSM Risk Measurement Service as reported over the past four quarters. The figures shown in parentheses indicate the high-low ranges provided by the AGSM.

Table 10: AGSM equity betas

		Equity beta estimates measured over the 48 months ended			
Company	**Code**	**June 2002**	**Sep 2002**	**Dec 2002**	**Mar 2003**
AlintaGas (see note)	ALN	0.10	0.13	0.15	0.20
		(-0.37 to 0.58)	(-0.27 to 0.53)	(-0.23 to 0.54)	(-0.14 to 0.54)
Australian Gas Light	AGL	0.36	0.09	0.08	0.06
		(0.03 to 0.69)	(-0.21 to 0.40)	(-0.24 to 0.40)	(-0.24 to 0.36)
United Energy	UEL	0.25	0.18	0.25	0.08
		(-0.19 to 0.70)	(-0.29 to 0.65)	(-0.23 to 0.73)	(-0.37 to 0.53)
Envestra	ENV	0.59	0.31	0.33	0.34
		(0.32 to 0.86)	0.04 to 0.57)	(0.05 to 0.60)	(0.10 to 0.58)
Australian Pipeline Trust	APT	1.30	0.94	0.79	0.77
		(0.26 to 2.33)	(0.28 to 1.61)	(0.08 to 1.50)	(0.16 to 1.37)

Source: AGSM Risk Measurement Service, June 2002, September 2002, December 2002 and March 2003
Note: Betas quoted for APT are thin-trading adjusted betas. This was indicated as being appropriate under the AGSM calculations.
Note: AlintaGas equity betas are based on less than 48 months of data and therefore, should be interpreted with some caution. For example, the June 2002 equity beta is based on only 20 observations of monthly returns, which represents the minimum number of data points required by AGSM.

Due to the high degree of variation in beta estimates, some regulators have recognised that whilst in principle, it is appropriate to reflect recent market evidence in beta estimates, there are problems with the practice of relying solely upon such evidence for the purpose of estimating beta, particularly given that the information is used to set the cost of capital for the regulated business that will not be revisited for five years. For these reasons, recent decisions by the ACCC and Victoria's ESC have tended to place greater weight on betas adopted in other regulatory decisions, and have put correspondingly less weight on recent market evidence. This has resulted in equity betas defaulting towards a value of 1.0.

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[50] There is strong evidence that betas are less stable for individual securities than they are for portfolios of securities. For this reason, it is preferable to estimate the beta of a company by examining the beta of a portfolio of companies operating in the same business, rather than relying solely on the beta of one company.

[51] The data we used for United Energy was before its recent ownership change which led to its delisting.

6.4 Systematic risk of gas distribution compared to a diversified portfolio

Given the tendency of Australian regulators to adopt equity beta values of around 1.0 for regulated networks, it is worth examining the relative level of systematic risk implied by an equity beta of 1.0 (at a gearing of 60% debt to total assets), with reference to the average level of systematic risk across the entire market (that is, an equity beta of 1.0 at the market average level of gearing).

As noted in Section 6.1 above, the equity beta is a function of:

- the undiversifiable (systematic) risk of the asset; and
- the level of debt (gearing) employed in the financing of the asset.

Consequently, when deriving estimates of the proxy equity beta from market data, or when comparing the equity beta values of two different firms, it is essential that appropriate adjustments be made for any differences in the levels of gearing employed by different firms.

Notwithstanding these fundamental principles of the CAPM, some stakeholders - including regulators - occasionally make invalid comparisons between the equity betas estimated for regulated companies, and the equity beta of the market as a whole. For instance, page 83 of the ACCC's Draft Decision on the Tasmanian Electricity Revenue Cap (September 2003) states:

> *"The ACCC has used an equity beta of one [and a gearing assumption of 60% debt to total assets] in its previous revenue cap decisions, suggesting that the Transmission Network Service Providers face the same volatility as the market. However, there is a view that gas and electricity transmission businesses are less risky as their earnings are more stable than the market portfolio - suggesting an equity beta of less than one."*

As already noted:

- It is invalid to directly compare the equity beta of a 60% geared entity with the market average equity beta of 1.0, because the average level of gearing employed in the market is likely to be substantially less than 60% debt to total assets.
- It is necessary to make adjustments for different gearing levels before making any direct comparisons of equity betas.

A valid basis on which to make such comparisons is to compute asset (ungeared) betas. This approach was adopted by the ESC (then Victorian Office of the Regulator-General) in its 1998 Gas Access Arrangements Review.[52] The ESC's 1998 analysis found that:

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52 Office of the Regulator-General, Victoria, *Staff Paper Number 1: Weighted Average Cost of Capital for Revenue Determination - Gas Distribution*, 28 May 1998, page 66. A copy of the document is available at: http://www.esc.vic.gov.au/docs/Gas/wac98519.pdf

- the average level of gearing employed by a sample of 47 of Australia's top 100 listed companies was around 33% debt to total assets;
- this implied an average asset beta for the sample of around 0.7; and
- applying a gearing assumption of 60% debt to total assets to the sample produced an estimated equity beta of around 1.6.

In a more recent study, NECG estimated that an average asset beta of listed firms on the Australian Stock Exchange is around 0.64.[53] The conclusions of the analysis completed more recently by NECG are consistent with those of the Victorian regulator's 1998 work. Both analyses demonstrate clearly that an equity beta of 1.0 (at an assumed gearing of 60% debt to total assets) represents a level of systematic risk that is ***materially below*** the average level of systematic risk of the market, taking into account the average level of gearing employed in the market.

Given these considerations, we consider that an equity beta value of *no less than* 1.0 (at the benchmark gearing level of 60% debt to total assets) represents a fair and reasonable allowance for the systematic risk attributable to gas distribution. Given the views already adopted in a number of other regulatory decisions in Australia, we propose adopting an equity beta value of 1.0.

6.5 Conclusion

Having regard to the market evidence on betas that we have reviewed, our concerns as to the stability or robustness of the data, and our awareness that the WACC for Alinta's gas distribution system will apply for a five year regulatory period, KPMG considers that under current circumstances, it is reasonable to adopt an equity beta of **1.00**[54] for the purpose of estimating an appropriate WACC. This approach is consistent with the approach currently adopted by the ACCC and the ESC in Victoria.

Using the simple de-levering formula, and assuming a debt beta in the range of 0.0 to 0.20 and a gearing level of 60%, an equity beta of 1.0 would correspond with an asset beta in the range of 0.40 (zero debt beta) to 0.52 (debt beta of 0.20).

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53 NECG, *2003 Review of the Draft Statement of Principles for the Regulation of Transmission Revenues: Submission to the ACCC for the Electricity TNSPs,* November 2003, page 5. A copy of the document is available at: http://www.accc.gov.au/content/item.phtml?itemId=419802&nodeId=file4005f8eccb970&fn=NECG%20Submission%20on%20behalf%20of%20TNSP's.pdf

54 Estimated using the 'simple' formula.

7 Gearing

In selecting an appropriate capital structure for the purposes of estimating the WACC, it is often instructive to examine the observed gearing levels of other businesses operating in the same industry.

In Australia, an assumed gearing level of 60% has emerged as the industry norm for regulated gas and electricity network businesses, as shown in Table 11 below.

Table 11: Gearing values adopted in recent gas and electricity determinations

Decision	Gearing (D/V)
Moomba Sydney (2003)	60%
DBNGP (2003)	60%
NT Gas (2002)	60%
GasNet (2002)	60%
Victorian Gas Distributors (2002)	60%
SPI PowerNet (2002)	60%
ElectraNet (2002)	60%
Envestra (2001)	60%
Powerlink (2001)	60%

As shown in Table 12 below the empirical evidence that we have reviewed suggests that the regulatory benchmark capital structure of 60% debt to total assets is reasonably consistent with market practice.

Table 12: Observed gearing (defined as year end debt to total enterprise value) levels of comparable companies

Company	2000	2001	2002	2003	Average
Australian Gas Light	37%	46%	40%	29%	**38%**
Australian Pipeline Trust	56%	54%	56%	50%	**54%**
AlintaGas	45%	38%	32%		**38%**
GasNet		67%	66%		**67%**
Envestra Limited	82%	78%	78%	72%	**78%**
Average	**55%**	**57%**	**54%**	**50%**	**55%**

Source: Aspect Financial Ratio Analysis, Annual Ratio Analysis; KPMG analysis

On the basis of the above evidence, KPMG has adopted a benchmark capital structure of **60%** for the purpose of estimating an appropriate WACC for Alinta's gas distribution system. KPMG also understands that a 60% gearing level has been adopted as a fixed principle under clause 38(1)(c) of Alinta's Access Arrangements. As such, the ERA is obliged to adopt a 60% gearing level for the purposes of determining an appropriate WACC.

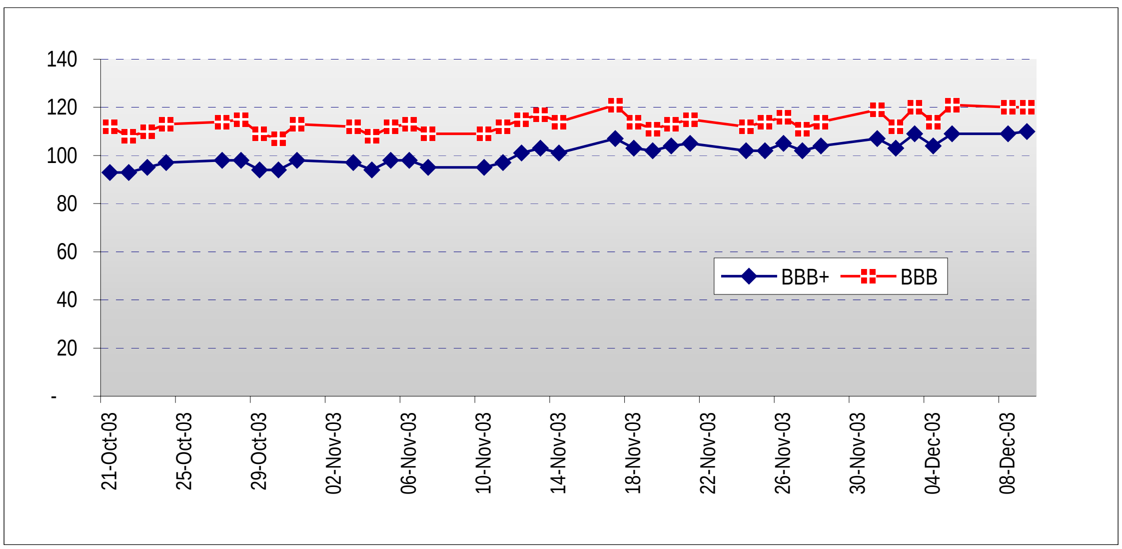
8 Debt margin

The cost of debt represents the cost of borrowing, which is based on the credit worthiness of the borrower. In estimating the debt margin, regulators have assumed that regulated businesses would seek to target an investment grade credit rating (i.e. BBB- or better) [55].

In estimating the debt margin for the purpose of estimating an appropriate WACC for Alinta's gas distribution system, KPMG has referred to the generic debt margin estimates for debt securities of 10 year maturity from CBA Spectrum, an online resource provided by the Commonwealth Bank. CBA Spectrum provides information on the pricing of various rated nominal bonds issued in the Australian capital market. For example, it is possible to obtain the pricing of bonds with a BBB or BBB+ credit rating, and from this, determine the implied margin at various dates.

The chart below illustrates the debt margin on BBB and BBB+ rated bonds based on data obtained from CBA Spectrum over the 20 days to 9 December 2003.

Figure 1: CBA Spectrum debt margins for BBB+ and BBB rated bonds



The data suggests that the debt margin for BBB+ rated bonds averaged over the 20 days to 9 December 2003 was **105 basis points**, and for BBB rated bonds, **116 basis points**.

Because many corporations seek to borrow from the nominal debt market and use CPI swaps to hedge the CPI component of the nominal cost of debt, it is appropriate to add in an

[55] The validity of this assumption is cross-checked in regulatory decisions by forecasting the projected cash flows implied by the decision, and computing various required financial ratios.

allowance for the cost of CPI swap hedging costs. An allowance of **20 to 50 basis points** has been estimated as being appropriate[56].

A second additional allowance relates to debt establishment costs. This represents the transaction costs associated with raising debt capital and is paid to the bank or financial institution arranging such debt. Such costs do vary with each transaction, however an indicative allowance is 10 to 20 basis points. We are aware that in the ACCC's recent regulatory decision on GasNet, an allowance of **12.5** was regarded as being appropriate for debt raising costs.

Adding these components together we consider that a debt margin in the range of **1.4% to 1.8%** is appropriate for Alinta's gas distribution system, given a gearing level of 60%. This estimate is consistent with debt margins adopted in recent regulatory decisions on gas networks as set out in Table 13 below.

Table 13: Debt margins adopted in comparable decisions

Decision	Regulator & Date	Debt margin
NT Gas	ACCC, Dec 2002	1.54%
GasNet	ACCC, Dec 2002	1.585%
Victorian Gas Distribution	ESC, Oct 2002	1.74%
Queensland Gas Distribution	QCA, Oct 2001	1.55%
Moomba-Adelaide Pipeline	ACCC, Sep 2001	1.2%

Sources:

ACCC Final decision, Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin pipeline, 4 December 2002, page 83; ACCC, Final decision, GasNet Australia, Access Arrangements Revision for the Principal Transmission System, 13 November 2002, page 95; Essential Services Commission, Review of Gas Access Arrangements, Final Decision, October 2002, page 362; Queensland Competition Authority, Final Decision, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited, October 2001, page 222; ACCC Final Decision, Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System, 12 September 2001, page 40.

On the basis of the above, we thus consider that a debt margin in the range of **1.4% to 1.8%** to be the debt margin for the purpose of estimating an appropriate WACC.

The resulting pre-tax cost of debt would therefore fall within a range of **7.3% to 7.7%**.

[56] Refer page 125 of Citipower's submission to the ESC which is available at http://www.esc.vic.gov.au/apps/page/user/pdf/citicht4.pdf

9 Corporate tax rate

Under the conventional approach for determining WACC, the appropriate tax rate to assume is the cash or effective rate of company tax. This assumption recognises the fact that the existence of tax concessions such as accelerated tax depreciation may cause the actual tax payable by a company in a particular year (the "cash tax") to vary from the statutory corporate tax rate.

Whilst it is acknowledged that theory requires the use of a long run effective corporate tax rate, the difficulty of accurately estimating the effective tax rate over long time frames has generally been acknowledged by academics and practitioners.

For the purpose of revenue determination, we consider that the appropriate tax rate to adopt is the statutory corporate tax rate. Notwithstanding that differences between taxable profit and accounting profit will invariably result in the cash tax rate in any given year being more or less than the statutory corporate tax rate, when considered over the life of the assets, the cash tax rate is likely to approximate the corporate tax rate. Given that the underlying gas distribution assets owned by Alinta are long-lived assets, we consider that it is appropriate to adopt the current corporate tax rate of 30% in determining WACC. We note that IPART has recently adopted the statutory corporate tax rate as the applicable tax rate for the purpose of calculating a pre-tax real WACC in its current review of electricity distribution prices in NSW.

10 Value of imputation credits

10.1 Introduction

Under Australia's dividend imputation system, domestic equity investors receive a taxation credit (i.e. a franking credit) which is attached to any dividends paid out of after-tax company returns. This franking credit, which reflects the amount of tax that has been paid by the company on each dollar of dividend, may be used to offset the personal tax of the investor, and hence, represents additional cash flow to the investor after-company and personal tax. Without the franking rebate, shareholders would, in effect be paying personal tax on profits that had already been subject to company tax. In a sense, therefore, franking credits effectively represent personal tax collected or withheld at the company level.

In the modified CAPM formula, the value attributed by an investor to imputation credits is represented by "gamma" and denoted by γ. Officer, who effectively re-cast the textbook cost of capital formulation into one that accommodates an imputation tax system, describes the notion of γ in the following way:

> *"… γ is the proportion of tax collected from the company which gives rise to the tax credit associated with a franked dividend. This franking credit can be utilised as tax credit against the personal tax liabilities of the shareholder. γ can be interpreted as the value of a dollar of tax credit to the shareholder."*[57]

In a footnote to the above statement, Officer provides some additional explanation of γ:

> *"For example, if the shareholder can fully utilise the imputation tax credits then ("value") γ = 1, e.g. a superfund or an Australian resident personal taxpayer. On the other hand a tax exempt or an offshore taxpayer who cannot utilize or otherwise access the value in the tax credit will set γ = 0. Where there is a market for tax credits one could use the market price to estimate the value of γ for the marginal shareholder, i.e. the shareholder who implicitly sets the price of the shares and the price of γ and the company's cost of capital at the margin, but where there is only a covert market, estimates can only be made through dividend drop-off rates…"*

It is clear then that different investors will attach a different value to γ, depending on whether they can access the value of imputation tax credits. Most firms, particularly large firms, will have an investor base that typically comprises a mix of investors, some of whom would be able to access the value of credits, and some of whom would not.

[57] Officer, R. R., 1994, The Cost of Capital under an imputation tax system, Accounting and Finance, May, pp 1-17, page 4.

10.2 Gamma estimates

10.2.1 Empirical studies

The table below summarises the various estimates of γ that have been derived from empirical studies. All of these studies use data from Australian-based companies, to create a sample that is representative of the Australian market.

Table 14: Empirical estimates of the value of imputation credits

Study	Methodology	Estimated value of γ
Hathaway & Officer (1992)	Dividend drop-off	58% - 82%
Brown & Clarke (1993)	Dividend drop-off	72%
Bruckner, Dews and White (1994)	Dividend drop-off	33.5% - 68.5%
Hathaway & Officer (1999)	Analysis of tax statistics	48%
	Dividend drop-off	49% (large co.) 44% (all companies)
Walker & Partington (1999)	Dividend drop-off	88% or 96%
Cannavan, Finn & Gray (2001)	Inference from value of individual share futures and low exercise price options	0%
Chu & Partington (2001)		Close to 100%[58]
Twite & Wood (2002)	Inference from analysis of trading in derivatives	45%

Sources:
Hathaway, N. and R. R. Officer, 1992, The Value of Imputation Tax Credits, Unpublished manuscript, Graduate School of Management, University of Melbourne; Brown, P. and A. Clarke, 1993, The Ex-Dividend day behaviour of Australian share prices before and after dividend imputation, Australian Journal of Management, 18, 1, pp. 1-40; Bruckner, K. N. Dews and D. White, 1994, Capturing value from dividend imputation, McKinsey & Company; Hathaway, N. and R. R. Officer, 1999, The Value of Imputation Tax Credits, Unpublished manuscript, Graduate School of Management, University if Melbourne; Walker, S. and G. Partington, 1999, The Value of Dividends: Evidence from cum-dividend trading in the ex-dividend period, Accounting and Finance, vol 39, p293;Cannavan, D., F. Finn and S. Gray, 2002, The value of imputation tax credits, working paper, University of Queensland and Duke University; Chu, H. and G. Partington, 2001, The market value of dividends: Theory and evidence from a new method, working paper, University of Technology, Sydney, p39; Twite, G. and J. Wood, February 2002, The Pricing of Australian imputation tax credits: Evidence from individual share futures contracts, working paper.

[58] Whilst the results suggest imputation credits are close to fully valued, it should be noted that the standard error of the estimate is 97% which indicates substantial variation around the mean estimate.

10.2.2 Other methodologies

As is evident from the above table, the existing empirical evidence on the likely value of γ is dominated by studies that employ a methodology known as dividend drop-off analysis. Under this methodology, the value of imputation credits is analysed by comparing the cum-dividend share price of a dividend-paying company with its ex-dividend share price. As the difference between these share prices (i.e. the drop-off) theoretically represents the value of the money distributed, any decline in the share price in excess of the cash dividend entitlement is assumed to be attributed to the value of the imputation credit attached to the dividend.

In addition to dividend drop-off analysis, other methodologies that have been employed to estimate the value of imputation credits include:

- analysis of national taxation statistics.

  This technique was used by Hathaway & Officer (1998). The authors determined the ratio of franking credits distributed each year to the amount of company tax paid each year (i.e. the “access rate”) and proportion of franking credits distributed by companies that are actually claimed or redeemed by investors (i.e. utilisation rate) to infer the value of imputation credits. The value of imputation credits is assessed from the product of the access rate and the utilisation rate.

- specially developed equilibrium pricing models.

  Wood (1997) estimates the value of imputation credits by treating Australia as segmented from world markets, using a specially developed equilibrium pricing model.

- comparison of differences in the pricing of certain derivative securities and their underlying shares.

  This is a recent methodology that has been employed by Cannavan, Finn and Gray (2001). They infer the value of imputation credits from the value of individual share futures (“ISF”) and Low Exercise Price Options (“LEPOs”), as compared with the price of the underlying shares.

  The authors consider the methodology used in their study provides a better indication of the value of imputation credits for large companies, as compared with dividend drop-off analysis, since:

  - the analysis of value can be undertaken each time an ISF or LEPO trades within one minute of a trade in the underlying share, and hence accommodates a larger sample size that brings statistical benefits and enables calculation to be done on a company-by-company basis;

- the analysis is not confined to ex-dividend dates, when share price data is often confounded by the activities of short-term arbitrage traders; and

- many dividend drop-off studies suffer from a statistical problem known as multicollinearity which makes it difficult to separate the value of cash dividends from the value of the imputation credits. The authors allege that the important consequence of this work is that the results from many earlier studies on the value of imputation credits employing this technique are highly questionable. In particular, the authors state that:

  "…in contrast to conventional wisdom, for large companies with substantial foreign investment the market value of these tax credits is close to zero after recent changes to tax laws that effectively prevent their transfer."

10.3 Regulators' views

10.3.1 Basis of regulatory views

10.3.1.1 IPART

Up until recently, IPART - unlike its counterparts in other Australian jurisdictions - has adopted a range of 30% to 50% for the value for imputation credits. IPART has considered much of the evidence shown in Table 14 in the past, and concluded that in light of this evidence as well as considerations of foreign versus domestic ownership, a value for imputation credits between 30% and 50% is reasonable.

KPMG is aware that in its recent draft determination on the 2004 NSW electricity distribution price review, IPART has proposed to adopt a point estimate of 50% for imputation credits. We have examined IPART's justification for its decision and believe that the Tribunal has based its decision on erroneous evidence.

We note, in particular, that IPART's decision is based upon the evidence set out in Table A7.23 of the draft determination which is reproduced in Table 15 below.

Table 15: Extract from Table A7.23 of the Draft Determination

Study	Method	Period	Gamma
Cannavan, Finn & Gray	Futures and LEPOs	Futures: 1994-99 LEPOs: 1995-99	Nil
Brucker, Dews & White (1994)	Dividend drop-off	1987-1990	0.335
Twite & Wood (2002)	Derivatives prices	16/05/94 – 31/12/95	0.45
Hathaway & Officer (1999)	Aggregate taxation statistics	1989/90 – 1994/95	0.6
Hathaway & Officer (1999)	Dividend drop-off	1/1/85 – 30/06/95	0.63
Chu & Partington (2001)	Rights issues	01/91 – 12/99	Close to 1

However, our review of the studies quoted in Table 15 has indicated that the values of "gamma" attributed to the Hathaway & Officer (1999) study are incorrect. Based on our review, the correct value based on the aggregate taxation statistics methodology should be 0.48 and the correct value based on the dividend drop-off methodology should be 0.44[59].

KPMG considers that had the correct figures been taken into account, IPART would not have been justified in concluding that the evidence reviewed supported an increase to a point estimate of 50%, particularly given the concerns that IPART noted in relation to the study by Chu & Partington (2001).

10.3.1.2 Other regulators

Regulatory decisions issued by regulators other than IPART to date have taken a more aggressive approach to support a value for γ of 50%. Both the ESC and the ACCC have stressed in various decisions that a value of γ of 50% represents the minimum value that they consider should be attributed to imputation credits, given that previous empirical evidence provides more support for a value above 50% than below it.

10.3.2 The case for and against a higher value for gamma

The case for attributing a higher value for gamma is framed largely around the form of CAPM adopted – whether world equity markets are integrated or segregated - and thereby, the requirement for consistency with the identity of the underlying investor for the purposes of estimating a value for gamma. For example, it has been argued by regulators such as the ACCC and ESC, that it is inconsistent to adopt a value for imputation credits that assumes the presence of foreign investors if a domestic CAPM – which implies world equity markets are segregated - is adopted.

This argument is explained by the ESC, by reference to a submission by Dr Martin Lally, as follows:

> *"… a submission from Dr Lally argued that adopting an assumption for gamma as low as 0.5 implied an assumption that a large portion of the franking credits remain unutilised, which can only reflect an assumption that foreigners have a significant share in the Australian equity market. He commented that this is inconsistent with a domestic version of the CAPM that the Office has adopted, and that the comments received in relation to the treatment of foreign investors argue for the use of an international version of the CAPM."*[60]

The ESC went on to outline Lally's recommendation for the cost of capital to be first calculated assuming complete segregation of markets and then assuming complete integration of markets. To the extent that the results from the two approaches differ, then a value that reflects the strength of one's belief about these two models should be adopted.

[59] Refer Hathaway & Officer (1999), page 3 and Table 2, page 18.

[60] ORG, Final Decision, Electricity distribution price determination 2001-2005, Volume 1, Statement of Purpose and Reasons, page 134.

Lally suggested that in moving from an assumption of complete segregation to complete integration, three changes would be required – gamma, the equity market risk premium and beta. The value of γ would move from around 80%[61] assuming complete segregation of markets to 0% assuming complete integration of markets. The equity market risk premium was likely to be lower but the direction of the change in beta is unclear. Lally suggested it was likely that the outcome could be a lower cost of capital, as was the case in a separate study that he had conducted in relation to New Zealand firms[62].

The arguments put forward by Lally have been extensively analysed by Professor Stephen Gray[63]. Gray acknowledges that in theory, it may be more appropriate to use an international CAPM. Existing empirical research also suggests that the performance of ICAPM models is superior to that of the domestic CAPM. However, due to the complexity of such models, the adoption of such a model would lead to significantly more debate amongst stakeholders about methodologies and interpretation since there are many versions of the international CAPM and some versions require a substantially greater number of inputs.

As a compromise position, Gray suggests that it may be possible to retain the use of a domestic CAPM notwithstanding it is theoretically incorrect, but to calculate an upper bound for the error that is induced by using the 'wrong model'. Using a model proposed by Karolyi and Stulz (2001), Gray estimates this error bound at 5%. This error bound is considered to be of the same order of magnitude as the error that would arise from imprecise estimation of parameters that would normally arise in applying the CAPM. In other words, use of an international CAPM will not produce errors that are any greater than the error that might result from using a purely domestic CAPM.

It is also worth noting that it remains common market practice to assume that imputation credits are not fully valued or not valued at all[64]. Evidence drawn from expert reports on takeovers to support such practices was provided in recent analysis, which showed that of 122 reports reviewed only 48 (or 39%) provided support showing how they had arrived at the WACC used in their reports. Of these, 42 (or 88%) used the classical CAPM model and

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[61] Dr Lally's submission (downloadable at http://www.esc.vic.gov.au/docs/electric/lally.pdf) initially referred to γ moving from 100% (assuming complete segregation) to 0% (assuming complete integration) however, the ORG reported in footnote 636 of the Electricity Distribution Price Determination that Lally's definition of γ needed to be modified to take into account the payout ratio of franking credits. Using Hathaway & Officer's estimate of 80% for the payout ratio, the ORG estimated a value of γ at 80%.

[62] Dr Lally argues that in adopting his preferred approach, the movement from an assumption of complete segregation to an assumption of complete integration leads to changes not only in the value of γ, but also to changes in beta and the market risk premium. In particular, he suggests that the value of γ would fall, the value of beta may fall, and the MRP would fall. The first of these effects would lead to a rise in the cost of capital, whereas the latter two may or would lead to a fall. Dr Lally's own research on New Zealand firms suggests that the net effect of these factors is to lower the cost of capital for these firms.

[63] S. Gray, Issues in Cost of Capital Estimation, 19 October 2001, op cit.

[64] Lonergan does not state which form of CAPM was used in each of the expert reports he reviewed. Based on our experience, however, market practitioners tend to utilise the domestic form of the CAPM. This is evident from their approach to estimating parameters such as the risk free rate, beta and the market risk premium.

made no adjustment for dividend imputation. Only six reports made an adjustment to reflect dividend imputation[65]. Furthermore, of the seven reports (6%) that did attribute value to imputation credits, it appears that five attributed little or zero net effect on the value of the company being assessed."[66]

This study goes on to provide a long list of conceptual grounds cited in reports for not adjusting for imputation credits, including:

- the value of franking credits is dependent on the tax position of each individual shareholder;
- there is no evidence that acquirers of businesses will pay additional value for surplus franking credits;
- there is little evidence that the value effects of dividend imputation are being included in valuations being undertaken by companies and investors or the broader market;
- foreign shareholders are the marginal price-setters of the Australian market yet many such shareholders cannot avail themselves of the benefit of franking credits; and
- there is a lack of certainty about future dividend policies, the timing of taxation and dividend payments and consequently about franking credits.

We note that Lonergan's analysis does not provide any indication of which form of CAPM had been adopted in the expert reports he reviewed, however, the list of conceptual grounds cited for not adjusting for imputation credits (which effectively implies a gamma of zero) did not include "use of an international form of CAPM" as a reason. This suggests that the reports reviewed by Lonergan employed a domestic form of CAPM.

10.3.3 The benchmark investor assumption

We note that there are problems with the definition of the benchmark investor that is used to support the views held by a number of regulators on the value of γ.

To date, the value of γ has been set on the basis that the actual tax residence of the owners of the regulated entity is irrelevant for revenue setting, and that the appropriate benchmark investor should be an "Australian" investor. The ESC has previously suggested that if the actual identity of the owner is used, consistency would require that the tax position, beta and gearing of the actual owner, amongst other things, be reflected in the value of γ. We consider such comments to be unwarranted since they effectively broaden the scope of γ to take into account any other tax concessions available to the investor, that have the effect of reducing or offsetting the corporate tax liability of the regulated business.

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[65] Lonergan, W., Autumn 2001, "The disappearing returns, why dividend imputation has not reduced the cost of capital", JASSA, page 13.
[66] Lonergan, W., Autumn 2001, op cit, page 14.

It is our view that such an argument is flawed, since even in a benchmark 'Australian investor' framework, it could be taken to the same extreme situation where effectively all tax concessions available to an individual investor represents a reduction in what Officer has described as the "pure" corporate tax.[67] We believe that the extension to the scope of γ that is implied by the above statements by the ESC and the ACCC reflects a fundamental misunderstanding of the concept. γ derives its value from the payment of corporate taxes (and hence, generation of imputation credits) by the firm, that will effectively be rebated to the investor. γ cannot possibly capture all other tax concessions available to an investor as there is no relationship between these other tax concessions and the corporate tax paid by the regulated business, as there is between the imputation credit rebate and corporate tax paid.

As for the argument that it would be necessary to take into account the beta and gearing that would be applicable to a foreign investor, we note that information on such parameters drawn from comparable overseas companies are already considered by regulators in assessing an appropriate value for such parameters. We have not previously seen, in their assessment, any adjustments made to adapt such data to an "Australian investor" perspective. In light of this, it is difficult to understand how the parameters would change if a foreign investor assumption were to be adopted.

In theory, the argument regarding the most appropriate benchmark investor assumption is somewhat irrelevant. This is because <u>the CAPM measures the marginal cost of capital or the required rate of return from the perspective of the marginal investor</u>. We have previously highlighted comments from Officer that the marginal investor is the one who implicitly sets the price of shares, the value of γ and the company's cost of capital at the margin.

The broader question of what value to attribute to γ therefore, should be defined as *what proportion of taxes paid at the corporate level is really a pre-collection of the personal tax of the* ***marginal*** *investor*. This definition can be simply stated in theory. However, in practice, determining the identity of the marginal investor can be difficult.

One view that has been expressed by Officer is that the marginal investor – the one who sets the price of Australian stocks - is the foreign investor. The argument is expressed in terms of whether Australia is a price-taker or price-maker in capital markets.

> *"In an open capital market, such as Australia, where the size of the market relative to offshore markets implies it is a price taker, we would not expect the cost of capital to change – the arguments to support this proposition have been made in Officer (1988)."*[68]

Cannavan, Finn and Gray (2001) also support this view:

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[67] Other than γ, the only other cost of capital parameter that could capture the tax concessions available to an investor is in the corporate tax rate. However, it is a well known valuation concept that the relevant cost of capital is that of the target business, not the investor. Hence, the only tax circumstances that are relevant for the corporate tax rate parameter, are those that pertain to the business.

[68] Officer, R.R., 1994, The cost of capital of a company under an imputation tax system, Accounting and Finance, May, pp. 1-17.

> *"As Officer (1988) points out, however, Australia is a small open economy so the cost of capital for Australian companies will be determined by supply and demand conditions in world capital markets. That is, large companies are unlikely to be financed solely by resident investors – at least some non-resident investment is likely to be required…*
>
> *In this case, resident investors will receive capital gains, cash dividends and imputation credits and non-resident investors will receive capital gains and cash dividends only. Since resident investors receive a higher return (via the imputation credits granted by the local tax system), they will the first to invest. The marginal investor will then be a non-resident, who will receive a return in the form of capital gains and cash dividends that just meets their required return…"*

The important consequence of the marginal investor being a non-resident / foreign investor is that the value of γ is likely to be closer to zero than the 50% that is currently being used in regulatory decisions. In Cannavan, Finn and Gray (2001), the authors state that:

> *"…prior to the introduction of the 45-day rule, imputation credits for the average company are valued at around 33 cents in the dollar by the representative investor. This is consistent with Wood's (1995) estimate of 32% from an analysis of listed warrants using a different empirical technique. This is consistent with the representative investor being a foreign investor who can extract some, but not all, value from imputation credits by transferring them to domestic tax-paying investors…*
>
> *… we cannot reject the hypothesis that imputation credits are worthless to the marginal investor after the introduction of the 45 day rule."*

The use of a marginal investor concept for attributing an appropriate value to γ is not only underscored by basic CAPM concepts, but is also dictated to a large extent by the empirical evidence that is available on the likely value of γ. Empirical studies implicitly measure the value of γ from the perspective of the marginal investor in the Australian market because:

- this basis of measurement is evident from the underlying data analysed in each study, which is share price data on Australian companies, all of whom would display a mix of investors on their share register; and

- it is accepted that share prices are set by the marginal investor.

As a result, the measure of γ that emerges from empirical studies of this nature can only represent the value of γ to the marginal investor. To the extent that Australia is a price-taker in world markets, the marginal investor will be a foreign investor.

Importantly, none of these studies focuses on companies that have purely Australian-resident shareholders. To support the view of some regulators that γ should reflect 'average Australian ownership', evidence of the value of γ using data from companies with shares held solely by Australian resident shareholders would be required. We are not aware of any empirical studies on γ which utilise such data. It is therefore not possible for regulators to maintain a 'private Australian ownership' assumption and draw support from available empirical evidence (as provided by the studies listed in Table 14) that measures the value of γ to the marginal investor in the Australian stockmarket, who is most likely a foreign investor[69].

The only alternative that leads to an internally consistent estimate of the cost of capital is to adopt a value of γ that reflects the value of imputation credits to the marginal investor[70].

10.4 Conclusion

Despite additional research in this area, a considerable degree of uncertainty continues to surround the estimation of the appropriate value for γ. It would therefore seem appropriate for the ERA to err on the side of conservatism by adopting a lower rather than higher value for γ.

We do not support the views promulgated by regulators such as the ACCC, that imputation credits are fully valued by the average Australian investor. The value of γ needs to take into the value of distributed and undistributed franking credits. The fact that companies do not distribute 100% of their credits immediately as such credits are generated means that γ cannot be 100%. Undistributed franking credits are likely to have some value, however, this value would depend upon the timing of their distribution. The longer they are retained by the company, the lesser will be their present value to shareholders.

The "average Australian investor" concept that has formed the basis for regulators' assumptions on gamma is a poorly defined concept. Furthermore, it is difficult to support such concepts when the existing empirical evidence on the value of imputation credits reflects the value of imputation credits from the perspective of the marginal investor. This is necessarily the case since empirical studies utilise share price data as the basis for estimating the value of γ and share prices are set by the marginal investor.

The identity of the marginal investor is difficult to determine in practice. However, for many large companies, particularly those with a significant proportion of foreign investors, there is evidence to support the view that the marginal investor is a foreign investor, who is largely unable to extract any value from imputation tax credits. Accordingly, the most defensible value for γ is one that approaches zero, rather than 100%.

To summarise the position on γ from recent developments, KPMG considers that:

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[69] For example, the ACCC states in its final decision on the Moomba to Adelaide Access Arrangement (September 2001) that "*…the Commission's choice of gamma will be a matter of judgement based on available empirical evidence*". (page 42)

[70] Marginal investor concepts are applied by regulators in estimating other WACC parameters (e.g. cost of debt and risk free rate).

- there is no basis for regulators to argue for an increase in the value of γ above the existing upper bound of 50%;
- more recent research demonstrates that there is good reason to question the appropriateness of a value of γ of 50% since it relies upon evidence from studies that suffer from methodological flaws;
- more recent research demonstrates that a value of zero may be more valid assumption for γ than a value of 50%; and
- the use of a domestic CAPM is arguably inconsistent with the assumption underlying the valuation basis for γ, however, the potential errors from this inconsistency is not expected to be improved by adopting the alternative of an ICAPM model.

We expect that a more conclusive view on the value of gamma will only be formed over time, as more research is undertaken in this area. Until this occurs, we consider that it would be appropriate for the ERA to adopt a value for imputation credits within a range of **30% to 50%**.