ALINTAGAS'S THIRD SUBMISSION TO THE REGULATOR ON EPIC ENERGY'S DBNGP ACCESS ARRANGEMENT

INITIAL CAPITAL BASE, WACC, TARIFF AND OTHER ISSUES

Submission dated 17 March 2000

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1. OVERVIEW

AlintaGas's first Submission addressed the need for Epic Energy to provide depreciated actual cost (**"DAC"**) and depreciated optimised replacement cost (**"DORC"**) valuations of the Dampier to Bunbury Natural Gas Pipeline (**"DBNGP"**).

AlintaGas's second Submission concerned the need for the Regulator to require Epic Energy to provide a Reference Service equivalent to the T1 service that Epic Energy currently provides to users[1].

This third Submission is divided into five sections, addressing the following issues:

- the Firm Service is not an appropriate Reference Service;
- initial Capital Base and other capital issues;
- rate of return;
- tariff; and
- other issues.

A summary is provided at the beginning of each section.

[1] For consistency with the National Access Code, in this Submission AlintaGas uses the term "users" to refer to those previously referred to by the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998* as "shippers".

2. THE FIRM SERVICE IS NOT AN APPROPRIATE REFERENCE SERVICE

2.1 Summary of this Section

The Regulator's *Issues Paper to Assist with Submissions on the Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline* dated January 2000 (**"DBNGP Issues Paper"**), identifies issues for consideration in submitting comments on Epic Energy's proposed DBNGP Access Arrangement.

In accordance with specific issues within the DBNGP Issues Paper, AlintaGas submits that Epic Energy's proposed Firm Service:

- will not be sought by a significant part of the market;
- imposes unreasonable and unnecessary constraints on users;
- incorporates terms and conditions that are unreasonable in the context of the DBNGP; and
- allocates risk between Epic Energy and users in a way that is inconsistent with economic efficiency.

To address these concerns, AlintaGas submits that the Regulator should require Epic Energy to:

(a) provide a Reference Service materially equivalent to the existing T1 service; and

(b) if the Regulator considers a second Reference Service for firm capacity is appropriate, modify the proposed Firm Service to ensure it complies with the National Access Code and sets a reasonable balance between Epic Energy's and users' interests.

2.2 The proposed Firm Service could result in AlintaGas's costs doubling

The impact of Epic Energy's proposed Firm Service on AlintaGas would be to nearly double AlintaGas's DBNGP transportation costs.

This cost assessment includes imbalance surcharges but, because of a lack of suitable data, it excludes peak hour surcharges. Even if both peaking and imbalance surcharges are excluded, the amount AlintaGas would pay under Epic Energy's proposed Access Arrangement increases by 24%.

AlintaGas expects that a similar analysis by other users would also show a significant increase in their DBNGP transportation charges under Epic Energy's proposed Access Arrangement. AlintaGas submits that this increase in costs, which will result in higher delivered gas costs to end users, is unacceptable and unnecessary.

AlintaGas submits that the Regulator should consider in detail all aspects of Epic Energy's proposed Firm Service because, whilst a headline tariff of $1.00 and $1.08 per GJ may appear to be reasonable, the proposed Firm Service will impose significant additional costs on users in comparison to the T1 service.

2.3 The T1 service is a fair and reasonable service

Epic Energy currently provides a T1 service to users in accordance with the *Gas Transmission Regulations 1994* (**"GTRs"**), or in accordance with the *Dampier to Bunbury Pipeline Regulations 1998* and the *DBNGP Access Manual* dated 10 March 1998 (**"**the **1998 Regime"**).

The terms and conditions of the T1 service were developed and refined over a 5-year period. The process started in mid 1994 when a committee of the State Government's Energy Implementation Group, assisted by a working group of industry stakeholders, developed the GTRs, which took effect on 1 January 1995.

The GTRs were then refined after significant input and debate at the Gas Transmission Consultation Committee. Representatives on the committee were drawn from the Office of Energy, the DBNGP operator and DBNGP users. The committee, which was chaired by the Coordinator of Energy, held 56 meetings over a period from 28 June 1995 to 29 January 1998. The committee engaged consultants as necessary. A public forum ensured that all interested parties had the opportunity to provide an input to the proposed changes to the T1 service.

The changes recommended by the Gas Transmission Consultation Committee were incorporated into the GTRs via Gazetted amendments on 20 November 1997. The amended GTRs then flowed through into the 1998 Regime. The 1998 Regime is the current transitional third party access regime for the DBNGP.

When Epic Energy purchased the DBNGP, it did so in the full knowledge that the 1998 Regime was in place and T1 service contracts were in operation. Since then, Epic Energy has contracted with a number of users for T1 services. AlintaGas considers it inappropriate for Epic Energy to now propose not to offer a T1-equivalent service.

AlintaGas submits that, largely due to the extensive consultation process involved in its development, the T1 service terms and conditions are fair and reasonable and allocate risk between Epic Energy and users in a manner consistent with economic efficiency.

AlintaGas submits that a T1-equivalent service will be sought by a significant part of the market. AlintaGas requests the Regulator to consider whether a T1-equivalent service should be provided under section 3.3(a) or (b) of the National Access Code.

A T1-equivalent service is likely to be sought by a significant part of the market because it is a service that appropriately balances risk between the user and the Service Provider. Furthermore, those users with "grandfathered" contracts under which Epic Energy is required to provide the T1 service are likely to require from time to time, incremental and replacement capacity. For the commercial and operational continuity and convenience of all parties, those users are likely to seek such incremental and replacement capacity on the same terms and conditions materially the same as their current T1 service.

2.4 While Epic Energy should be permitted to innovate, the T1 service should be a yardstick for assessing any changes

AlintaGas considers one objective of competition policy to be that the operators of pipelines should be permitted and encouraged to innovate in the services they provide to users. AlintaGas therefore does not consider that, in general terms, a Service Provider should be

required to remain only with the services previously offered. However, AlintaGas considers that any innovation should equitably balance the benefits between users and the Service Provider.

AlintaGas submits that the T1 service offered under the GTRs and the 1998 Regime is relevant to the Regulator's consideration of the proposed Access Arrangement, because:

- AlintaGas has demonstrated in its Second Submission that Epic Energy is required to offer a T1-equivalent Reference Service;
- the T1 service – as far as AlintaGas is aware – is utilised by all DBNGP users;
- the T1 service is a well-tested service that has been proven to provide an appropriate base upon which to operate the DBNGP; and
- most existing users have taken the T1 service terms and conditions into account when determining the level of capacity they wish to reserve.

AlintaGas submits that where there has been a well-developed set of access terms and conditions, evolved over a number of years through an industry consultation process to set a reasonable balance of risks and costs between the Service Provider and users, the Regulator, in considering a proposed Reference Service, can properly ask the Service Provider to justify material shifts from the overall balance of risks and costs. A changed service, which shifts a significant additional burden of risks to users, whilst increasing costs and charges compared with the existing more balanced position, is not welcome, is not fair and reasonable and does not satisfy the objectives of competition policy. The proposed Firm Service entails such a shifting of risks and costs.

AlintaGas submits that the T1 service should be the yardstick for any assessment of Epic Energy's proposed Firm Service. If changes from the balance between Epic Energy and users set by the T1 service are proposed, they should be fully justified. It should be ensured that, on balance, any changes do not result in a shift of risk away from Epic Energy to the users and should not provide Epic Energy with the opportunity for windfall gains (whether or not those windfall gains are apparent when examining the headline tariff).

2.5 The proposed Firm Service is unlikely to be sought by a significant part of the market

Section 3.3(a) of the National Access Code requires that Epic Energy must propose at least one Reference Service which is likely to be sought by a significant part of the market. AlintaGas submits that Epic Energy has not done so.

AlintaGas submits that because the terms and conditions of the proposed Firm Service are weighted in favour of Epic Energy through the imposition of unreasonable and unnecessary constraints and charges on users, no significant part of the market is likely to seek access using the proposed Firm Service. Instead, AlintaGas submits it is likely that access to the DBNGP will almost entirely be sought on non-Reference Service terms and conditions. Because Epic Energy's proposed Firm Service is so unattractive and unbalanced, users such as AlintaGas will have to enter into full-scale negotiations. That is, a significant part of the market would actually seek a different service to the proposed Firm Service.

AlintaGas is a substantial participant in the DBNGP gas transportation market, and considers that it would not apply for the proposed Firm Service.

If most or all users seek access to non-Reference Services, both users and Epic Energy will have to devote substantial time and resources to negotiating access terms, and in some cases perhaps to arbitrating access disputes. Section 3.3(a) of the National Access Code is designed to avoid this inefficiency.

2.6 AlintaGas has not endorsed Epic Energy's proposed Firm Service

In section 2.1(a) of the Access Arrangement Information, Epic Energy states that:

> "Firm Service was developed *after consultation* with a number of existing shippers and producers. *It is drawn from the firm service* which was offered under the GTRs and the Transitional Regime." (italics added)

To the extent this implies that AlintaGas – as one of the users consulted – endorsed Epic Energy's proposed Firm Service, either in broad form or in detail, that implication is incorrect. In a discussion with Epic Energy prior to Epic Energy developing its Firm Service, AlintaGas indicated that it was satisfied with the existing T1 service. Epic Energy provided no alternative proposals for consideration. Furthermore, AlintaGas, being satisfied with the T1 service, provided no alternative proposals for consideration by Epic Energy.

AlintaGas also finds it difficult to accept that the Firm Service is "drawn from" the T1 service, because the proposed Firm Service is significantly different and the risks are tilted so heavily in favour of Epic Energy.

2.7 Changes from the T1 service favour Epic Energy

AlintaGas's analysis of Epic Energy's proposed Access Arrangement shows that material changes, in moving from what is a balanced set of terms and conditions associated with the T1 service to Epic Energy's proposed Firm Service, favour Epic Energy to the detriment of users.

Epic Energy has proposed some changes from the T1 service that will benefit users, such as a simplification of the nomination procedures, but these changes are operational in nature. They do not have a material impact on risk or the average transportation cost that users will incur.

The table below highlights some of the major differences between the T1 service and Epic Energy's proposed Firm Service.

Existing T1 Service	**Proposed Firm Service**	**Change / Comment**
The T1 service is an all-inclusive service.	There is to be one Reference Service, called a Firm Service, and a number of ancillary Non-Reference Services.	The change benefits Epic Energy: The Non-Reference Services add costs to the basic headline tariff associated with the Firm Service.
Full-haul capacity encompasses all capacity downstream of compressor station 9.	Full-haul capacity has been divided into 2 Zones: Zone 9 includes the metropolitan area distribution system and ends	The change benefits Epic Energy: The headline price in Zone 10 is 8% higher than the full-haul headline price. 84% of full-haul

Existing T1 Service	Proposed Firm Service	Change / Comment
	at Kwinana Junction. Zone 10 is downstream of Kwinana Junction	demand is forecast to occur in Zone 10.
73% of the headline tariff is a fixed charge.	95% of the headline tariff is a fixed charge.	The change benefits Epic Energy: Epic Energy will receive a guaranteed revenue of 95% of the 100% load factor (headline) tariff whether or not a user utilises its reserved capacity. This is a hidden cost that penalises users supplying markets with a low load factor, such as the small business and residential market. It will reduce the competitive position of users seeking to supply gas to smaller customers with low load factors. It transfers risk from Epic Energy to the users.
Users pay only for new Delivery Points.	All users pay a Delivery Point Charge.	The change benefits Epic Energy: Delivery Point Charges, which are not included in the headline tariff, will add between $0.02 and $0.05 per GJ to AlintaGas's tariff.
Overrun capacity results if a user exceeds its total reserved capacity (across all Delivery Points) on a day.	Overrun capacity results if a user exceeds its reserved capacity at <u>each</u> Delivery Point. Capacity can only be relocated downstream with Epic Energy's written permission.	The change benefits Epic Energy: It restricts a user's flexibility on a day to relocate spare capacity at one Delivery Point to another Delivery Point.
Imbalance limits are ±8% of a user's total reserved capacity. No imbalance penalties currently apply.	Imbalance limits are ±2% of a user's total reserved capacity. A penalty of $15.00 per GJ applies for each GJ in excess of the ±2% imbalance limit. A Park and Loan Non-Reference Service is available to help users maintain imbalances (no details of the Park and Loan service have been provided by Epic Energy).	The change benefits Epic Energy: The tighter imbalance limits will make it virtually impossible for users, especially those supplying gas to the residential market, to maintain a balance on the majority of days. It increases Epic Energy's revenue and ultimately imposes an additional burden on end-gas users.

Existing T1 Service	Proposed Firm Service	Change / Comment
Hourly peaking limits are 120% in summer and 125% in winter, based on a user's total reserved capacity (across all Delivery Points). No peaking penalties currently apply.	Hourly peaking limit is 120% of a user's reserved capacity at each Delivery Point. A penalty of $15.00 per GJ may be applied if demand at a Delivery Point in any hour exceeds the hourly peaking limit.	The change benefits Epic Energy: The application of peaking limits at individual Delivery Points will increase the occasions a user exceeds the proposed limits, regardless of whether there is a real operational impact. It increases Epic Energy's revenue and ultimately imposes an additional burden on end-gas users.

Each of the above major differences represents a change from the balance struck by the T1 service that benefits Epic Energy and thus affects the fairness, operational flexibility and commercial attractiveness of the proposed Firm Service. AlintaGas submits that this is not fair and reasonable, and is not consistent with National Access Code objectives.

AlintaGas requests the Regulator consider the consequence of Epic Energy's proposed Access Arrangement and terms and conditions in light of the Arbitrator's obligations under section 6 of the National Access Code. Section 6.13 and 6.18(e) of the National Access Code indicate one of the functions of the concepts of the "Reference Service" and the "Reference Tariff". Both are benchmarks that guide the Arbitrator in deciding what service a Service Provider must offer to a prospective user, and on what terms and conditions that service will be provided. Another function of the Reference Service is to provide a prospective user with an "off-the-shelf" service that it can seek from the Service Provider without any negotiation.

If the Reference Service intrinsically favours Epic Energy, it disadvantages those prospective users who seek the "off-the-shelf" Reference Service. Furthermore, it disadvantages those prospective users who chose to negotiate or seek arbitration in relation to access, because the Arbitrator will use the Reference Service as a benchmark. If that benchmark is biased towards one side, negotiations and arbitrations will be similarly unbalanced.

3. INITIAL CAPITAL BASE AND OTHER CAPITAL ISSUES

3.1 Summary of this section

In accordance with the DBNGP Issues Paper, AlintaGas submits that:

- Epic Energy's proposed initial Capital Base, being Epic Energy's 1998 purchase price for the DBNGP, adjusted for subsequent expenditure and depreciation does not meet the requirements of the National Access Code; and
- the factors in Section 8.10 of the National Access Code have not been adequately considered.

This section of the Submission addresses these issues, under the following headings:

- the price Epic Energy paid for the DBNGP would have depended on a number of factors, not only the revenue to be earned from users under the National Access Code;
- the proposal that Epic Energy's purchase price forms the initial Capital Base is not consistent with the economic and policy principles underlying the National Access Code;
- Epic Energy's references to it having paid the purchase price in the course of the competitive bid process are irrelevant;
- Epic Energy's interpretation of sections 8.10 and 8.11 of the National Access Code is incorrect;
- Epic Energy's published preferred pipeline valuation methodologies suggest an optimised replacement cost (**"ORC"**) valuation more in the order of $1 billion; and
- AlintaGas estimates that the DAC for the DBNGP is probably less than $1 billion.

In addition, this section of the Submission addresses a number of other issues relating to Epic Energy's proposed treatment of capital issues, namely:

- the proposed depreciation schedule is inappropriate;
- the proposed asset lives are excessive;
- Epic Energy's proposed deferred recovery account is inappropriate; and
- the forecast new capital investment should be scrutinised.

3.2 The price paid for the DBNGP would have depended on a number of factors

AlintaGas submits that the Regulator should presume that, as with the bids in any asset sale process, all bids made for the DBNGP during the DBNGP sale process in 1997/98 (including Epic Energy's):

(a) were subjective valuations made by the individual bidders; and

(b) likely anticipated greater benefits available from the asset than just the earning of a regulated rate of return under the National Access Code from existing users.

The purchase price of $2.407 billion paid by Epic Energy for the DBNGP was presumably the subjective value of the asset to Epic Energy in March 1998. The purchase price would have been only partly dependent on future revenue potential from existing users of the DBNGP. Factors that might have influenced Epic Energy to bid more for the DBNGP than the economic value of future cash flows from existing users include:

- Strategic benefits and growth potential. The DBNGP, being one of the most significant infrastructure assets in Western Australia, is a strategically important asset with strong growth potential and limited downside risk.

  The Australian Infrastructure Fund (**"AIF"**), which is managed by Hastings Fund Management Limited (**"Hastings"**), and is a 4% part owner of the Epic Energy entities and therefore the DBNGP, had a similar opinion. For example, AIF's 1998 Annual Report states:

  > "AIF acquired an interest in the *highly strategic* Dampier-Bunbury Natural Gas Pipeline."
  >
  > "Given the vast gas reserves of the North West Shelf, WA's strong economic growth rate and the number of projects being considered in the energy intensive resources processing industry, Hastings believes this to be the *premier gas transmission asset* in Australia."

  and,

  > "DBNGP is one of the most *rapidly growing infrastructure assets* in Australia and is *strategically important* to the economy of the state of Western Australia." (italics added in all three extracts).

  This view is supported in an Information Memorandum prepared by Hastings and released on 28 May 1998, where it is stated that:

  > "The DBNGP provides AIX[2] investors with access to the *strong growth* expected to occur in the WA market and an *attractive yield from existing contracts* with major users including Alcoa and AlintaGas."

  and,

  > "A stake in the DBNGP is attractive to AIX for several strategic reasons:
  > …
  > - its *downside is protected* by long-term 'take-or-pay' contracts;
  >
  > …
  > - offers *limited competitive threat* due to high capital costs for new entrants and existence of major gas purchase contracts". (italics added)

- Epic Energy may have perceived a lower risk for its investment in the DBNGP whilst anticipating a rate of return for the DBNGP under section 8 of the National Access Code that assumes a higher risk.

[2] Hastings used "AIX" as the abbreviation for the Australian Infrastructure Fund.

- Epic Energy may have expected to benefit from jurisdictional taxation arbitrage – namely the marginal tax benefit that can be obtained through the use of different tax jurisdictions – in its acquisition of the DBNGP.

- Epic Energy may have perceived synergies between the DBNGP and its existing Australian assets.

- Epic Energy may have expected to be able to outperform the benchmarks used to set regulated tariffs.

The view that bidders place a greater value on a pipeline than the initial Capital Base is supported through consideration of the Victorian transmission pipeline assets. These assets had initial Capital Bases determined in accordance with the principles of the National Access Code prior to their sale, yet purchasers were prepared to pay more than two times the initial Capital Base in order to acquire the assets.

In a competitive tender process, each bidder will make its own assessment of what to bid for the asset. Logically, the prices bid by different tenderers will be different, even though those bids are based on the same information. The fact that a vendor selects one bid over the rest, does not necessarily indicate that the successful bidder's assessment of the value of the asset is correct or is a value consistent with sections 8.1 and 8.10 of the National Access Code. For this reason, although a recent sale price is a factor which the Regulator can appropriately consider in setting the initial Capital Base, AlintaGas submits that the National Access Code sets the right balance when it gives primacy to the DAC and DORC valuation methods.

3.3 Use of purchase price as initial Capital Base is inconsistent with the principles underlying the National Access Code

The overview introduction to the National Access Code states that one of the National Access Code's objectives is to establish a framework for third party access to gas pipelines that:

> "…provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users…"

More specifically, section 8.1 of the National Access Code states that a reference tariff should be designed with a view to achieving, amongst others, the following objectives:

> "(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;
>
> (b) replicating the outcome of a competitive market;
>
> …
>
> (d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries ..."

In the context of competition policy reform, the National Access Code attempts to strike a balance between the interests of the Service Provider and all users. AlintaGas submits that:

(a) the efficient cost of providing services does not include an inflated initial Capital Base; and

(b) the National Access Code should not be used to permit Service Providers to bid inflated prices for assets, by allowing the Service Provider to recover the inflated price in the regulated tariff base.

These issues are discussed below.

3.3.1 An inflated initial Capital Base is not an "efficient cost"

The valuation of the initial Capital Base should be similar for any Service Provider, whether that Service Provider is government owned or a private firm. The initial Capital Base determined by the Regulator needs to give the Service Provider the ability to earn revenue from the provision of third party access to an asset which reflects the "efficient cost", including capital cost, of providing that access (see section 8.1(a) of the National Access Code). The "efficient cost", by definition, does not include an inflated Capital Base, or a Capital Base that is set by reference to a price that includes other strategic factors.

In support of this efficient cost concept, AlintaGas notes that the ACCC, in its Final Decision on the Victorian gas transmission pipelines Access Arrangement, dated 6 October 1998, states:

> "… DORC valuations are based on a competitive concept. A return on replacement cost is the maximum that a monopoly firm could earn in a perfectly contestable market."

3.3.2 Bidding inflated prices should not be encouraged

The National Access Code should not be used to enable Service Providers to bid inflated prices for pipeline systems solely on the basis that they can recover a corresponding inflated price through third party tariffs. Sections 8.1(a), (b) and (d) of the National Access Code are intended to prevent this happening. If the sale price of the DBNGP is used as the initial Capital Base, it would result in the anomalous situation of Service Providers being willing to purchase assets at any cost, confident in the knowledge that they can recoup such costs from third party users over a period of time. If this interpretation of section 8 of the National Access Code were correct, the National Access Code would be "distorting investment decisions", contrary to one of the express objectives in section 8.1(d). It would defeat one of the purposes of competition policy reform, which is to prohibit monopoly asset owners from charging a monopoly rent for use of that asset.

The absurdity in Epic Energy's proposed initial Capital Base can be simply illustrated. Suppose one year after having purchased the DBNGP and prior to the Regulator approving the initial Capital Base, Epic Energy had sold the DBNGP to a related company for, say, $3.5 billion. On Epic Energy's argument, the initial Capital Base for the pipeline would then be $3.5 billion, when nothing about the pipeline had changed. In this scenario, it is difficult to see how the efficient cost of providing DBNGP haulage services could be different before and after Epic Energy sold the pipeline. It is also difficult to characterise the acquirer's recovery (were it permitted) of the extra $1 billion as anything other than monopoly rent.

AlintaGas submits that an excessive purchase price should not lead to excess tariffs, whether now or (through mechanisms such as the proposed deferred recovery account) in the future.

3.4 Epic Energy's interpretation of the National Access Code appears to be incorrect

Epic Energy has failed to provide the regulator with DAC and DORC valuations. However, assuming the purchase price is greater than both DAC and DORC, Epic Energy's entire argument to justify why the initial Capital Base should be valued outside the bounds of DAC and DORC appears to be found in the following two paragraphs of section 3.1 of Epic Energy's Access Arrangement Information:

> "Section 8.11 of the Code provides bounds within which the initial capital base for an existing covered pipeline would "normally occur". However, the Code does not make these bounds mandatory, and in fact, in Section 8.10 prescribes a number of other factors to be taken into account in setting the initial capital base. *The competitive bidding process through which Epic Energy acquired the DBNGP removed the initial capital base from within the indicative bounds of Section 8.11 of the Code.*
>
> *In the context of a competitive bidding process, the critical factor to be considered in establishing the initial capital base is the price Epic Energy paid for the DBNGP. This is consistent with Code requirements.* Section 8.10(j) identifies as one of the factors that should be considered in establishing the initial capital base "the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase". However, other requirements in Section 8.10 of the Code also apply (such as paragraphs (c), (e), (f), (g) and (h))." (italics added)

The propositions contained in the above paragraphs can be split into the following issues:

(a) the relevance of Epic Energy's competitive bid for the DBNGP; and

(b) the application of section 8.11 of the National Access Code, specifically whether the sale of the DBNGP displaces the boundaries created by the DAC and DORC valuation methodologies under sections 8.10(a) and 8.10(b) of the National Access Code.

AlintaGas submits that Epic Energy's arguments on both these matters are incorrect. AlintaGas submits that the correct application of sections 8.10 and 8.11 to the DBNGP requires an initial Capital Base which lies somewhere between the DAC and DORC valuations.

3.4.1 Epic Energy's references to the competitive bid process are irrelevant

Epic Energy does not explain why it considers the competitive bidding process to be relevant in determining the initial Capital Base. AlintaGas can identify two possible reasons, neither of which is tenable, as discussed below:

(i) Epic Energy may be suggesting that the competitive sale of the DBNGP was one of the factors giving rise to Epic Energy's claimed "regulatory compact", and presumably further that it is a term of that purported compact that the purchase price will form the initial Capital Base. This alternative is easily discarded.

AlintaGas has indicated previously to the Regulator that there was and is no "regulatory compact" or other agreement between any Epic Energy entity and AlintaGas or, to the best of AlintaGas's knowledge, the State, dealing with tariffs or tariff setting methodologies.

Even if there was a "regulatory compact", any such compact could not be binding on the Regulator. The claim that AlintaGas or the State entered into such a compact and by so doing purported to limit the statutory discretion of the Regulator is absurd.

(ii) Epic Energy's references to a "competitive bidding process" may be an attempt to confuse the DBNGP's sale with the competitive procurement provisions described in sections 3.21 to 3.36 of the National Access Code. AlintaGas submits that any suggestion along these lines is misconceived, and should be disregarded.

Sections 3.21 to 3.36 of the National Access Code provide an alternative method of setting reference tariffs. Rather than applying section 8 of the National Access Code, tariffs may be set through a competitive tender process under sections 3.21 to 3.36. In effect, if an organisation wishes to build a pipeline, the National Access Code allows it to seek tenders from contractors on the basis of the tariffs to be charged for services, rather than on the basis of the cost to construct the pipeline.

As an initial observation, even if it were meaningful to apply the competitive tender process in sections 3.21 to 3.36 of the National Access Code to the DBNGP sale, those provisions could not be applied. This is because (as section 3.21 makes clear) they can only be used in respect of pipelines that have not yet been built.

However, it is absurd to suggest or imply that sections 3.21 to 3.36 of the National Access Code are relevant. The tender process contemplated by those sections and the sale process undertaken for the DBNGP are directed at entirely different objectives. When a pipeline is to be constructed, which is the circumstance contemplated by sections 3.21 to 3.36, the project proponent will (all else being equal) seek to minimise the cost. In contrast, when a pipeline is being sold, one of the objectives of the vendor will be to maximise the price realised.

The sale of a regulated asset poses risks for bidders, as they seek to bid prices high enough to secure the asset, but low enough to generate a sustainable return in the regulated Reference Tariff environment after the asset's sale. In a nutshell, if a purchase price of $2.4 billion cannot be sustained at a tariff regulated in accordance with the National Access Code, then Epic Energy may have paid too much for the pipeline. Be that as it may, Epic Energy cannot now ask existing and future users to underwrite that over-expenditure through higher tariffs derived from an inflated initial Capital Base. This is so regardless of whether that underwriting arises by users paying the same tariff for a degraded service, or through notionally "deferring" the Capital Base until tariffs can be increased. Epic Energy has included both mechanisms in its proposed Access Arrangement.

3.4.2 Epic Energy's interpretation of sections 8.10 and 8.11 of the National Access Code is incorrect

Epic Energy claims in section 3.1 of its Access Arrangement Information that the competitive bidding process it entered into for the DBNGP removed the initial Capital Base from within the indicative bounds of section 8.11 of the National Access Code. AlintaGas requests the Regulator to reject this conclusion, and the interpretation of the National Access Code upon which it is based.

Under section 8.10 of the National Access Code, the Regulator should consider DAC and DORC valuations when determining the value of the initial Capital Base. Furthermore,

section 8.11 indicates that the value of the initial Capital Base should not normally fall outside the range of values determined under section 8.10(a) and (b). This is a clear indication that DAC and DORC valuations, in setting the boundaries on the initial Capital Base, are the two most important factors to consider regarding the value of the initial Capital Base.

Whether the Regulator can depart from the DAC/DORC boundaries depends on the meaning of "normally" in section 8.11 of the National Access Code. AlintaGas submits that one way to appreciate the test imposed by section 8.11 is to rephrase it in the negative. The question thus becomes whether the sale of the DBNGP is sufficiently abnormal, either as an infrastructure asset sale per se or in the case of the DBNGP sale in particular, to justify the Regulator departing from the DAC/DORC band. AlintaGas submits that it is not.

This interpretation is supported by the requirements of section 7.13(a)(iii) of the National Access Code. Section 7.13(a)(iii) requires only a summary of the assumptions and reasoning that resulted in the figure adopted as the initial Capital Base where the figure falls between the DAC and DORC valuations, but if a figure outside the range of the DAC and DORC valuations was selected it requires detailed reasons as to why. The more onerous information requirements of section 7.13(a)(iii) of the National Access Code in relation to a value outside the range of the DAC and DORC valuations highlight that such an outcome is expected to be an abnormal event requiring special justification.

AlintaGas submits that section 8.11 of the National Access Code is the paramount provision. Section 8.10 lists those factors that must be considered by the Regulator in determining the value of the initial Capital Base. Section 8.11 then states that after considering sections 8.10(a) to (k), the Regulator should not normally value the initial Capital Base outside the values of DAC and DORC.

AlintaGas submits that there is nothing in Epic Energy's Access Arrangement Information, and nothing in the factual circumstances of the DBNGP sale itself, which are sufficiently abnormal to justify departure from the DAC/DORC band. Accordingly, AlintaGas requests the Regulator to determine that the initial Capital Base for the DBNGP should rest somewhere between the DAC and DORC valuations.

3.5 Regulators have rejected use of purchase price for the initial Capital Base

AlintaGas's view that the purchase price of a pipeline system is not appropriate as the value of the initial Capital Base is consistent with current regulatory thinking in Australia. AlintaGas refers in this context to the Independent Pricing and Regulatory Tribunal's (**"IPART"**) decision regarding Great Southern Energy's Wagga Wagga Gas Distribution System. IPART determined an initial Capital Base for the relevant pipeline that fell between the DAC and DORC valuations, stating:

> "The Tribunal is of the view that the initial capital base should not normally be equated to the purchase price of the business. It is of the view that any apportionment of intangible assets to the network business should normally be excluded from the initial capital base." (page 17 of the Access Arrangement Information drafted and approved by IPART, September 1999)

Likewise, in its final decision concerning the Transmission Pipelines Australia Victorian assets on 6 October 1998, the ACCC assessed the various factors that are to be considered under the National Access Code when determining an initial Capital Base. The ACCC concluded that the valuation should not be in excess of the DORC valuation.

3.6 Epic Energy's own costings suggest a DORC valuation in the vicinity of $1 billion

It should be reiterated that Epic Energy's proposed initial Capital Base bears no relationship to the cost of construction of the DBNGP. Table 3.1b in Epic Energy's proposed Access Arrangement Information details Epic Energy's allocation of its purchase price to various DBNGP assets.

AlintaGas has not attempted to accurately determine a DORC valuation. A full assessment of the DORC valuation will require engineering studies to assess the impact of using modern materials to cater for pressures upwards of 15 MPa and to optimise pipeline size versus optimal compressor station configurations.

In its Moomba to Adelaide Access Arrangement, Epic Energy used a cost of $22,000 per inch-km[3] in deriving an ORC for the Moomba to Adelaide pipeline. This valuation does not include compression assets. A number of interested parties have commented that this cost is excessive. AlintaGas also considers it to be too simplistic a method for determining an ORC valuation.

However, if Epic Energy's costing is applied to the DBNGP, which has a diameter of 26 inches between Dampier and Kwinana Junction, the result is a rough valuation of the DBNGP pipeline assets (again excluding compression assets) of $572,000 per km, or $800 million for the first 9 zones. In its proposed DBNGP Access Arrangement, Epic Energy allocates $1,808.9 million to these same assets, that is, 2.26 times more than the rough value suggested by its own ORC costing methodology.

AlintaGas has applied the same proportionate valuation to estimate the ORC for the balance of Epic Energy's assets on the DBNGP, that is, those assets other than the Dampier-Kwinana Junction pipeline assets. This is a reasonable approach for the purposes of this discussion since the balance of Epic Energy's assets is only 15% of Epic Energy's total valuation. The result of this rudimentary assessment indicates that an ORC valuation is going to be in the vicinity of $1 billion. This indicative ORC valuation must then be depreciated in an appropriate manner to determine DORC.

Further support of the proposition that Epic Energy itself considers that the ORC valuation of the DBNGP should be less than $1 billion comes from an Information Memorandum prepared by Hastings, as manager of the AIF, issued on 28 May 1998. In that Information Memorandum, Hastings states:

> "Epic has publicly stated that it is committed to doubling the pipeline capacity to approximately 1,000 TJ/day at a cost of between $800 to $850 million over the next ten years."

Since the most economic way the DBNGP's capacity will be doubled is by extensive looping, the stated cost of doubling the DBNGP's capacity provides a very approximate benchmark ORC valuation for the DBNGP's current capacity.

3.7 AlintaGas expects the DAC valuation to be less than $1 billion

As discussed in AlintaGas's First Submission, there is insufficient information in the Access Arrangement to determine DAC or DORC valuations.

[3] That is, $22,000 per inch of pipeline diameter for each km of pipeline length.

A starting point for the DAC valuation might be the book value of the DBNGP assets as at 25 March 1998 when the DBNGP was sold to Epic Energy. The value of those assets not sold as part of the sale (primarily the Geraldton high pressure lateral and the section of pipe downstream of MLV 157) should be subtracted from this amount. Any subsequent investment which meets the tests in section 8.16 of the National Access Code should then be added and the total should be reduced by an appropriate amount for depreciation.

AlintaGas's 1997 Annual Report shows a value for Transmission Business assets (including the assets not sold to Epic Energy) of $937 million at the end of June 1997. AlintaGas therefore submits that a DAC valuation is probably less than $1 billion.

3.8 Depreciation Schedule is inappropriate

In the DBNGP Issues Paper, the Regulator asks whether the proposed method of calculating depreciation costs is consistent with the requirements of the National Access Code. AlintaGas submits that it is not.

Both the DAC and DORC valuations rely on the depreciation of assets. Table 3.1b of the Access Arrangement Information shows that Epic Energy proposes just $0.78 million in depreciation to 31 December 1999 on its costing of $2.449 billion of assets. This amount of depreciation is unreasonably low.

Epic Energy uses an annuity method of depreciation. This method keeps depreciation low during the early life of an asset. Depreciation will be kept to virtually nothing when, as Epic Energy is proposing, an annuity method of depreciation is combined with long asset lives.

Section 8.33(a) of the National Access Code says the Depreciation Schedule should be designed:

> "(a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly *where the calculation of the Reference Tariffs has assumed a significant market growth and the Pipeline has been sized accordingly*)". (italics added)

Epic Energy has not assumed any market growth in its forecasts beyond its already contracted capacity. Clearly, the DBNGP is a mature asset. As such, there would appear to be little justification for the heavily back-ended depreciation schedule proposed by Epic Energy.

Given the long lives of pipeline assets, the mature nature of the DBNGP and the lack of forecast market growth, AlintaGas considers a straight-line depreciation method would be more appropriate. Epic Energy proposed a straight-line depreciation method in its Moomba to Adelaide Access Arrangement.

3.9 Asset lives are excessive

Section 8.33(b) of the National Access Code says the Depreciation Schedule should be designed:

> "(b) so that each asset or group of assets that form part of the Covered Pipeline is *depreciated over the economic life* of that asset or group of assets". (italics added)

Epic Energy suggests a 100-year life for the DBNGP pipeline assets. AlintaGas submits that Epic Energy's proposed asset lives are excessive. For example, Hastings, as manager of the AIF, in an Information Memorandum released on 28 May 1998, states:

> *"The economic life of the asset is expected to be 65 years."*

The general impression obtained from a reading of section 3.7 of Epic Energy's Access Arrangement Information is that asset lives are significantly less than the lives being used for depreciation purposes. For example, Epic Energy, in detailing its proposed capital replacement program, estimates the life of UPS battery banks to be 10 years, air conditioning condensers and compressors to be 10 years, earthing systems to be 15 years, and the existing microwave system to be about 20 years. These lives do not correspond with Epic Energy's proposed Depreciation Schedule.

AlintaGas requests the Regulator to undertake a review of asset lives. For example, it would seem difficult to justify a 57 year life for compression assets, as proposed by Epic Energy, when a life of between 15 years and 20 years is generally assumed by industry. Use of the Depreciation Schedule as proposed by Epic Energy together with an annuity depreciation methodology will result in the Capital Base remaining at a higher level in future Access Arrangement Periods (and therefore higher tariffs in future Access Arrangement Periods). This is not justifiable under the provisions of the National Access Code. Furthermore, given the DBNGP is already 15 years old, high asset lives and an annuity depreciation methodology could result in the DAC and DORC valuations being overstated.

3.10 A deferred recovery account is inappropriate

In clause 3.4 of the Access Arrangement Information, Epic Energy proposes the use of a deferred recovery account. This will have the effect, illustrated in Table 3.3 of the Access Arrangement Information, of increasing the Capital Base from Epic Energy's proposed initial Capital Base of $2.57 billion to $3.37 billion by the end of the Access Arrangement Period.

AlintaGas submits that the use of a deferred recovery account on the DBNGP, which is intimately linked with the determination of an initial Capital Base and the tariff, is not in accordance with the National Access Code and should not be allowed. AlintaGas submits that there would be no need for a deferred recovery account if the initial Capital Base is set at a correct level (namely somewhere between the DAC and DORC valuations).

If the capital expenditure proposed on the DBNGP during the Access Arrangement Period is ignored, so that the DBNGP in 2005 is identical to the DBNGP today, then application of the deferred recovery account will result in the DBNGP's regulatory Capital Base increasing by more than $700 million in the five-year Access Arrangement Period. AlintaGas submits that this is an absurd outcome.

The ACCC, in its 10 September 1999 draft decision on AGL's Central West Pipeline Access Arrangement, states:

> "Under most conventional frameworks [AGL Pipelines] would be required to set tariffs much higher than currently proposed. This would compromise the expected rapid growth of the customer base, which would have the effect of raising the inherent risks for the project, and hence tariffs. A possible result of this could be that the [Central West Pipeline] might never have been built." (page 29)

In this case, the ACCC accepted the use of a deferred recovery account because the pipeline was a greenfields project without an established customer base. The deferred recovery account provides an opportunity for tariffs to be set at sustainable levels when initial demand is low. As demand grows through market development, the increased throughput enables recovery through the tariff of the deferred capital costs.

Two similar decisions to approve the use of a deferred recovery account have been made under the Victorian Access Code for Envestra Ltd's Mildura natural gas distribution system and Eastcoast Gas Pty Ltd's East Gippsland natural gas distribution system. Both cases were greenfields projects similar to the Central West Pipeline.

The DBNGP is completely different. It is not a greenfields situation. Rather, Epic Energy has long-term take-or-pay contracts for the majority of its firm capacity. There is very little spare capacity and Epic Energy is not forecasting any increase in its contracted capacity over the Access Arrangement Period.

A deferred recovery account should not be used as a way in which the purchaser of an existing pipeline can recover an excessive purchase price by setting tariffs that will be higher than the "stream of revenue that recovers the efficient costs of delivering the Reference Service" (see section 8.1(a) of the National Access Code).

A deferred recovery account will cause DBNGP tariffs to remain high and continue to increase for many years as Epic Energy attempts to recover its purchase price for the DBNGP.

AlintaGas submits that the DBNGP is a mature pipeline where the use of a deferred recovery account cannot be justified.

4. RATE OF RETURN

4.1 Summary of this section

In the DBNGP Issues Paper, the Regulator asks whether:

- the proposed rate of return that has been used to derive reference tariffs reflect a reasonable estimate of the market-determined cost of capital for the DBNGP assets; and

- reasonable values have been assigned to input variables of the capital asset pricing model.

AlintaGas submits that Epic Energy has not assigned reasonable values to input variables of the capital asset pricing model. As a result, Epic Energy's proposed rate of return, specifically a pre-tax real Weighted Average Cost of Capital (**"WACC"**) of 8.50%, reflects an over-estimation of the market-determined cost of capital.

AlintaGas submits that the DBNGP faces significantly lower risks than pipelines in the eastern states of Australia. As such, the pre-tax real WACC should be correspondingly lower than have been approved in other recent regulatory decisions in Australia.

These issues are discussed below.

4.2 WACC should be commensurate with market conditions and risk involved

Section 8.30 of the National Access Code states:

> The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with *prevailing conditions in the market for funds and the risk involved* in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service). (italics added)

Section 8.31 of the National Access Code states:

> "… 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. …" (italics added)

In assessing Epic Energy's proposed rate of return, AlintaGas has given consideration to:

- the risks involved in delivering the service;

- the prevailing market conditions for funds; and

- standard industry practice financing structures.

4.3 The DBNGP is less risky than pipelines in the United States

Epic Energy's proposed rate of return is based on a report by the Brattle Group (the **"Brattle Report"**) contained in Appendix 2 of the proposed Access Arrangement Information.

The Brattle Report focuses on a sample of five large US companies that own gas pipelines. The sample was chosen by a staff member of the United States Federal Energy Regulatory Commission because the sample was the:

> "most indicative of risks faced by gas pipelines" (Brattle Report, page 6)

The staff person actually said "I selected five publicly owned companies whose mix of business, in my opinion, fairly reflected the risk faced by natural gas transmission companies as of December 31, 1996, the latest date for which the data was available."[4]

AlintaGas has received advice from consultants with extensive experience in the North American regulatory environments. As a result of that advice, AlintaGas submits that it is not appropriate to utilise the sample group proposed in the Brattle Report since it is not comparable to the risks faced by the DBNGP.

The DBNGP is exposed to less risk than the United States' companies in the Brattle Report sample. The gas pipelines in the Brattle Report sample face a higher risk due to their competitive environment resulting in a lower level of firm demand and a shorter term for firm services. In addition, many United States' gas pipelines have faced a number of adverse circumstances, such as heavy take-or-pay losses resulting from gas purchase obligations, prior to unbundling. Further, companies in the sample used in the Brattle Report are generally not clear gas pipelines, but have as their asset bases a more diverse mix than simply gas pipeline assets. There is only one company in that sample that had 100% of its assets and revenue from pipeline operations.[5] Therefore, the comparison with the DBNGP is improper.

Risk is created in the United States by the greater competition between competing pipelines and the fact that regulated unbundled pipelines are going into high risk, unregulated ventures rather than solely competing in markets with multiple sources of gas supply. As such, AlintaGas submits that the Brattle Report sample is not comparable in any way with the DBNGP and as such, the Brattle Report should be disregarded.

If overseas utilities are to be used for comparative purposes, then Canadian pipelines are more representative of the risks faced by the DBNGP. In Canada, gas pipelines have essentially been monopolies with relatively long-term firm demand. Gas transmission pipelines in Canada tend to be long-distance pipelines connecting a geographic gas source to markets not traditionally subject to significant competition from other gas transmission systems.

The DBNGP is less risky than even the lowest risk Canadian pipelines. Unlike the Canadian pipelines, virtually all of the DBNGP's capacity is contracted on a firm basis for the duration of the 5-year Access Arrangement Period.

4.4 The DBNGP is less risky than other Australian pipelines

AlintaGas submits that the DBNGP faces a lower level of risk than that faced by transmission pipelines in the eastern states of Australia. This is because, unlike the DBNGP, pipelines in the eastern states are becoming exposed to competition from geographically diverse sources of gas. This is evidenced by the construction of competitive transmission pipelines such as that from the Bass Strait gas fields to Sydney.

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[4] Reference: Docket No. RP97-373, December 1997, George M. Shriver III {available as document 1807616 FERC RIMS}.

[5] Reference: Schedule D of the Shriver evidence.

AlintaGas also submits that the DBNGP faces a lower level of risk than that faced by gas distribution networks. This is because, unlike the DBNGP, haulage contracts on gas distribution networks are generally for shorter periods and tariffs are predominantly commodity based, creating revenue and return uncertainty.

AlintaGas's analysis suggests that the pre-tax real WACC should be between 5.5% and 6.5%. Accordingly, AlintaGas requests the Regulator to take account of the lower levels of risk on the DBNGP when approving an appropriate rate of return.

4.5 The DBNGP is less risky than the "all ordinaries" index

The Brattle Report proposes an equity beta for the DBNGP of 1.15. When applied to the Brattle Report's market risk premium of 6.5% it results in an equity risk premium for the DBNGP of 7.5%. This infers that an equity investment in the DBNGP is more risky than an investment in the "all ordinaries" index. AlintaGas does not accept this. AlintaGas submits that the equity beta is clearly less than 1.0.

Inherently, the DBNGP is a low risk asset, because:

- it links a single supply area to a single market;
- virtually all the available capacity is contracted for periods beyond the Access Arrangement Period;
- users on the DBNGP are generally large reputable organisations that are unlikely to default on their obligations;
- there is little or no potential for a second pipeline to be constructed within the Access Arrangement Period; and
- Epic Energy proposes to require payments for reserved capacity during events of force majeure.

The National Energy Board in Canada, in report RH-2-94 dated March 1995, which is still used as the benchmark for setting rates in Canada, considered the cost of capital for a benchmark pipeline. A benchmark pipeline is a pipeline owned by a hypothetical utility whose overall investment risks were characteristic of a low-risk, high-grade regulated pipeline. The National Energy Board concluded that:

> "a reasonable all-inclusive equity risk premium for the benchmark pipeline would be 300 basis points." (page 6)

In a release dated 6 December 1999, the National Energy Board of Canada continued to use the report RH-2-94 and advised that it had approved a rate of return on common equity of 9.9% for 2000 for eight major pipeline companies in Canada. The difference between the 9.9% return on common equity and the 6.12% yield on long-term (30 year) bonds gives an equity risk premium of 3.78%. This reflects the relatively low competitive risk of Canadian pipelines.

The decision of the National Energy Board aligns with AlintaGas's advice that in the United States and Canada the market risk premium is between 5.5% and 7%. Utilities are then generally considered to be 50% to 60% as risky as the overall market, such that the equity risk premium for utilities is between 3.3% and 4.2%. AlintaGas notes that these reflect

equity betas of 0.5 to 0.6. AlintaGas also notes that in the two tariff determinations undertaken in 1994 and 1997 for T1 tariffs on the DBNGP, an equity beta of 0.8 was used on a gearing ratio of 80%.

Other recent Canadian regulatory decisions further reinforce AlintaGas's contention that the equity beta should be significantly less than 1.0. For example, the British Columbia Utilities Commission, one of Canada's provincial regulators, in a decision contained in Letter No. L-62-99 dated 29 November 1999, determined an equity risk premium of 3.46%, which reflects an equity beta of 0.5 to 0.6.

A further example is Decision U99099, relating to Electric Tariff Applications, where the Alberta Energy Utilities Board determined that for the test years of 1999 and 2000, the equity risk premium should be between 3.25% and 3.75%. This Decision applied to EPCOR Generation Inc./EPCOR Transmission Inc. and TransAlta Utilities Corporation.

AlintaGas submits that it is important to ensure that the equity beta is set to reflect the equity risk associated with the DBNGP, rather than to be overly concerned with the separate asset and debt betas.

AlintaGas requests the Regulator to determine the equity beta to a value significantly less than 1.0 so as to reflect the low risks faced by the DBNGP.

4.6 Gearing level is too low

Section 8.31 of the National Access Code states:

> "… 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."

AlintaGas submits that standard industry practice as it applies to the DBNGP requires a gearing level on the DBNGP to be not less than 75%.

In its calculation of the WACC, Epic Energy proposes a gearing level of 55%. However, an analysis of the 1999 Financial Statements of the AIF, which holds a 4% interest in the DBNGP, indicates that the level of debt financing on the DBNGP is around 75%. This debt level indicates that Epic Energy's proposed gearing level of 55% is too low. It also infers that the financial institutions were sufficiently satisfied of the low risks involved that they were prepared to finance the acquisition of the DBNGP up to a 75% gearing level. As indicated later, this debt has been financed at low interest rate margins, further supporting the contention that a gearing level of 75% is appropriate for a pipeline with the DBNGP's low risk profile.

In the United States, the Federal Energy Regulatory Commission ("FERC") has accepted debt levels of between 50% and 60%. However, these relatively low debt levels have been established to reflect the higher risk of the competitive environment in the United States and are not applicable to the DBNGP's situation. FERC relies on actual capital structures unless they are unreasonable. On this basis, FERC would support the use of 75% debt for the DBNGP.

In Canada, where gas pipelines have essentially been monopolies, and in this regard provides a similar risk profile to the DBNGP, notional gearing to debt levels up to 75% have been accepted. Canadian regulators have taken the position that a higher equity component is

inefficient if a pipeline utility is able to borrow funds at a rate lower than the cost of equity, having regard to the associated income tax.

AlintaGas also notes that on the two occasions that tariffs have been determined for the DBNGP in accordance with the GTRs, a gearing level of 80% was assumed.

4.7 Other variables should be modified

AlintaGas submits that a number of variables used in the Brattle Report to calculate the WACC, in addition to the equity beta and gearing ratio, are inappropriate. AlintaGas requests the Regulator to take into account the low risks associated with the DBNGP when deciding appropriate values for the variables. A brief discussion of some of the other variables is provided below.

4.7.1 Proposed asset beta of 0.58 and debt beta of 0.12

As noted previously, AlintaGas is of the opinion that the focus of risk in determining the rate of return should be on the equity beta. However, to the extent the Regulator determines that the equity beta should be calculated from the gearing level and the asset and debt betas, AlintaGas notes the following:

(a) an asset beta of about 0.2 is consistent with equity betas in the range of 0.5 to 0.6 and a gearing level around 75%.

(b) Epic Energy's proposed debt beta of 0.12 is not realistic if the equity beta is set at a level reflecting the low risk of a monopoly pipeline. In this regard, AlintaGas notes the ACCC's 25 January 2000 decision, "NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04", where the ACCC states:

> "Since the release of the draft decision, the Commission has, as noted in its draft Central West Pipelines decision, undertaken further work in this area. As a result, the Commission now considers that the feasible range for the debt beta lies between 0.00 and 0.06." (page 36)

4.7.2 Proposed risk free rate of 6.40%

Recent work by the ACCC, referred to in the ACCC's 10 September 1999 draft decision on AGL's Central West Pipeline Access Arrangement, concluded that a risk free rate of 5.83% was appropriate. Professor Kevin Davis of the Department of Accounting and Finance at the University of Melbourne, in a draft paper prepared in October 1999 for the South Australian Independent Pricing and Access Regulator (**"SAIPAR"**), recommends a risk free rate of 6%.

4.7.3 Proposed market risk premium of 6.5%

In Australia, a market risk premium of about 6% is generally consistent with recent regulatory decisions. The ACCC's draft report, "Statement of Principles for the Regulation of Transmission Revenues", dated 27 May 1999, states:

> "… it is probable that a market risk premium of say 5 per cent is more appropriate now, than, say the 6 per cent considered as appropriate, at the time of the Victorian Gas Access Arrangements Decision." (page 79)

4.7.4 Proposed debt premium of 1.2%

An Information Memorandum prepared by Hastings, issued on 28 May 1998, states that in financing for the DBNGP:

> "Margins for arrangers range between 85 bp and 100 bp over Bank Bills, depending on the interest cover ratio."

This clearly reinforces the view that the DBNGP is a low risk asset.

AlintaGas also notes that the ACCC, in its 25 January 2000 decision, "NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04", has used a debt premium of 100 basis points, noting that:

> "this figure is consistent with the margin used by the Commission in its draft Central West Pipelines decision and by IPART in its NSW electricity distribution network revenue and prices determination." (page 20)

4.7.5 Proposed payout ratio, franking ratio and utilisation ratio

AlintaGas notes that these parameters have not featured in recent regulatory decisions. AlintaGas questions the relevance of these parameters in determining the WACC.

4.7.6 Proposed gamma franking credits of 0.44

Professor Davis in his report addressing the WACC in the South Australian gas industry says it is difficult to see any reason for adopting a value of γ below 0.5. This opinion is consistent with the figure of 0.5 adopted in the ACCC's NSW Decision.

4.8 Conclusion

The DBNGP will be exposed to very little risk during the Access Arrangement Period. All firm capacity upon which the financial projections are based is contracted for the Access Arrangement Period. Also, given gas market growth forecasts in the South-West of Western Australia and since existing users have long-term fixed charge capacity contracts with Epic Energy, there is virtually no prospect of a competitive gas pipeline being built in the foreseeable future. AlintaGas submits that regulatory rate of return applied to the DBNGP should reflect this low risk profile.

5. TARIFF

5.1 Summary of this section

In the DBNGP Issues Paper, the Regulator asks whether:

- the methodology for determining total revenue for the DBNGP is consistent with that provided for by the National Access Code; and
- the allocation of costs underlying the reference tariff schedule is consistent with the requirements of the National Access Code.

AlintaGas submits that neither the methodology nor the allocation of costs undertaken by Epic Energy in arriving at its proposed Firm Service tariff is appropriate. These issues are addressed in this section of this submission under the following headings:

- previous tariff setting methods used for the DBNGP, coupled with Government policy statements, have created a marketplace in which user expectations were for a full-haul tariff of $1.00 per GJ in 2000;
- the relevance of the terms and conditions of the service under discussion;
- AlintaGas has calculated an indicative headline tariff of about $0.84 per GJ;
- if a 95% fixed tariff component and 67% CPI escalation of the full tariff are used, the headline tariff reduces further;
- Epic Energy's proposed non-capital costs require scrutiny;
- Epic Energy's proposed penalties of $15.00 per GJ are probably illegal, but should be removed in any event.

5.2 User expectations were for a reducing T1-tariff of $1.00 per GJ in 2000

Sections 8.10(f) and (g) of the National Access Code require the Regulator, when considering the initial Capital Base for an existing pipeline which is coming under the National Access Code for the first time, to consider :

> "(f) the basis on which Tariffs have been (or appear to have been) set in the past, …;
>
> (g) the reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code".

The basis on which tariffs have been set in the past is a depreciated actual cost methodology. The methodology was developed by the Energy Implementation Group in 1994, and applied under the GTRs. It was reviewed extensively by industry participants via the Gas Transmission Consultative Committee.

This has proven to be a sound basis for determining tariffs. It is a methodology tested and accepted by users, and is consistent with the cost of service methodology in section 8.4 of the National Access Code.

The reasonable expectations of users are an important aspect in determining tariffs. This is clearly expressed by the ACCC in its draft decision on AGL's Central West Pipeline, where the ACCC states:

> "The [Central West Pipeline] is still at the beginning of its useful life as it has only recently been commissioned. Consequently, *crucial issues* for an established pipeline, *such as to the previous history of charges levied*, are of little importance here". (italics added) (page vi)

The DBNGP is an established pipeline, where the previous history of charges levied is a relevant issue. On the DBNGP, there is a history of reducing tariffs. In 1995, the full-haul T1 100% load factor tariff was $1.25 per GJ. At a re-determination in 1997, the tariff was reduced for 1998 to $1.19 per GJ. Under the *Dampier to Bunbury Pipeline Regulations 1998*, this was further reduced in 1999 to $1.09 per GJ in 1999 and to $1.00 per GJ in 2000.

The expectations of users to see a reducing tariff regime have been enunciated by the Minister for Energy. For example, Hansard reports that, in the second reading of the *Gas Pipelines Access (Western Australia) Bill* on 18 June 1998, the Minister for Energy said:

> "The transitional access regime contained in the Dampier to Bunbury Pipeline Regulations 1998 came into effect on 25 March when the Dampier to Bunbury natural gas pipeline assets were transferred to the new owner. That regime applies until 1 January 2000 or until an Access Arrangement is approved for that pipeline under the code. The transitional regime features negotiability of tariffs and declining capped reference tariffs. *Firm full-haul tariff at 100 per cent load factor will fall from $1.19 per gigajoule to $1.00 per gigajoule* by the year 2000. Existing transmission contracts will be grandfathered, although *the new owner of the Dampier to Bunbury natural gas pipeline is obligated to offer the current declining capped tariffs to existing shippers* which are not exempt contractors." (italics added)

The Regulator is, of course, independent, and so is not bound by the Government's expectations expressed in the preceding passage. However, AlintaGas submits that the Regulator can form a view that existing users, including AlintaGas, reasonably expect a T1-equivalent postage stamp service tariff of no more than $1.00 per GJ under the National Access Code.

5.3 The relevance of the terms and conditions of the service under discussion

The users' expectations discussed above centred around the terms and conditions of a T1-equivalent Reference Service. Clause 2.1 of Epic Energy's Access Arrangement Information states:

> "The "tariffs" were widely referred to by the State during the sale process of the DBNGP. The "tariffs" were not, however, a complete specification of the tariffs for Firm Service. Epic Energy has therefore developed its proposed Reference Tariff and Access Arrangement recognising the commitments it made to the State at the time it purchased the DBNGP. At the same time it has looked to refine and improve the structure where appropriate."

AlintaGas reiterates that to its knowledge no "commitments" were given by Epic Energy to the State and, for that matter, by the State to Epic Energy.

Epic Energy confuses the situation by suggesting that there was doubt as to what (reference) service was contemplated. There was, and is, no such doubt. Firstly, to AlintaGas's knowledge, all discussions regarding the haulage service were based on the T1 service because that was the only service provided to third party users at the time of the sale. Secondly, as AlintaGas discussed in its Second Submission, Epic Energy has previously

explicitly proposed to offer a T1-equivalent Reference Service and made it clear that its tariff proposals were developed in the context of such a service.

Epic Energy proposes to make use of what it claims was the doubt regarding the terms and conditions to apply to its proposed Reference Service, by putting forward a proposed Firm Service which has been stripped of many elements of the T1 service.

The large-scale calculations required by section 8 of the National Access Code produce tariff outcomes that are largely independent of the detailed terms and conditions of the service being offered. However, this does not mean that a Service Provider is free to offer, as Epic Energy is attempting, substantially degraded services in place of a balanced service it was previously providing. The National Access Code provides three avenues for the Regulator to prevent this:

- first, the Regulator must be satisfied under section 3.6 of the National Access Code that the proposed terms and conditions are reasonable;

- second, the Regulator is expressly required under section 8.30 of the National Access Code to consider the impact the terms and conditions of the Reference Service have upon the Service Provider's risks (for example, the degree to which the Service Provider is proposing to shift risk onto users) in setting the WACC; and

- finally, the Regulator can identify the extent to which the elements stripped from the previous T1 service are to be offered as separate Services, whether Reference Services or otherwise, because sections 8.2(b) and 8.38 of the National Access Code require the Total Revenue to be apportioned across all Services, not just the main Reference Service. This point can be summarised as follows:

  > The T1 service is a relatively complete service. Assuming for the moment that it is the only haulage or other Service provided by the DBNGP, it may be appropriate to apportion the whole of the Total Revenue to that Service. If the T1 service is then subdivided into a range of Services, being a Firm Service, a Park and Loan Service, a Seasonal Service, a Peaking Service, an Odorisation Service, and a Secondary Market Service, the Total Revenue must be apportioned across all of those Services. To apportion the whole of the Total Revenue to just one Service, the Firm Service, is to permit over-recovery by the Service Provider.
  >
  > For example, a portion of Epic Energy's revenue will be obtained from the Seasonal Service. Epic Energy has already contracted a significant quantity of seasonal capacity, so it knows there is a demand for the service and can readily estimate revenue from the service. However, in the proposed Access Arrangement, Epic Energy proposes that the Seasonal Service be rebateable. Epic Energy thus excludes Seasonal Service revenue from the tariff determination. AlintaGas considers this to be inappropriate.

5.4 AlintaGas estimates an appropriate tariff to be about $0.84 per GJ

AlintaGas has estimated a full-haul firm tariff for the T1 service provided on the DBNGP.

Without access to all the necessary information, a number of assumptions have been made. However, AlintaGas submits that its tariff estimate is sufficiently acceptable as to provide a

useful guide to the T1 service tariff and as such should be given due consideration. The tariffs differ substantially from Epic Energy's proposed Firm Service tariff. AlintaGas requests the Regulator to consider the issues raised in this section when assessing Epic Energy's tariff proposals.

In estimating the T1 service tariff, AlintaGas has used Epic Energy's capacity and demand forecasts in section 6 of the proposed Access Arrangement Information and Epic Energy's annual non-capital cost forecasts in section 4.

In estimating the T1 tariff, AlintaGas has used a straight-line depreciation on an initial Capital Base of $1.0 billion with an average asset life of 65 years. A range of pre-tax nominal WACCs were used. They were equivalent to pre-tax real WACCs of between 5.6% and 6.5%.

AlintaGas submits that an appropriate 100% load factor full-haul firm tariff for the DBNGP is between $0.79 per GJ and $0.84 per GJ.

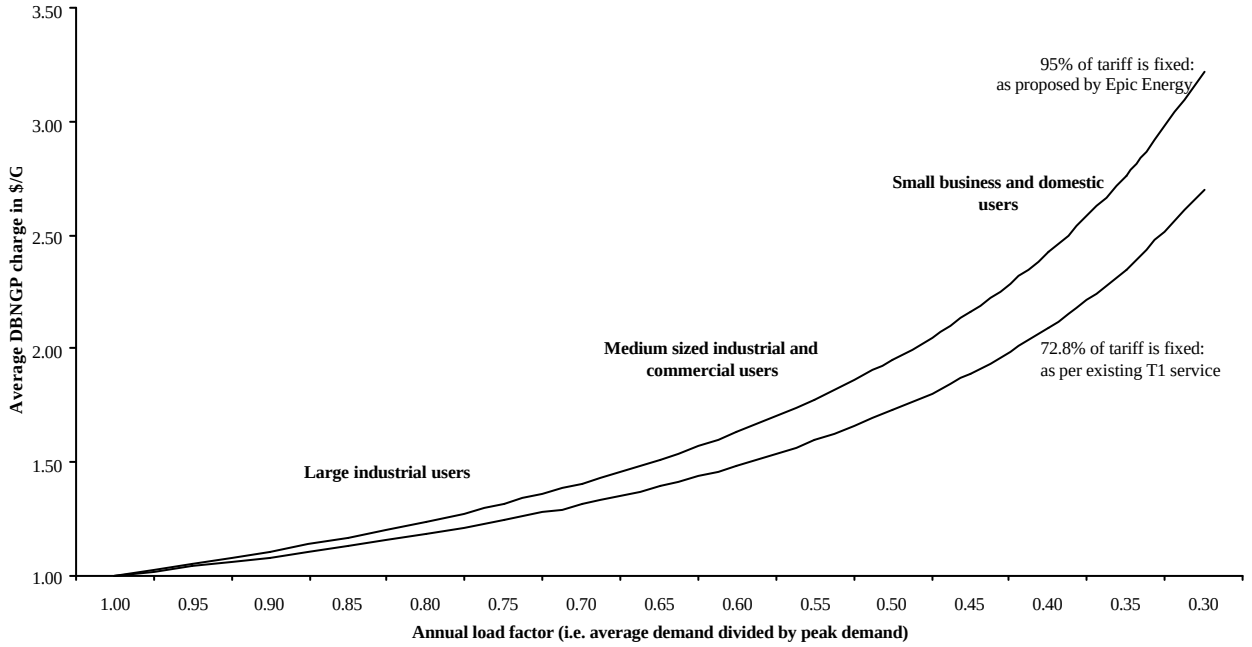
In deriving this tariff it has been assumed that 75% of the 100% load factor tariff is a fixed capacity charge component that does not escalate over the Access Arrangement Period. The remaining 25% of the 100% load tariff is a commodity component that escalates at 75% of CPI. The tariff was derived assuming a postage stamp service downstream of compressor station 9 and distance related charges upstream of compressor station 9, as is the case with the current T1 service tariff.

5.5 Using some of Epic Energy's assumptions will further reduce AlintaGas's estimated headline tariff

5.5.1 95% of the tariff being fixed favours Epic Energy

Epic Energy proposes to receive 95% of its revenue from the Firm Service as a fixed charge. Thus, Epic Energy will receive payment for 95% of the tariff irrespective of the quantity of

Impact on price per GJ of different fixed charge components in the firm service tariff assuming a total charge of $1.00 per GJ at 100% load factor



gas being delivered within a user's capacity. This 95% fixed charge component is even greater if the fixed Delivery Point Charges are added. In contrast, 72.8% of the current T1 tariff is a fixed component with the rest varying depending on a user's capacity usage.

The graph above shows the impact on tariffs that such a high fixed component proposed by Epic Energy will have on users. A user that has a low load factor, which is typically the case for small business and residential users, will on Epic Energy's model pay about $0.40 per GJ more for its gas transportation than it would if only 72.8% of the tariff was fixed.

The use of a high fixed charge component within the tariff provides greater certainty to Epic Energy that it will meet its revenue forecasts. It further reduces Epic Energy's risk exposure by moving that risk to users, who must pay higher per unit transportation charges.

AlintaGas submits that, by structuring tariffs on the DBNGP in which 95% of the headline tariff is fixed, the attractiveness of the small business and residential gas market to gas retailers will be diminished.

5.5.2 Escalating the tariff at 67% of CPI favours Epic Energy

Epic Energy proposes escalating the entire reference tariff plus all other charges at 67% of CPI. This allows for a lower headline tariff but will result in an inexorable increase in tariffs over time. In contrast, the existing T1 service capacity charge does not escalate, whilst the commodity charge escalates with the change in cost to Epic Energy of compressor fuel and at 75% of CPI for other costs. This is a significantly lower escalation rate than that proposed by Epic Energy. For the purposes of illustrating this point, assume that the whole of the T1 service commodity charge increases at 75% of CPI and that the commodity charge is 25% of the total tariff. The total increase in the T1 tariff for a user with a 100% load factor will be 18.75% of CPI. This compares to an escalation of 67% of CPI proposed by Epic Energy.

Again Epic Energy's proposal will be a bigger burden on end-users with a low load factor, such as small business and residential users. For the T1 service tariff, where there is no escalation on the capacity charge, the effective escalation rate reduces as the load factor reduces, whereas Epic Energy's effective escalation rate remains constant at 67% of CPI.

AlintaGas submits that Epic Energy should be asked to justify the escalation of those parts of its tariff which provide a return on capital when Epic Energy is already compensated for anticipated CPI increases through use of a nominal WACC in determining the required revenue.

The use of a CPI escalator should be treated with caution given that CPI is expected to be abnormally high in 2000/01 due to the introduction of a Goods and Services Tax (**"GST"**) from 1 July 2000. Use of a 67% CPI tariff escalator may provide Epic Energy with an unexpected and unreasonable windfall gain because of the impact of GST on CPI. Terra Gas Trader's supplementary submission to SAIPAR on Envestra's proposed Access Arrangement for the South Australian gas distribution division states:

> "Economic forecasters are typically projecting a CPI for 2000 (calendar year) and year ending June quarter 2001 of 5% to 6%, compared to underlying inflation of 2.0 to 2.5% pa."

AlintaGas requests the Regulator to consider the impact of GST when determining the tariff.

AlintaGas submits that the escalation of prices using a CPI mechanism is acceptable if it is a properly designed incentive mechanism. However, AlintaGas submits that Epic Energy's proposed escalation mechanism is inappropriate.

5.6 Non-capital costs should be scrutinised

In an Information Memorandum issued on 28 May 1998, Hastings said:

> "operating expenses (excluding depreciation) represent approximately 18 percent of total revenue at about $208 million in 1997."

Thus, Hastings estimated that DBNGP operating costs in 1997 would be $37 million. Hastings also indicated there was considerable potential to reduce costs. Epic Energy is forecasting that operating costs will be $39 million in 2000.

Epic Energy has recently rationalised its operations Australia wide by merging/downsizing its South Australian and Western Australian offices and centralising its maintenance and control centre operations. AlintaGas submits that DBNGP operating costs should reduce, not increase.

AlintaGas requests that the Regulator scrutinise Epic Energy's operating cost forecasts, to ensure they meet the requirements of section 8.37 of the National Access Code.

Furthermore, some of Epic Energy's planned capital investment is of an operational nature and should already be incorporated in Epic Energy's operating budget. Examples are flood damage mitigation, corrosion protection, replacement of seals on GEAs, and maintain and update tools.

AlintaGas also notes that in its Financial Statements for the year to 31 December 1998, Epic Energy received $2.259 million from pipeline maintenance activities, which is in addition to its revenue from gas haulage.

AlintaGas requests the Regulator to ensure that only those costs incurred in providing the Reference and non-Reference Services are included within Epic Energy's forecasts of operating expenses.

5.7 Epic Energy's proposed $15.00 per GJ surcharges are probably illegal, but should be removed in any event

For the reasons summarised shortly, AlintaGas considers that the proposed "rates and charges" are unlawful and unenforceable penalties which should not be approved for inclusion in an access contract.

Independently of that point, however, AlintaGas requests that the Regulator consider whether in any event a regime of penalties and surcharges is appropriate or will best achieve the objectives of the National Access Code. The DBNGP has operated as a fully-contracted third party access pipeline since 1 January 1995 with no peaking, balancing, nominations, overrun or unavailability surcharges, and with no evidence of either the Service Provider or users having suffered as a result.

The proposed Firm Service terms and conditions are drafted in such a manner that most current users will be unable to avoid paying some or all of the penalties. AlintaGas's legal advice is that the various "rates and charges" set out in Schedule 1 to the proposed Terms and

Conditions are very likely to be struck down as penalties. A contractual clause that purports to impose a penalty is invalid and, therefore, unenforceable. A clause is a penalty if it is included in a contract to coerce a party into complying with the party's obligations under the contract. A clause is likely to be a penalty if it is not a genuine pre-estimate of damage. A court of law is likely to view a clause as a penalty if the sum stipulated is extravagant and unconscionable in amount in comparison with the greatest loss that could conceivably be proved to have followed from the breach. A charge of about 15 times the full-haul delivery price is likely to satisfy such a test.

Further, a contractual provision will be presumed to be a penalty when a single lump sum is made payable by way of compensation, on the occurrence of one or more or all of several events, some of which may occasion serious and others but trifling damage. The fact that the proposed rates and charges in Schedule 1 to the Terms and Conditions are all set at the same level suggests they are arbitrary and punitive.

If there are to be any surcharges, which AlintaGas questions, then each surcharge should be determined separately and should be related solely to any additional cost Epic Energy would incur as a result of the user exceeding the particular limit.

Clause 6.5 of Epic Energy's proposed Terms and Conditions provide Epic Energy with the right to curtail users that may compromise the operation or integrity of the DBNGP as a result of an excessive imbalance. Clause 13.2 of the proposed Terms and Conditions also indemnifies Epic Energy against direct and indirect damage if a user willfully disregards its obligations. Thus, given the rights Epic Energy is proposing to expressly retain, there does not appear to be a justification for the imposition of penalties.

Finally, if surcharges are to be retained at either the current level or at some other level, AlintaGas submits that the effect of those surcharges must be taken into account when setting the headline tariff. If, as would presently be the case, a significant proportion of users will pay the surcharges on a regular basis, that revenue stream must be deducted from the revenue apportioned to the headline tariff, or Epic Energy will achieve a windfall gain.

The position is analogous to the proposed non-Reference Services, some of which indeed appear to be designed so that the proposed penalties act as an incentive for the user to buy the additional service. If Epic Energy is, or should be, anticipating any substantial revenue from the ancillary services, that revenue must be deducted from the revenue pool allocated to the Firm Service Reference Tariff.

6. OTHER ISSUES

6.1 Summary of this section

The DBNGP Issues Paper asks whether the proposed Terms and Conditions are reasonable in the context of the DBNGP. AlintaGas submits that they are not reasonable. Some of the issues that relate to the proposed Terms and Conditions are dealt with in this Section. Specifically, the following issues are discussed:

- the lack of a core haulage obligation;
- the Secondary Market;
- the treatment of overrun capacity;
- long term capacity relocation;
- imbalance and peaking limits;
- the zonal pricing system;
- the "permissible limit"; and
- Epic Energy's demand forecasts.

6.2 There is no core haulage obligation

AlintaGas submits that there is a fundamental oversight in Epic Energy's proposed Terms and Conditions, namely that there is no express obligation on Epic Energy to accept gas, and no obligation upon it to deliver gas. These two obligations should form the essence of a haulage contract.

The closest that the proposed Access Arrangement comes to identifying and imposing the core haulage obligations appears to be in section 6.2 of the proposed DBNGP Access Arrangement, which defines the Firm Service. However, a definition of Firm Service, as in section 6.2, as one in which Epic Energy takes receipt of gas and delivers gas to the user, does not impose an obligation on Epic Energy to do either.

Furthermore, the proposed Terms and Conditions do not quantify in any way the user's entitlement to receive gas at a Delivery Point. Under the GTRs and 1998 Regime there are express statements to indicate that in return for each energy quantity of gas delivered into the DBNGP by the user, the user receives a right to draw out an equivalent energy quantity of gas. AlintaGas submits that the absence of any such gigajoule-to-gigajoule link should be rectified.

6.3 The Secondary Market is inappropriate

In Epic Energy's proposed Access Arrangement, the Secondary Market is central to ensuring a user can fully utilise its capacity. AlintaGas submits that the Secondary Market appears to be complex and inflexible. Epic Energy will gain most from an inflexible Secondary Capacity market because users will not be able to sell or buy Secondary Capacity in an effective manner. Some users will have an excess of unused firm capacity whilst other users

will have purchased overrun capacity from Epic Energy. In both cases, Epic Energy benefits at the expense of the interests of users.

AlintaGas also submits that it is inappropriate for Epic Energy, which stands to gain most from the Secondary Market, to be able to unilaterally change the Secondary Market rules without the Regulator's approval.

There is sufficient flexibility within the T1 service for a user to get access to additional capacity and to sell unused capacity to other users. In the T1 service, a user has the right to purchase interruptible capacity from Epic Energy that may be available on a day. A user can also buy capacity directly from other users that might have spare contracted capacity, or a user can sell its own spare contracted capacity, assuming another user has a requirement for additional capacity on a day.

This capability to trade capacity is possible because of the right a user has in the T1 service to deliver gas to Delivery Points at which the user does not have contracted capacity. AlintaGas considers this Delivery Point flexibility to be an important feature of the T1 service that Epic Energy is not providing within its proposed Firm Service, to the detriment of users. Delivery Point flexibility was limited in the 1994 version of the GTRs. It was introduced in 1997 after extensive development by the Gas Transmission Consultation Committee. For Epic Energy to propose its removal is a significant retrograde step, which seems unreasonable and difficult to justify on technical or operational grounds, given that the facility has been in place for well over two years without apparent difficulty.

Rather than providing an interruptible service and Delivery Point flexibility, Epic Energy is proposing a Secondary Market. Section 1(e) of Epic Energy's proposed Secondary Market Rules states:

> "It is intended to provide purchasers of Capacity on the Secondary Market with Capacity that is effectively Firm Service."

AlintaGas contends that users do not want a Secondary Market that provides users with firm capacity. Rather, users would benefit, both in the sale and purchase of capacity, if there were an interruptible service combined with Delivery Point flexibility. AlintaGas understands that interruptible services are commonly available in the United States and Canada.

Furthermore, because Epic Energy is free to negotiate interruptible non-Reference Services with users and prospective users, but is not making such flexibility available to users wishing to sell capacity on the Secondary Market, Epic Energy will be in a position to undercut any user selling capacity on the Secondary Market.

Finally, since only users with a contract for Firm Service are to be permitted to market capacity on the Secondary Market, users with grandfathered T1 capacity will be excluded unless Epic Energy agrees to such users marketing capacity on the Secondary Market. In view of the fact that Epic Energy forecasts no load growth for the Access Arrangement Period, this means that the Secondary Market will probably stand idle for the first 5 years.

6.4 Overrun capacity is inflexible and complicated

Unlike the Delivery Point flexibility available within the T1 service, AlintaGas submits that Epic Energy's proposals for capacity relocation and overrun capacity are inflexible and complicated.

A user cannot have gas delivered to a Delivery Point at which it does not have contracted capacity except via the Secondary Market. This significantly increases the risk for users with only one or two Delivery Points. Capacity relocation is an essential tool in mitigating the risk associated with downstream market fluctuations, or even the short-term costs associated with customer downtime. If a user is delivering gas to one particular plant, which closes for a week-long maintenance session, the user and/or the customer needs the ability to relocate the capacity to other "swing" users such as Western Power or AlintaGas, in order to defray the cost of the capacity otherwise standing idle.

Even when a user does have contracted capacity at a number of Delivery Points, so that it can move the capacity around among its own Delivery Points, the proposed ability to relocate capacity appears to be inflexible and complicated.

Under Epic Energy's proposed Firm Service, a user can relocate unused capacity at one Delivery Point to another upstream Delivery Point. However, any such capacity is interruptible at Epic Energy's discretion.

A user can only relocate capacity to a downstream Delivery Point with Epic Energy's written permission. Again, such relocated capacity is interruptible at Epic Energy's discretion. Users, in order to maximise the use of firm capacity, require the flexibility to move capacity to other Delivery Points at short notice. The need to obtain written permission appears unnecessary and restrictive.

Further, AlintaGas considers it inappropriate that overrun capacity should be interruptible at the absolute discretion of Epic Energy whilst a user has unused firm capacity. If a user exceeds its total firm contracted capacity then it is reasonable that the excess taken by the user should be overrun capacity and subject to curtailment and overrun charges. But it is not appropriate for capacity used at a Delivery Point in excess of the users' contracted capacity at the Delivery Point to be interruptible if the user has unused contracted capacity at other Delivery Points in the South-West region.

Again, AlintaGas notes that Delivery Point flexibility and the aggregation of capacity across Delivery Points were the subject of extensive discussion and development by the Gas Transmission Consultation Committee, and that the 20 November 1997 amendments to the GTRs introduced a regime which provided a reasonable balance between the pipeline operator's reasonable technical and operational needs, and users' commercial and operational requirements. While Epic Energy must be permitted and encouraged to innovate, AlintaGas submits that Epic Energy should not be allowed to arbitrarily erode balanced positions which have been settled for the DBNGP by an extended period of industry consultation and review. Furthermore, AlintaGas notes that as with the Secondary Market, the more Epic Energy is able to restrict the ability of users to relocate capacity for short periods on short notice or to aggregate capacity across Delivery Points, the greater Epic Energy's chances of selling additional capacity services while still retaining the fixed charges on the capacity which is temporarily not required at the particular Delivery Point. Epic Energy thus has a direct commercial interest in restricting the reasonable flexibility of users in this regard.

AlintaGas submits that the capacity overrun mechanism proposed by Epic Energy is inappropriate. It will provide Epic Energy with additional revenue over and above a reasonable return through the sale of overrun capacity to a user requiring additional capacity at one Delivery Point even though the user has spare capacity at another Delivery Point.

6.5 Long-term capacity relocation and relinquishment

Epic Energy has not proposed the inclusion of a long-term capacity relocation mechanism, such as was available to shippers under the GTRs and the 1998 Regime. Section 3.3 of Epic Energy's proposed Terms and Conditions refer to the relocation of Delivery Point MDQ on a "Spot Basis". The definition of "Spot Basis" refers to relocation to another Delivery Point for no longer than a day. Similarly, at section 3.5 of the proposed Terms and Conditions, "Receipt Point Flexibility" is dealt with on a daily basis.

Long-term relocation of capacity is an important requirement for users to defray risk in the gas sales market. It is particularly important for smaller users, users with one or only a few Delivery Points, and users without a diversified load. However, it is also a significant market risk issue for a larger user such as AlintaGas, who supplies a number of major end-gas users directly from the DBNGP. Long-term relocation of capacity is a measure, short of relinquishment, by which a user can deal with loss of a gas sales customer. If a gas consumer supplied from a particular outlet point ceases using gas, the user is left with stranded capacity. AlintaGas submits that this is inappropriate and not economically efficient.

Similarly, Epic Energy's proposed Access Arrangement does not include any capacity relinquishment mechanisms. The GTRs and the 1998 Regime contained a relinquishment mechanism which preserved considerable flexibility and commercial independence for the DBNGP operator but which nonetheless provided an avenue for users to release capacity left stranded by loss of particular gas customers or market shrinkage.

The omission of these two mechanisms from the proposed Access Arrangement shifts further risk onto users, and also presents Epic Energy with an opportunity for windfall gains. If a user's capacity is left stranded at a Delivery Point because the gas consumer has shifted to another supplier, and the user is unable to relocate or relinquish the capacity, Epic Energy can effectively sell the same capacity to the new user while continuing to receive 95% of the headline tariff from the original user. AlintaGas submits that is economically inefficient and not fair and reasonable.

6.6 Imbalance and peaking limits are too restrictive

6.6.1 Imbalance limits

The T1 service has imbalance limits of ±8%. Surcharges are not currently applied if a user exceeds the imbalance limit, although the T1 service does have a provision for imbalance limits to be imposed if Epic Energy is able to demonstrate that it is adversely impacted by excessive imbalance excursions. In addition, Epic Energy has the right to interrupt users that operate outside the ±8% imbalance limits. AlintaGas submits that these arrangements are appropriate and should be maintained.

Epic Energy is proposing imbalance limits of ±2% with the imposition of penalties when the limits are exceeded. These limits appear to be excessively stringent. AlintaGas does not believe users will be able to maintain a balance within these limits and as a result users will regularly be paying imbalance surcharges to Epic Energy. The imposition of tight imbalance limits will provide Epic Energy with additional revenue at no risk to Epic Energy.

AlintaGas asks the Regulator to scrutinise historical imbalance records that are available to users via Epic Energy's electronic bulletin board. The records show that a number of users

exceed the existing ±8% imbalance limits on a regular basis, suggesting that it will be almost impossible for users to balance within a ±2% limit.

The low imbalance limit and excessive surcharges proposed by Epic Energy means users will likely be forced to negotiate arrangements with producers to mitigate the impact of the proposed imbalance regime. This is unreasonable and adds unnecessary costs to the delivery of gas given that imbalances are more easily managed within the DBNGP.

AlintaGas submits that it should certainly be explicitly stated in the proposed Terms and Conditions that users may swap imbalances with each other, as is presently the case under the GTRs (see regulation 192) and the 1998 Regime (see clause 135 of the *DBNGP Access Manual*). This will provide users with some ability to mitigate their imbalances. AlintaGas suggests there are no credible operational grounds for Epic Energy to oppose this proposal.

Epic Energy's proposed imbalance regime might also result in a double penalty from a single imbalance excursion. This is because at the start of a gas day, a user will carry-over its previous gas day's imbalance and which will therefore contribute to the current gas day's imbalance. If the user incurred a penalty for an imbalance on the previous gas day, the user may incur a second penalty on the following gas day due to the user being unaware of the previous gas day's imbalance until after nominations for the current gas day have been made.

Epic Energy requires, in clause 3.5(a) of the proposed Terms and Conditions, a user to maintain the delivery of gas at Receipt Points within its total contracted capacity. As such, a user will have difficulty returning a negative imbalance to zero and meet its contractual obligations since to do so is likely to require the user to exceed its contracted capacity at the Receipt Points. AlintaGas submits this issue should be addressed.

6.6.2 Hourly peaking limits

AlintaGas submits that Epic Energy's proposed hourly peaking limits are onerous because they are to be imposed on individual Delivery Points. AlintaGas submits that the approach adopted in the T1 service and ratified by the Gas Transmission Consultation Committee should be maintained. The approach permits a user to aggregate hourly peaks across all of the user's Delivery Points. The T1 service also provides for increased peaking allowances in winter, which AlintaGas submits should be maintained given the greater flexibility of the DBNGP in winter because of temperature re-rating effects.

Of significant concern to AlintaGas is the lack of available historical hourly data from Epic Energy, which makes it impossible to assess the impact of Epic Energy's proposals.

6.7 The zonal system is unnecessary and arbitrary

AlintaGas submits that there is no justification for Epic Energy's proposed zonal system downstream of compressor station 9. AlintaGas suggests that the T1 service of distance related tariffs and a full-haul postage stamp tariff downstream of compressor station 9 should be maintained.

The zonal system will mean, for example, that a bakery in one metropolitan suburb will be subject to a headline tariff of $1.00 per GJ, whereas the baker's competitor, still in the metropolitan area, could be subject to a headline tariff of $1.08 per GJ. This seems to be iniquitous. The proposed zonal boundary of Kwinana could have the effect of inducing small

to medium sized industries to relocate away from the Kwinana industrial areas to areas closer to the city with consequential adverse environmental impacts.

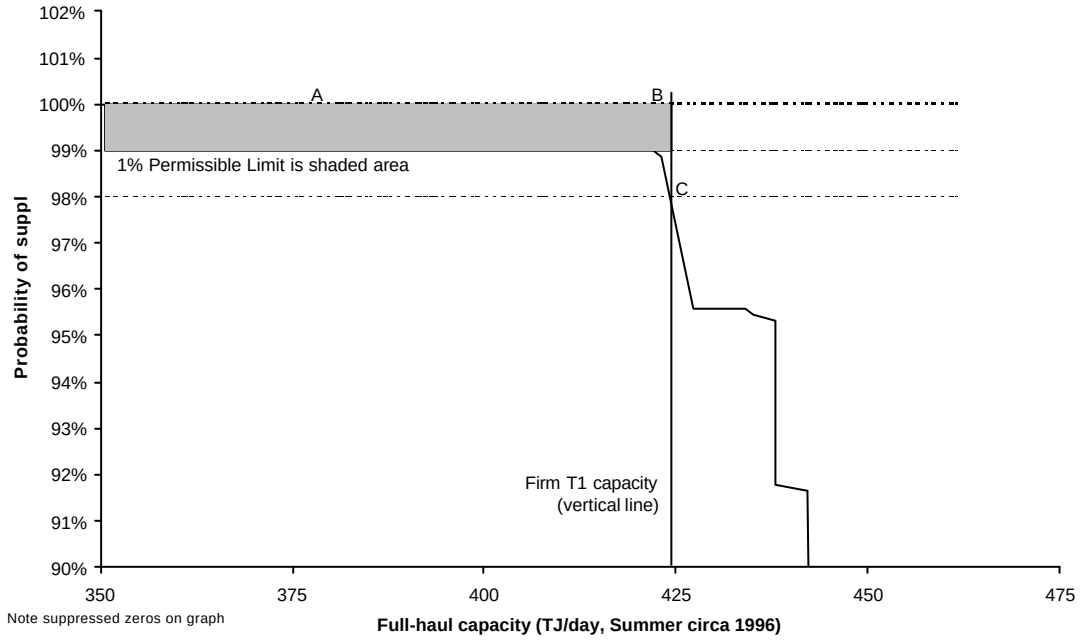
AlintaGas submits that the proposed definition of zonal boundaries is inconsistent. Most of the boundaries are 1km downstream of the relevant compressor station, except for the zone 10 boundary. It would appear that the zone 10 boundary has been chosen purely to capture the majority of the metropolitan gas demand, which occurs around Kwinana.

AlintaGas submits that Epic Energy's proposed zonal system will not promote the competitive use of natural gas in the South-West of the State.

6.8 The Permissible Limit is excessive

Epic Energy is proposing a Permissible Limit of 1% of total contracted capacity during a year. This excludes periods of force majeure. AlintaGas submits that the 1% Permissible Limit is excessive and inappropriate.

The graph below shows the probability of supply for full-haul summer capacity on the DBNGP as the pipeline was configured around the summer of 1996. The data is from a report by Tenneco Energy International (now Epic Energy) in November 1996, titled "*A Study of the Dampier to Bunbury Natural Gas Pipeline*" (the **"Tenneco Report"**). The graph is a conservative one, since it shows the probability of supply without the implementation of recommendations in the Tenneco Report designed to improve the reliability of the DBNGP. AlintaGas does not have access to more up-to-date information.



The rectangular shaded area in the graph shows capacity that Epic Energy proposes may be curtailed as part of the 1% Permissible Limit. As the graph shows, a substantial portion of the capacity that may be curtailed can be expected to be available.

In comparison, Epic Energy's curtailment rights in the existing T1 service are based on a reliability of supply of 98%. AlintaGas is confident that, under the GTRs, the total quantity of capacity curtailed will be limited to the area bounded by points A, B and C in the above graph. This provides for an overall reliability of supply above 99.9%. To AlintaGas's

knowledge, the curtailment provision has not been required since the GTRs came into effect at the beginning of 1995.

AlintaGas submits that the curtailment provisions proposed by Epic Energy are excessive and do not reflect the fair and reasonable reliability expectations for users of a "firm" service on the DBNGP. AlintaGas submits that having a 1% Permissible Limit will provide Epic Energy with the opportunity to sell more capacity as Firm Capacity. This can be seen from the above graph. As the vertical line is shifted to the right, more capacity becomes available, albeit capacity with a low probability of supply. Since the 1% Permissible Limit, as represented by the shaded area, is so generous, Epic Energy will be able to sell the less reliable capacity as firm capacity and Epic Energy will still be able to meet its contractual commitments.

The consequences for industry of Epic Energy's curtailment proposals would be unacceptable. It means that for about 3 days each year users will not be able to guarantee the delivery of gas to their customers.

Users rely on the availability of gas and pay for a firm transportation service. AlintaGas submits that the only reason capacity should not be available is during events of force majeure and to allow Epic Energy to undertake necessary maintenance at individual Delivery Points. In the case of maintenance outages, Epic Energy should be obliged to coordinate the planned outage with the user, as is required under the T1 service, by agreeing a mutually acceptable period for the outage. This will give the user some scope to make alternative arrangements, to stockpile inventory and to arrange maintenance on its own plant, as appropriate.

Epic Energy's proposed Access Contract Terms and Conditions specifies that the user must continue to pay Capacity Charges if there is an interruption due to an event of force majeure. There is no such clause associated with the Permissible Limit, so AlintaGas considers it reasonable to assume that a user is exempted from paying Capacity Charges during a Permissible Limit outage. However, AlintaGas submits that the position should be clarified.

6.9 Epic Energy's demand forecasts are conservative

Epic Energy, in determining an appropriate tariff, is forecasting that no additional capacity will be contracted during the 5-year Access Arrangement Period. Thus, Epic Energy will recover all of its revenue requirements from its contracts with existing users.

AlintaGas submits that such a demand forecast is extremely conservative. There is very little, if any, down-side. However, any increase in demand will provide Epic Energy with a windfall gain.

AlintaGas requests the Regulator to review Epic Energy's demand forecasts to ensure they are fair and reasonable and, whilst providing Epic Energy with incentives to increase DBNGP throughput, do not disadvantage users.

DEFINITIONS

"1998 Regime" means the *Dampier to Bunbury Pipeline Regulations 1998* and the *DBNGP Access Manual* dated 10 March 1998;

"AIF" means the Australian Infrastructure Fund;

"Brattle Report" means a report by the Brattle Group contained in Appendix 2 of the proposed Access Arrangement Information;

"DAC" means depreciated actual cost;

"DBNGP" means the Dampier to Bunbury Natural Gas Pipeline;

"DBNGP Issues Paper" means the Regulator's *Issues Paper to Assist with Submissions on the Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline* dated January 2000;

"DORC" means depreciated optimised replacement cost;

"FERC" means the Federal Energy Regulatory Commission (of the United States);

"GST" means the Goods and Services Tax to be introduced on 1 July 2000;

"GTRs" means the *Gas Transmission Regulations 1994*;

"Hastings" means Hastings Fund Management Limited;

"IPART" means the NSW Independent Pricing and Regulatory Tribunal;

"ORC" means optimised replacement cost;

"SAIPAR" means the South Australian Independent Pricing and Access Regulator;

"Tenneco Report" means a report by Tenneco Energy International (now Epic Energy) in November 1996, titled *"A Study of the Dampier to Bunbury Natural Gas Pipeline"*;

"T1 service" means the existing T1 service Epic Energy currently provides to users under contracts entered into under the GTRs and the 1998 Regime; and

"WACC" means Weighted Average Cost of Capital.

All currency values in the Submission are in Australian dollars.