Final Approval

Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System

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Commissioners:
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Executive Summary

Background

On 1 April 1999 the Commission received an application from Epic Energy South Australia Pty Limited (Epic) for approval of a proposed access arrangement for its Moomba to Adelaide Pipeline System (MAPS).

The MAPS is a gas transmission system owned and operated by Epic. The system connects the Cooper Basin production and processing facilities at Moomba to markets for natural gas in Adelaide and in regional centres.

The application was submitted under section 2.2 of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code). The access arrangement describes the terms and conditions on which the company proposes to make available access to services over its Pipeline System.

This *Final Approval* is the conclusion of the Commission's assessment of Epic's proposed access arrangement. The purpose of the document is to determine whether the revised access arrangement complies with the Commission's *Final Decision*, released 12 September 2001. Section 2.19 of the Code provides that in assessing the revised access arrangement, the Commission must consider whether it either:

- substantially incorporates the amendments specified in the *Final Decision*; or
- otherwise satisfies the Commission's reasoning for requiring those amendments.

Epic's revised access arrangement does not substantially incorporate the amendments required. Therefore the Commission does not approve Epic's revised access arrangement and has drafted and approved its own access arrangement for the MAPS. The reasons for this decision are outlined below.

Assessment of the revised access arrangement

Epic has incorporated a large number of the amendments required by the *Final Decision* or has otherwise addressed the Commission's reasoning for requiring those amendments.

However, there are a number of amendments which Epic has not complied with and has not otherwise addressed the Commission's concerns. These amendments are discussed below.

Initial Capital Base

In its *Final Decision* the Commission required Epic to set the value of the initial capital base to $353.3 million at 30 June 2001. Epic lodged submissions arguing that the initial capital base proposed in its access arrangement of 22 January 2002 complies with the Code. Further, Epic submitted that the initial capital base set by the Commission is at the low end of the range, largely because it does not include a contingency for omissions.

There are a range of values which would comply with the requirements of the Code. After assessing Epic's submissions, the Commission has formed the view that the initial capital base set by Epic is outside that. Accordingly, the Commission has set the initial capital base at $360.4 million at 1 January 2001. This differs to the initial capital base set in the *Final Decision* for the reasons outlined in section 2.3.1 of this document.

Working Capital

The *Final Decision* required that Epic not include the working capital component in the value of the initial capital base. However, Epic retained the working capital component in its capital base.

As stated in the *Final Decision*, the Commission believes that Epic already receives an advantage as a result of the time value of money under the Commission's cash flow modelling that is significantly greater than working capital cost. Further, the modelling of cash flows on an annual basis results in reduced administration and compliance costs while adding to the transparency of regulation.

For this reason, the Commission has not allowed the inclusion of working capital in the value of the capital base.

Asset Beta

The *Final Decision* required that Epic adopt an asset beta of 0.5 in the access arrangement. Epic has not incorporated this amendment and has retained an asset beta of 0.58.

In light of Epic's submissions in relation to the asset beta, the Commission has reassessed this issue. Following its analysis, the Commission considers that an asset beta of 0.5 is at the top end of the plausible range and therefore 0.58 does not comply with the Code. Accordingly, the asset beta has been set at 0.5.

Tariff Setting

The methodology adopted by Epic to determine tariffs was consistent with the *Final Decision*. However, the input figures were not as specified in the *Final Decision* as a result of Epic's non-compliance with a number of amendments. Accordingly, tariffs have been recalculated and are set out in Schedule B of the access arrangement.

Expansions Policy

The *Final Decision* required Epic to amend its expansions policy to the effect that all new facilities (except for extensions) would be covered unless the Regulator consented otherwise. The Commission also required that a recent expansion of the MAPS (the Pelican Point Power expansion) be covered from the time the access arrangement took effect.

The Commission has amended clause 10.10(b) of the access arrangement so that it complies with the *Final Decision*.

Commission Access Arrangement

Section 2.20(a) of the Code provides that if the Regulator does not approve the revised access arrangement it must draft and approve its own access arrangement. A proposed access arrangement has been drafted and is attached.

In drafting its access arrangement, the Commission has sought to maintain the access arrangement as proposed by Epic as much as possible. Only those changes to the access arrangement that are required to comply with the *Final Decision* have been made. The document retains the same structure and content (subject to the Commission's amendments) as Epic's revised access arrangement.

Final Approval

For the reasons expressed in this document and the *Final Decision*, the Commission has decided to approve its own access arrangement for the MAPS under section 2.20(a) of the Code.

1. Background

On 1 April 1999 the Commission received an application from Epic Energy South Australia Pty Limited (Epic) for approval of a proposed access arrangement for its Moomba to Adelaide Pipeline System (MAPS).

The Commission issued a *Draft Decision* on 16 August 2000 and a *Final Decision* on 12 September 2001 in relation to the proposed access arrangement. This *Final Approval* is an assessment of Epic's revised access arrangement to determine whether it complies with the *Final Decision*.

The MAPS is a gas transmission system owned and operated by Epic. The system connects the Cooper Basin production and processing facilities at Moomba to markets for natural gas in Adelaide and regional centres. These include Port Pirie, Whyalla, and Angaston which are connected to the main pipeline via laterals. The Pipeline System is described in clause 2 of the access arrangement.

The application was submitted under section 2.2 of the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code). The access arrangement describes the terms and conditions on which the company proposes to make access available to services over its Pipeline System.

1.1 Code Criteria

On 22 January 2002 Epic submitted its revised access arrangement and submissions (pursuant to section 2.18 of the Code) to the Commission.

Under section 2.19 of the Code if the service provider submits a revised access arrangement in response to the Commission's *Final Decision*, the Commission must issue a further final decision. This *Final Approval* is the Commission's further final decision. It is an assessment of Epic's revised access arrangement to determine whether it complies with the *Final Decision*.

Section 2.19 of the Code also provides that in assessing the revised access arrangement, the Commission must consider whether it either:

- substantially incorporates the amendments specified in the *Final Decision*; or
- otherwise satisfies the Commission's reasoning for requiring those amendments.

1.2 Assessment Process

The Commission's assessment of the access arrangement has been conducted in accordance with the requirements set out in the Code and has been based on information provided by Epic, its advisers and other interested parties. The assessment process is outlined in detail in the *Final Decision*. The assessment process since the release of the *Final Decision* is summarised below.

- On 12 September 2001 the Commission released its *Final Decision* which required Epic to make significant changes to its proposed access arrangement. Epic was required to submit a revised access arrangement by 30 November 2001.
- Following a request from Epic, the Commission agreed to an extension of the revised access arrangement submission date to 18 January 2002.
- The Commission subsequently agreed to Epic's request for a further extension to 22 January 2002.
- Epic submitted a revised access arrangement and submissions on 22 January 2002.
- On 26 March 2002 Epic lodged a confidential submission with the Commission relating to insurance issues.
- On 16 April 2001 the Commission responded to Epic's insurance submission. The Commission requested further information including the quantification of the costs involved be supplied within 6 weeks.
- On 31 May 2002 Epic wrote to the Commission indicating that it had not been able to provide the information within the six week period and stated that the information would be forthcoming within one week.
- On 2 July 2002 Epic lodged a submission on what it termed as 'Code compliance'. The subject being the weighting provided by the Commission to aspects of the Code as part of its process for assessing proposed access arrangements. In that submission Epic advised the Commission that it did not intend to provide the additional information relating to the insurance issues.

1.2.1 Insurance Submission

Epic's 26 March 2002 submission on insurance raised a number of new issues two months after the lodgement of the revised access arrangement and during the final stages of the Commission's assessment process. However, the submission has been accepted for the following reasons:

- section 2.28 of the Code allows for proposed revisions to an access arrangement to be submitted at any time. Accordingly, Epic could utilise this mechanism to have the insurance issue considered if the Commission did not assess this issue prior to the release of the *Final Approval*; and
- a number of Epic's key insurance policies expired at the end of 2001, and therefore the insurance issues only became apparent following the release of the *Final Decision* on 12 September 2001.

The Commission considers that it is appropriate in these circumstances to consider the insurance issue as part of the *Final Approval*.

1.3 Documents

The Commission's *Final Decision* on Epic's proposed access arrangement detailed the Commission's analysis of the proposed access arrangements, the amendments required in order for approval to be granted, and its reasons for requiring those amendments. The *Final Approval* sets out the Commission's assessment of the revised access arrangements submitted by Epic in response to the *Final Decision*. Consequently the two documents should be read together.

Copies of the Commission's decision documents are available on the internet site (http://www.accc.gov.au) under 'gas'.

2. Assessment of revised access arrangement

2.1 Code Compliance

Epic's submissions

In response to the Commission's *Final Decision*, Epic has lodged a number of submissions. Final Decision Submission #4 (FDS4), received on 2 July 2002, specifically considers the issue of the Commission's compliance with the Code in assessing Epic's access arrangement. The company's position is that the Commission has failed to properly interpret and apply the provisions of the Code.

Epic submits that the factors set out in section 2.24 of the Code are paramount and overriding factors and should be provided fundamental significance by regulators in assessing access arrangements.[1] Epic submits further that the Commission has given no or less consideration to the section 2.24 factors in its *Final Decision* than should have been given. As a result, according to Epic, the validity of the *Final Decision* is questionable.

Epic argues that the Commission's failure to properly consider the factors set out in section 2.24 of the Code is demonstrated by the following:

- neither the *Final Decision* nor the *Draft Decision* contain a detailed assessment of the section 2.24 factors;
- the discussion of Epic's proposed reference tariff policy in the *Final Decision* explicitly referred to the principles and methodologies set out in section 8 of the Code but not to the section 2.24 factors;
- the Commission comments in the *Final Decision* that its principle role is the regulation of market power; and
- the nature of a number of the amendments required.

Epic is critical of the Commission's approach to assessing access arrangements, claiming that the regulator sees only one way of an arrangement complying with the Code. Epic contends that there are a variety of ways in which the principles and elements of the Code can be met, and it is the role of the Commission to assess whether the service provider's proposal is reasonable.

1 Epic Energy FDS4, 1 July 2002, p.3.

Commission's considerations

Section 2.24 of the Code provides that the Commission must take into account a number of factors in assessing a proposed access arrangement. Those factors are as follows:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(e) the interests of users and prospective users; and

(f) any other matter that the Relevant Regulator considers relevant.

The Commission agrees that all aspects of an access arrangement must be considered in light of the factors set out in section 2.24 of the Code. While the *Draft* and *Final Decisions* do not contain lengthy discussions of this section, the Commission did consider the factors set out in section 2.24, albeit implicitly in some sections. By way of example, in its consideration of the submissions from both users and the service provider, the Commission took into account the interests of those parties and in doing so demonstrates compliance with the Code's requirement under section 2.24.

Not all of the section 2.24 factors will have equal relevance to all provisions of the access arrangement. Accordingly, the Commission does not believe that it must provide detailed consideration of each of the factors set out in section 2.24, in relation to every provision of the access arrangement and consequently, has not done so. Consideration was given to relevant factors to the issue at hand and where appropriate an explicit discussion was included.

Epic argues that another example of the Commission's failure to take into account the section 2.24 factors was a statement in the *Final Decision* that the Commission's principal role as regulator of gas pipelines is to mitigate the effects of market power.

In response the Commission notes the full context within which this comment was made. In the *Final Decision* the statement is qualified by a prior comment that the Commission must balance the interests of users and the service provider, and a subsequent statement that the Commission must provide a fair return to the service provider which is sufficient to encourage new investment. When read in context, these statements indicate that the Commission has sought to balance the factors set out in section 2.24 in assessing Epic's proposed access arrangement.

The Commission is in full agreement with Epic's submission that there are a variety of ways in which an access arrangement can satisfy the Code. The Commission is of the opinion that the Code provides a reasonable degree of flexibility and a range of outcomes are consistent with it. However, where an amendment was required in the *Final Decision*, it was because Epic's proposal was not within the range of outcomes consistent with the Code.

In conclusion, it is the Commission's position that it has not misinterpreted the Code in its assessment of Epic's proposed access arrangement. Therefore the *Final Decision* is a valid decision.

Epic made submissions on a number of aspects of the *Final Decision*. Those relevant will be discussed in subsequent sections. However the Final Approval will not discuss submissions on the following:

- provisions of the access arrangement proposed by Epic with which the Commission has not required any amendments; and
- amendments required in the *Final Decision* that Epic has complied with.

The Commission has not discussed the above aspects of FDS4 because they are not relevant to this document, which assesses Epic's revised access arrangement to determine whether it incorporates the amendments set out in the *Final Decision*.

2.2 Amendments incorporated fully

The Commission notes that Epic has incorporated a number of the required amendments fully into its revised access arrangement and no further comment is necessary. The Commission is satisfied that the following amendments have been complied with:

- FDA3.5 is incorporated into clause 9.3;
- FDA3.6 is incorporated into clause (a)(i) of Schedule 1;
- FDA3.7 is incorporated into clause (a)(ii) of Schedule 2;
- FDA3.12 is incorporated into clause 17.3(e);
- FDA3.13 is incorporated into clause 17.3(f);
- FDA3.15 is incorporated into clause 19.1;
- FDA3.18 is incorporated into clause 19.3(c);
- FDA3.20 is incorporated into clause 19.5;
- FDA3.21 is incorporated into clause 19.7;
- FDA3.23 is incorporated into clause 23.3;
- FDA3.26 is incorporated into clause 27.1(b);
- FDA3.27 is incorporated into clauses 28.1(i) and 28.2(i);
- FDA3.28 is incorporated into clause 34.1(a);
- FDA3.30 is incorporated into clauses 37.1(d) and 37.2(h);
- FDA3.31 is incorporated into clause 40;
- FDA3.32 is incorporated into clause 26.6(a)(iv); and

- FDA3.36 is incorporated into clause 10.1(b).

2.3 Amendments requiring further consideration

Listed below are the remaining amendments set out by the Commission in the *Final Decision*. Under each, the Commission has assessed whether the revised access arrangement substantially incorporates the amendments required, or whether the Commission's concerns have been otherwise addressed by Epic.

2.3.1 Initial Capital Base

Amendment FDA2.1

For the access arrangement to be approved, the Commission requires the value of the initial capital base to be set to the value derived by the Commission, $353.3 million at 30 June 2001.

Implementation of amendment in revised access arrangement

The value of the initial capital base has been set by Epic at $423 million in 2001 dollars in its revised access arrangement.[2]

In Final Decision Submission #5 (FDS5), provided on 22 January 2002, Epic provided two reasons for not adopting the specified value of the initial capital base:[3]

- Epic does not agree with the methodology used by the Commission to determine the Depreciated Optimised Replacement Cost (DORC) value for the Initial Capital Base and believes that its value is consistent with the Code's requirements in this respect; and
- Epic does not agree that the National Power (now Pelican Point Power) Expansion can be included as part of the covered pipeline and therefore associated costs should not be included in the capital base calculations.

In relation to the first point, Epic employed the same model used by the Commission to depreciate the optimised replacement cost (ORC).[4] Therefore, the differences between the DORC calculations of Epic and the Commission arise in the calculation of ORC. These differences are discussed below.

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2 Revised Access Arrangement Information for the MAPS, 22 January 2002, Attachment 1, p.19.

3 Epic Energy FDS5, 22 January 2002, section 2.1.3.

4 While it could be interpreted from FDS5 that Epic does not concur with the Commission's approach to calculating DORC, discussions with Epic's consultant (John Williams of KPMG) on 19 March 2002 revealed that Epic applied an identical methodology for calculating DORC from ORC. That is, the differences between the two DORC estimates stem from different assumptions in calculating ORC. Despite Epic's use of the Commission's depreciation methodology, however, Epic states in paragraph 6.29 of FDS4 that they have adopted a different approach to developing their estimate of the initial capital base. However, the approach described is inconsistent with the approach used in arriving at a DORC value of $423 million in 2001 dollars as stated on page 10 of the revised access arrangement information.

Epic also indicated that it would elaborate on the arguments presented in FDS5 in a future submission to be titled ‘Code Compliance’. The Commission received Epic’s Final Decision Submission #4, Code Compliance (FDS4) on 2 July 2002. Paragraphs 6.27 through to 6.91 of this document contain Epic’s explanation and arguments in support of its initial capital base. While there is some inconsistency between what Epic proposed in FDS4 and what Epic has implemented in its revised access arrangement and access arrangement information with respect to calculating DORC from ORC and the final figure assigned to DORC, most of Epic’s arguments in FDS4 relate to the ORC calculation. Epic’s arguments in FDS4 are summarised as follows:

- the Commission’s estimate of ORC is at the low end of the range of costs for a new pipeline, largely as a result of an insufficient allowance for costs not included in the unit materials and construction costs, and the absence of a contingency allowance to account for these omissions;
- Epic’s estimates for valuing the MAPS are reasonable because they are supported by actual costs of constructing similar pipelines;
- the Commission has been inconsistent in its approach when compared with other decisions; and
- the Commission’s use of unit costs at the lower bound of the commercial range is an unreasonable approach.

In addition, Epic modified its approach to calculating interest during construction in its lodgement of 22 January 2002.

Commission’s assessment of revision for compliance with required amendment

There is a significant difference between the Commission’s amendment FDA2.1 and Epic’s initial capital base set out in its access arrangement information of 22 January 2002. Epic acknowledges that it has not complied expressly with the amendment set out in the *Final Decision*, but maintains that the value it adopted for the initial capital base does comply with the Code.

After receiving Epic’s revised access arrangement, access arrangement information and supporting submissions, the Commission examined the reasons for the differences between its DORC value and the value adopted by Epic. Following this analysis, the Commission disagrees that Epic’s proposed initial capital base complies with the requirements of the Code.

The issue of whether or not the Pelican Point Power expansion can be included as part of the covered pipeline is discussed in section 2.3.5 and section 2.3.7. However it should be noted, that if the Commission had not included the Pelican Point Power expansion, the calculation of ORC would have been lower. This would have increased the differential between Epic and the Commission. The Commission’s response to Epic’s arguments and revised ORC calculation is presented below.[5]

[5] More detailed analysis of Epic’s ORC calculation by the Commission is presented in annexure 5 to this *Final Approval*.

Contingency allowance

Epic has argued that the Commission's ORC is understated as it does not contain an allowance for contingencies and omissions. However, with regard to the Commission's estimate of ORC for the MAPS, unit rates and allowances applied in its estimate were based, where possible, on actual known or reported project costs. In the case of linepipe, unit rates were based on a consultant's report[6] on currently applicable costs.[7] As such, the rates and other allowances have been 'fine tuned' over time to ensure *total* cost estimates based on these rates align with *reported total* costs. Therefore, an explicit allowance for omissions and contingencies would involve double counting and overstate the ORC.

Reasonable costs supported by actual project outcomes

Epic has argued that its 'all in' costs are reasonable, and are supported by actual cost outcomes for similar pipeline projects.

For the MAPS mainline, Epic adopted a uniform rate of $22,000 per km for each inch in diameter (referred to as per inch km), in 1998 dollars, for all four options it presented, regardless of differences between the maximum design pressure of each option.[8] Epic partly addressed the insensitivity of its 'all in' unit rate to varying design pressure conditions by increasing the unit rate. However, this was only for lateral pipelines and only for Option B, which has the highest design pressure rating (15MPa) of all the options considered.

The Commission does not consider that Epic has demonstrated that this approach is either reasonable or supported by actual project outcomes.

Consistency with other decisions

Epic appears to infer in the following statement that the Commission has not been consistent by allowing a higher 'all in' rate in the case of its EAPL Moomba to Sydney Pipeline (MSP) *Draft Decision*:[9]

> It is noted that the Commission's draft decision for the EAPL Moomba to Wilton pipeline values the ORC of that pipeline at $748.7 million (in 1999 dollars), or an "all in" cost of $30,170 per inch km (including development and owner's costs). This pipeline is a similar design (DN600, Class 900, 1034 km long compared with the Epic Energy 780 km DN 550 Class 900 MAPS).

Comparisons of the cost of different pipeline projects based on unit rates are unreliable given the variables affecting project outcomes.[10] Limitations of the comparison methodology aside, Epic's conclusions are incorrect.

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6 MicroAlloying International: *Report on Pricing of High Strength Linepipe*; 7 December 2000.

7 In addition, as set out in annexure 5 to this *Final Approval*, the model used by the Commission includes a 2.5% increment in determining quantities for linepipe (given that additional pipe is normally ordered to allow for any damage, errors in survey and minor route changes), coating and delivery costs.

8 Epic Energy Moomba to Adelaide natural gas pipeline: Analysis of optimised replacement cost for pipeline system and facilities; Revised Access Arrangement Information; 22 January 2002, p.30.

9 Epic Energy FDS4, 2 July 2002, p.36.

Epic's statement contains a number of errors. The equivalent 'all in' cost of the optimised Moomba to Wilton pipeline (without the contingency but including development and owner's costs) is $821.6 million[11] in 1999 dollars. The optimised Moomba to Wilton pipeline is 1,299 km in length. The correct equivalent 'all in' unit rate is $26,350 per inch km (or $28,828 per inch km after conversion to 2001 dollars).

The Commission's equivalent 'all in' rate for the MAPS Option D is $29,633 per inch km in 2001 dollars, for a lower pressure Class 600 pipeline option.

Reasonableness of lowest unit costs commercially offered

Epic argued that the Commission has been unreasonable in adopting costs at the lower bound of the range, and that there are often commercially sound reasons for not adopting the lowest cost offer. Firstly, it is worth distinguishing between estimated costs and observed costs. In many instances, the Commission's cost estimates have actually been higher than Epic's. The Commission understands that Epic's arguments arise predominantly in the case of the cost of pipe. The pipe cost is significant in the total ORC calculation (approximately 30 percent before interest during construction) and therefore, a crucial input.

Given the importance of this input to the calculation of ORC, the Commission engaged MicroAlloying International to provide the Commission with observed commercial prices for *suitable* pipeline steel. In this instance, the Commission adopted prices at the lower bound of the commercially offered prices for pipe[12] as there was a reasonable degree of certainty involved. Epic has argued that some of the lower range costs reported by MicroAlloying would require an additional component for quality inspection. However, even if inspection was required for the observed prices reported by MicroAlloying International, such costs would be immaterial given the magnitude of the total pipe cost and therefore unlikely to affect the outcome.

The Commission considers that such a choice would also be the choice adopted by a reasonable and prudent service provider.

Interest during construction

Epic's original access arrangement was based on a construction period of 18 months, and financing based on a debt to equity ratio of 90/10. Epic's revised ORC calculation assumed a construction period of 24 months and financing based on a debt to equity ratio of 60/40. The required rate of return on debt and equity were 7.2 and 15 percent respectively.

Epic provided no justification for its shift to the assumption of a construction period of 24 months in its latest lodgement. In the absence of reasonable supporting evidence for Epic's latest position, the Commission considers it appropriate to continue to adopt a construction period of 18 months, as originally proposed by Epic, which is considered reasonable provided efficient project management is employed.

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10 See for example the discussion on this topic in GPU Gasnet: Application for Revision to Access Arrangement Southwest pipeline; September 2000, annexure 5, p.39.

11 ACCC: *Draft Decision* EAPL MSP, December 2000, Table 2.2, p.29.

12 Only pipe meeting the well known API 5LX standard was considered.

In its previous ORC assessments, the Commission has based the required rate of return on 100 percent debt funding (at a rate of 6.68 percent for the MAPS *Final Decision*). The Commission has reconsidered its position on this issue. While in practice 100 percent debt finance during construction is not uncommon, the Commission has decided to use its calculation of the nominal vanilla WACC as the required rate of return, which assumes a 60/40 debt to equity ratio. This approach is consistent with the Commission overall assumption of a stand-alone pipeline service provider as the regulated entity, and was also supported by Davis and Handley in a recent report prepared for the Commission.[13]

The Commission's use of the nominal vanilla WACC in calculating interest during construction has increased this ORC element from $29.8 million to $36.9 million. However, the Commission's calculation, is still substantially less than Epic's calculation of $57 million. This can be attributed to the shorter construction period and lower calculation of the costs of debt and equity that feed into the calculation of WACC.

Conclusion

Following examination of Epic's revised proposal, the Commission concludes that it does not meet the requirements of section 8.10 or section 2.24 of the Code. The Commission considers that Epic's ORC calculation leads to an unreasonably high initial capital base and therefore does not represent international best practice of pipelines in comparable situations, as required under section 8.10 of the Code. In addition, the Commission considers that it would have a negative impact on the competitiveness generally of energy consuming industries, and on the economically efficient utilisation of gas resources.[14] Further, the Commission considers that Epic's proposed initial capital base does not represent a fair balance of the factors listed under section 2.24 of the Code, particularly the interests of users and prospective users. The ORC calculated by the Commission is reasonable and thereby incorporates the legitimate business interests of the service provider in addition to the interests of users and prospective users.

For the reasons listed above, the Commission has rejected Epic's proposed initial capital base and has adopted its own ORC calculation as set out in the *Final Decision* with an adjustment to the treatment of interest during construction in Epic's favour. This results in an ORC value of $632 million at 30 June 2001. Using the same methodology as Epic to depreciate the ORC, the Commission has determined a DORC of $358.9 million at 30 June 2001, and for modelling purposes a value at 1 January 2001 of $360.4 million. The initial capital base value at 1 January 2001 is therefore, set at $360.4 million. This value is reflected in schedule A of the attached Access Arrangement and is used to determine the revenue requirement and tariffs, which are provided in schedule B.

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13 Kevin Davis and John Handley, *A report on Cost of Capital for Greenfields Investments in Pipelines,* April 2002, p.21.

14 Section 8.10 of the Code requires the Commission to consider these issues.

2.3.2 Working Capital

Amendment FDA2.2

For the access arrangement to be approved, the Commission requires that the working capital component not be included in the value of the capital base for the purpose of calculating Epic's capital charge (return on capital assets).

Implementation of amendment in revised access arrangement

The working capital component remains in the capital base calculation as originally proposed by Epic.

Epic provided the following definition of working capital:[15]

> …the average amount of capital provided by investors…over and above the investment in plant…required to bridge the gap between the time that expenditures are required to provide service and the time collections are received for that service.

Working capital has been calculated by Epic as 20 days of the annual managed costs.[16]

Epic argues that working capital is required to be included as a component of the capital base because at the time Epic acquired the MAPS, there was an initial period during which payments were required in advance of revenue being received. Working capital was required in order to cover those payments. Consequently, Epic argues that an allowance for the opportunity cost associated with working capital (commonly measured as interest expense) should be incorporated into the calculation for target revenue, irrespective of the timing of subsequent receipts and payments.[17]

Prior to the release of the *Final Decision*, Epic submitted a document further stating its arguments for including working capital in the capital base and the return on working capital in the total revenue. This document explains the actual timing of revenue and expenses and states the costs incurred as a result.[18]

Epic re-stated its arguments again in FDS5 lodged on 22 January 2002, submitting that by not including an explicit allowance for working capital, the Commission has failed to recognise the legitimate business interests of the service provider and to consider the factors in section 2.24 of the Code. However, Epic's submission did not address the reasoning presented in the *Final Decision*, and the fact that compensation for working capital costs is implicit in the Commission modelling approach.

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15 Ohio PUC, Re Columbus Southern Power CO, 1992 133 PUR4th 525, 550, quoted by Epic in Access Arrangement Information, 5 May 1999, p. 28.

16 Revised Access Arrangement Information for the MAPS, 22 January 2002, p.10.

17 Epic Energy Response to *Draft Decision* - Part A, 10 October 2000, p.9.

18 Epic Energy FDS1, 23 August 2001, Attachment 1, p.1-2.

Commission's assessment of revision for compliance with required amendment

Amendment FDA2.2 has not been incorporated in Epic Energy's revised access arrangement.

As stated in the *Final Decision*, the Commission believes that Epic already receives an advantage as a result of the time value of money under the Commission's cash flow modelling that is significantly greater than working capital cost. In its cash flow analysis, the Commission assumes that all costs and revenues are incurred on the last day of the financial year (31 December in Epic's case). There is, however a difference between the assumed and actual timing of operational cash flows within each year resulting in a financial benefit to Epic.

The Commission's determination of required revenue under the cost of service approach centres around cash flow modelling. The cash flow model used by the Commission assumes that the service provider receives the share of revenue in respect of capital costs on the last day of the year. As revenue is received over the course of each year, it would be expected that target revenue would overstate the opportunity cost associated with investors' funds and would more than offset any shortfall in the cost of financing operating expenditure (that is, the required return on working capital).

If Epic's cash flow were modelled more precisely (such as on a monthly or a daily basis rather than annually) it would be appropriate to explicitly include the working capital component. As a result, however, the total required revenue for Epic would be less than determined under the Commission's modelling approach. Modelling cash flows on an annual basis results in reduced administration and compliance costs while adding to the transparency of regulation.

The post-tax revenue model (PTRM) depicts the Commission's cash flow modelling approach, and forecasts revenue and expenses on an annual basis. To verify and quantify the Commission's own analysis, it engaged the Allen Consulting Group to undertake more detailed analysis and to provide advice in relation to the compensation for working capital in the calculation of reference tariffs. Specifically, the Commission sought advice as to whether it is appropriate to include an allowance for working capital in the capital base, in conjunction with its application of the PTRM. The treatment of working capital is an issue that has arisen in the Commission's consideration of several access arrangements.

The consultancy report outlines a model that demonstrates the methodology employed to assess whether such an allowance is appropriate with specific application to the MAPS.[19] All information relevant to working capital, supplied to the Commission by

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[19] As described in their Working Capital report, The Allen Consulting Group built a model that demonstrates the bias existing under the various timing methodologies and permits assumptions to be entered about the actual timing of a service provider's cash flows over a test year. These assumptions are then used to allocate the expenditure and revenue over that year against particular days in the year (with some of the revenue and expenditure in respect of a year typically falling into the next year). Once a proxy for 'daily' cash flow is derived, it is possible to calculate the precise target revenue (corresponding to timing assumptions) by conducting a discounted cash flow calculation on a daily basis. Thus, to the extent that there is a difference between the timing of expenditure and the receipt of revenue, the opportunity cost associated with that delay is implicitly included in the precise target revenue, irrespective of whether the expenditure would be classified

Epic was considered during the consultancy including Epic's Final Decision Submission #1 (FDS1), which stated the actual timing of revenue and expenditure and the costs incurred as a result.

The results of the consultancy suggest that, were further precision to be sought in relation to the within-year timing of cash flow, and working capital to be explicitly compensated, then the likely outcome is that the more precise target revenue would be lower than that derived by the PTRM. Specifically, the consultancy concluded that a more precise cash flow model in conjunction with an explicit working capital component would result in a decrease of 1.8 percent of the revenue requirement.

These findings indicate that an additional or explicit allowance for working capital in target revenue is unwarranted. This is due to the favourable allowance provided to Epic owing to the timing difference under the target revenue formula adopted by the Commission.

Conclusion

The Commission's cash flow modelling errs on the side of the service provider by providing for total revenue that exceeds that which is calculated in a more precise and explicit model. Explicit compensation for working capital in conjunction with the adoption of the PTRM cash flow modelling approach would double count the working capital cost in addition to erring on the side of the service provider. This is true regardless of whether the working capital cost arises from an initial outflow at the time of pipeline acquisition or from ongoing operational timing differences between expenditure and revenue.

For this reason, the Commission will not allow the inclusion of working capital in the value of the capital base and therefore will not allow a working capital charge to be included in the revenue requirement.

2.3.3 Beta and Risk

Amendment FDA2.3

For the access arrangement to be approved, the Commission requires:

- the WACC estimates and associated parameters forming part of the access arrangement to be amended to reflect the current financial market settings, by adopting the parameters set out by the Commission in Table 2.13 and Table 2.14; and
- the target revenues and forecast revenues to be based on these new parameters.

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as operating or capital expenditure for financial accounting purposes. The precise target revenue calculation can then be compared to the target revenue derived from the simple formula (used in the PTRM) and the differences determined.

Implementation of amendment in revised access arrangement

Attachment 3 of the Revised Access Arrangement Information for the MAPS dated 22 January 2002 contains the rate of return parameters including asset beta, debt beta and equity beta (derived).

In its *Final Decision* for the MAPS, the Commission determined an asset beta of 0.50, a debt beta of 0.06, and a corresponding equity beta of 1.16. Epic complied with each of the input parameters with the exception of the asset beta, and those parameters dependent upon the asset beta. Epic adopted an asset beta of 0.58 instead of 0.50.

Epic's supporting arguments for not adopting the asset beta determined by the Commission are contained in Epic's confidential Final Decision Submission #3 (FDS3) and in FDS4. The Commission has addressed the arguments presented in confidential FDS3 in confidential annexure 3. Annexure 1 to this *Final Approval* is a public version of the Commission's response.

Epic states in FDS4 that it considers that the Commission's rate of return calculation does not reflect a proper balancing of the factors listed in section 2.24 of the Code. Epic takes particular issue with the use of the Capital Asset Pricing Model (CAPM), the values assumed for beta and the assumed utilisation of imputation credits. However, it should be noted that Epic actually proposed the use of CAPM, and complied with the *Final Decision* with respect to the assumed utilisation of imputation credits. The outstanding issues raised in FDS4 are the treatment of stranding risk, and the value assumed for beta in applying the CAPM. As previously noted, the treatment of stranding risk is primarily the subject of confidential annexure 3, while the beta to be used in the CAPM is discussed below.

Commission's assessment of revision for compliance with required amendment

Epic adopted the cost of service methodology for calculating the revenue requirement for the MAPS. A significant cost element to be included in the total cost of service is the rate of return. Epic elected to use a weighted average cost of capital (WACC) methodology, and the CAPM to determine the appropriate cost of equity to feed into the WACC calculation. The methodology employed by Epic is consistent with chapter 8 of the Code, and indeed used as an example in the Code. As noted earlier, Epic did not adopt the value for beta (the measure of non-diversifiable or systemic risk used in the CAPM) required by FDA2.3.

Each parameter feeding into the rate of return calculation, including beta, was discussed in detail in the Commission's *Draft* and *Final Decisions*,[20] and involved public consultation and several expert consultants' opinions. Prior to considering arguments around rate of return and the CAPM, it is useful to revisit the well accepted financial theory underpinning the CAPM framework.

CAPM theory and application by the Commission

Risk can be divided into two categories: systematic (non-diversifiable), and non-systematic (diversifiable) risk. Systematic risks are the market-related risks faced by an

[20] See section 2.5 of the Commission's *Final Decision* for the MAPS.

investor irrespective of the industry. Examples are the risk of political upheavals and economic up-turn or down-turn.

Compensation for systematic risk is made though the market-risk premium and beta factors found in the Capital Asset Pricing Model (CAPM). The CAPM provides compensation for systematic risk only, as firm specific risk can be eliminated through diversification. The equity beta is a statistical measure that indicates the riskiness of one asset or project relative to the whole market (usually taken to be the Australian stock market). With the market average being equal to one, an equity beta of less than one indicates that the stock has a low systematic risk relative to the market as a whole. Conversely, an equity beta of more than one indicates that the stock has a relatively high systematic risk.

Where an equity beta is calculated for a particular company, it is only applicable for the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders. Hence, the equity beta will change. It is possible to derive the beta that would apply if the firm were financed with 100 percent equity, known as the 'asset' or 'unlevered beta'. This enables comparison across companies with different capital structures. The analyst can then calculate the equivalent equity beta for any level of gearing desired, known as 're-levering' the asset beta.

Non-systematic risks are specific or unique to an asset or project and may include asset stranding, bad weather and operations risk. Such risks by their nature are specific and need to be assessed separately for each access arrangement. Importantly, non-systematic risk (specific risks) are independent of the market. For an investor, exposure to non-systematic risk related to an asset can be reduced or countered by holding a diversified portfolio of investments. Consequently, specific risk is not reflected in the equity beta parameter of the CAPM.

While other asset pricing models involving additional risk factors have been developed in the literature, the CAPM is currently still considered to be the dominant approach adopted in practice for estimating required rates of return.[21] The Commission considers that the CAPM is an appropriate framework for assessing the WACC facing natural gas transmission pipelines. The integrity of the CAPM model should be maintained in order to preserve the validity of its output. That is, it must only recognise risks of a systematic or market related nature. The Commission considers that the Code requires robust application of the relevant financial model under section 8.31 (in this case the CAPM). Accordingly, variations to the CAPM to take account of risks that are not purely of a systematic type are inappropriate. Non-systematic risks (specific risks) associated with a pipeline should not lead to an adjustment of beta – which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant bias.[22]

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[21] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002, p.21.

[22] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002, p.21.

A matter of significant debate in the Commission's assessment of the Victorian access arrangement in 1998 was the treatment of specific (diversifiable) risk. As discussed above, the equity beta is meant to reflect only market related or non-diversifiable risks. Consistency with the CAPM framework therefore requires that specific risks be factored into projected cash flows rather than the cost of capital. The Commission indicated in its *Draft Statement of Regulatory Principles* that this is the approach that the Commission will normally adopt with respect to identified and quantified specific risks[23] and has done so in subsequent decisions. This is consistent with the former Office of the Regulator General's (now the Victorian Essential Services Commission (ESC)) assessment, as stated in its first consultation paper for the 2003 review of gas access arrangements:[24]

> … while events that are unique to particular businesses do not affect the cost of capital, they are not irrelevant. Rather, the price controls should be designed to ensure that the regulated entity expects to earn its costs of capital on average, taking account of all possible events.'

Epic's submission

While Epic's primary submission relating to stranding risk and beta is confidential, most of the arguments advanced by Epic in respect of beta are already in the public domain. In summary, Epic's arguments relate to the following:

- a higher beta should be used as compensation for stranding risk;
- the strength of the Brattle Report versus the Commission's empirical analysis;
- the Commission's use of distribution entities as comparators in assessing beta; and
- precedent of the Victorian *Final Decision* in 1998.

Commission's considerations

Under section 2.24 of the Code, the Commission is required to make a determination that balances a number of factors including the legitimate interests of the service provider, existing users, potential third party access seekers and the broader public interest. The legitimate interests of the service provider include providing a rate of return that is commensurate with prevailing conditions in the market for funds and with the commercial risk associated with providing the reference service.

In summary, the Commission has concluded that an asset beta of 0.50 (and an equity beta of 1.16) is extremely generous. While at the time of the *Final Decision* the Commission considered these values to be at the top of the plausible range, recent empirical analysis of relevant listed Australian entities reveals an equity beta of less than 0.70. Each of the issues raised by Epic and further explanation of the empirical analysis noted above are discussed below.

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23 ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999, p.79.

24 Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No 1*, May 2001, p.60.

Stranding risk

As discussed above, it is well established in the finance literature that the appropriate measure of risk for determining the rate of return on a project is the systematic risk of a project and not its total risk. As noted by NERA,[25] this approach is consistent with that adopted by the Federal Energy Regulatory Commission (FERC) in the US whereby no additional allowance is made in setting the allowed rate of return for the 'risk' a pipeline service provider faces in needing to fill capacity or sign long-term contracts.

Given Epic has sought additional compensation via a higher asset beta, this is to argue that there is a positive correlation between returns on the MAPS and returns on an equivalent market portfolio. However, no evidence or view has been advanced to suggest that the stranding risk facing the MAPS is in any way related to broader market movements (systematic risk). It is the Commission's view that the stranding risk facing the MAPS is non-systematic. Therefore, to maintain the integrity of the CAPM and the validity of its output, the stranding risk faced by Epic must not be incorporated into the CAPM's risk factor, beta.[26] Rather, stranding risk must be addressed through other means.[27]

The Brattle Report

In response to Epic's use of the Brattle Group's report (the Brattle Report) to support an asset beta of 0.58, the Commission observes three major weaknesses. Firstly, while each of the five comparators have gas transmission interests, the majority of the comparators earn substantial portions of revenue from other non-regulated sources and indeed not from pipeline operations.[28] Indeed, a recent empirical study of the appropriate proxy beta[29] for Australian gas transmission pipelines did not include any of the firms used by the Brattle Group as each of them has substantial interests outside of gas transmission such as production and energy trading.[30] As stated by the ESC in its recent Draft Decision for the Victorian Gas Distributors:[31]

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25 National Economic Research Associates, Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios, October 2000.

26 If a reduction in demand is caused by market wide or systematic events, the Commission would expect to observe a higher beta. This is consistent with the findings of the Allen Report - The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.12.

27 See section 5 of annexure 1 (and confidential annexure 3) to this *Final Approval*.

28 The three year average ratio of pipeline revenues to total revenues for 1994-1996 was as follows for each of the comparators used in the Brattle Report: Coastal (30.0%), El Paso (100%), ENRON (8.7%), Sonat (32.7%) and Williams (41.5%). Figures sourced from Exhibit S-9, Schedule D, of FERC paper Koch Gateway Pipeline Company Docket no. RP97-373-000 December 1997 access via the world wide web at http://rimsweb1.ferc.gov. The Commission notes that the market has changed substantially since the time of this data, and that recent empirical work by the Allen Consulting Group did not include any of the above five companies as comparators as they did not earn enough revenue from gas pipelines.

29 A proxy beta refers to the value assumed for beta in the absence of direct observation.

30 The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, sections 4.1 and 5.2.

31 The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.235.

> …as the objective is to derive the cost of capital associated with a pure-play gas distribution business, any prospective change to the equity beta arising from diversification into other activities would be introducing irrelevant information.

The Commission considers that this principle would apply equally to estimating a proxy beta for gas transmission pipelines. Therefore, the Brattle Report's recommended asset beta is not relevant to the MAPS, as the firms selected for comparison derive revenue and hold assets that vary greatly to that of the MAPS.

Secondly, while a key feature of the Brattle Report involved a re-weighting of the US market to make it more reflective of the Australian market, it is unlikely that this is the only adjustment required to make an accurate international comparison. The Commission noted in the *Final Decision* that international comparisons are complex, and is of the view that there is insufficient evidence to suggest that re-weighting the market indices is sufficient to be able to compare like with like.

As part of the Commission's review of the Victorian gas access arrangements in 2002, The Allen Consulting Group was engaged by the Commission to undertake empirical research into the appropriate proxy beta to apply to Australian gas transmission pipelines. The Allen Consulting Group was also asked to examine the existing studies on this topic including the NECG Report commissioned by GasNet and the Brattle Report. The Allen Consulting Group's report (the Allen Report) makes the following comment with respect to the Brattle Group's adjustment to the US market to resemble the Australian market:[32]

> … the Brattle Group's adjustment of the US market to resemble Australia is considered a valid attempt to correct for the impact of market weights.
>
> That said, it is impossible to know the accuracy of the adjustment for the difference in market weights. The sectors that the Brattle Group had regard to were broad industry groupings, and the composition of the industry groupings may vary substantially between Australia and the US. Accordingly, the adjustment for the change in market weights can only be considered an approximation. Moreover, the Brattle Group Report did not include estimates of equity betas for its comparable entities measured against the US stock market (using the same time period of observations). Accordingly, the impact of the change in market weights alone cannot be identified.
>
> In addition, the impact of weights of the various market sectors is only one of the factors that may cause the beta for the same project to vary depending upon the country in which it is situated. Another factor is the sensitivity of asset prices in any market to macroeconomic shocks within that particular market, which will depend upon a number of matters, such as institutional factors and government policies. Accordingly, it is considered that these estimates should remain a secondary source of information, with primary regard to be had to evidence from the Australian market.

The Commission's third issue with the Brattle Report relates to the fact that the primary information that should be used to develop a proxy beta should be of the same country of origin as the entity for which the proxy is being developed. This is consistent with the view that a proxy beta must be assessed by comparing like with like to the extent possible, and that there are numerous and substantial differences in beta values

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[32] The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.57-58.

internationally. The Commission again concurs with the position of the ESC in its *Draft Decision* for the Victorian Gas Distributors, that given the difficulties associated with international comparisons, the primary source of information should be from domestic entities. An extract from the ESC's *Draft Decision* is presented below:[33]

> In its previous decisions, the Commission has had regard to estimates of betas for overseas firms (measured against their home share markets) as a secondary source of information, although it has always noted that caution needs to be exercised in interpreting those estimates. As discussed above, betas are a measure of the strength of the relationship between returns to individual stocks and the returns to the share market as a whole.[34] Therefore, an implicit assumption when observing foreign betas is that the strength of this relationship between, for example, US gas distributors and the US share market is approximately the same as the relationship between the returns to Australian gas distributors and the Australian share market. A number of factors may affect the strength of the relationship between gas distribution returns and overall market returns, including the share of different industries in the overall market across countries, differences in taxation regimes, as well as differences in market-average levels of gearing, all of which vary across markets.

The Commission does consider international evidence relevant, but only as a secondary source of information given the uncertainty surrounding the accuracy of international comparisons. This position is further supported by a recommendation of the Allen Report to the Commission that:[35]

> First and foremost, it must be borne in mind the Brattle Group beta estimates remain estimates for foreign firms and are measured against a foreign market (albeit one that has been reconstructed to resemble Australia). Thus, while it may be appropriate for a regulator to use their results as a secondary source of information when deriving a proxy beta, primary regard should be had to estimates of betas for Australian firms measured against the Australian market.

Given the inherent weaknesses associated with the Brattle Report and Epic's use of it, the Commission has not considered the findings of the Brattle Report as a primary source of information in determining the appropriate proxy beta for the MAPS.

Relevance of distribution entities as comparators

Epic has argued that the Commission's evidence for an asset beta is dominated by gas distribution systems. While it is correct to say that the Commission's analysis has included evidence relevant to distribution businesses, this has only been in the absence of more data on pure gas transmission businesses. It should also be noted that while gas transmission businesses are preferred over distribution businesses in determining a beta for a gas transmission business, gas distribution businesses exhibit far greater similarity in terms of systematic risk than the majority of the comparators used in the Brattle Report.

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[33] The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.229.

[34] Cit footnote 317: Formerly, the covariance between the returns to the stock and the overall market, standardised by the variance of the returns to the overall market.

[35] The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.56.

Much of the revenue earned by the firms included in the Brattle Report was derived from unregulated activities that are arguably more risky, and exhibit little similarity to a gas transmission business. The Commission considers that a regulated gas distribution business does in fact exhibit many of the characteristics of a gas transmission business, and is therefore likely to have a similar systematic risk or correlation with broader market movements and therefore beta. Epic has continually argued that the Commission has ignored the fundamental differences between gas transmission and distribution. This is not the case. The Commission addressed this issue in the *Final Decision*, and it is replicated below:[36]

> Epic disputed the relevance of Professor Davis' report to the Commission's assessment of the MAPS access arrangement on the basis that it ignores the fundamental difference between a distribution and a transmission system. Epic argued that the major risk differences between the distribution and transmission systems in South Australia, are;
>
> - the exposure of the MAPS to electricity generation load;
> - the MAPS reliance on South Australia's few large industrial users, the majority of which are connected directly to the MAPS; and
> - the risk of bypass.[37]

In response, Professor Davis stated that;[38]

> None of those listed [above] appear however to be relevant to assessing the systematic risk of the underlying asset (as opposed to its total risk). Unless cogent arguments can be advanced that such factors affect the degree of covariation between returns on the project and returns on the market portfolio, they are not relevant to determination of the asset beta. It is appropriate that, where relevant, such factors find reflection in the projections of expected demand used in the modelling approach to derive tariffs, or in arrangements for dealing with the possibility of asset stranding.

As stated previously, the Commission considers that while gas transmission businesses are the best comparators for developing a proxy beta for gas transmission entities, gas distribution businesses exhibit significant similarities such that data relating to the beta of gas distribution businesses is relevant for the Commission's assessment for gas transmission. Such findings are supported by the Allen Report. It established the following activity hierarchy for obtaining information to develop a proxy beta for gas transmission:

- regulated gas transmission;
- regulated gas distribution;
- regulated energy transmission / distribution; and
- regulated transmission / distribution network activities for other essential services (namely water and sewerage services).[39]

36 *Final Decision* for the Moomba to Adelaide Pipeline System, 12 September 2001, p.47.
37 Epic Energy, Response to *Draft Decision* – Part A, 10 October 2000, p.10.
38 Professor Davis, *Report on Asset and Debt Beta for MAPS*, 20 August 2001, p.2.

Empirical evidence

The Commission's *Final Decision* relied on a combination of empirical evidence, analysis of systematic risk facing the MAPS and regulatory precedent with respect to arriving at the maximum acceptable value for the asset beta of 0.50 (equity beta of 1.16). While considered to be the top of the plausible range at the time of the *Final Decision*, recent empirical analysis of publicly listed Australian gas transmission and distribution businesses reveals that an asset beta of 0.50 is extremely generous. It is envisaged that within a few years, there will be sufficient reliable Australian empirical evidence available to place less or no reliance on regulatory precedent in assessing the value for beta in the CAPM equation. Current indications are that the beta awarded could be substantially below the Commission's *Final Decision* for the MAPS. Following recent empirical analysis, the following conclusions were presented in the Allen Report:[40]

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North American or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.
>
> … while it inevitably is a matter for the Commission to decide how it exercises its discretion, it is recommended that, in the near term, it adopt a conservative approach, and not assume a proxy equity beta that is too far from the range of previous, relevant regulatory decisions. As noted above, these decisions typically have assumed a proxy beta (for the regulatory standard gearing assumption) of around 1. That said, this report has demonstrated that no implication can be drawn from current market evidence that the proxy betas that Australian regulators have adopted are likely to understate the 'true' beta – rather, as noted above, the current evidence suggests regulators systematically have erred in the favour of the regulated entities.

The analysis presented in the Allen Report is consistent with the findings of the ESC in its recent *Draft Decision* for the Victorian gas distributors. The ESC awarded an equity beta of 1, but indicated that this was on the generous side relative to current observations, which reveal an equity beta of less than 0.70 for Australian companies, and even lower for UK and US companies.[41] In awarding an equity beta of 1, the ESC made the following statement:[42]

> The Commission has adopted a proxy equity beta of 1 for the Victorian gas distributors' regulated activities, for an assumed gearing level of 60 per cent. This is approximately equivalent to an asset beta of 0.40 for a debt beta of zero, or 0.51 for a debt beta of 0.18. However, the Commission emphasises that this estimate is well above that which would be derived exclusively with reference to the latest market data. That is, in deriving this proxy beta, the Commission has placed *considerable weight* on

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39 The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.18.

40 The Allen Consulting Group, *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, July 2002, p.42-43.

41 The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.243.

42 The Essential Services Commission, *Review of Gas Access Arrangements Draft Decision*, July 2002, p.244.

> the desirability of continuity between regulatory decisions, and the long-term consequences of the Commission's decisions for the Victorian gas industry.
>
> However, the Commission notes that additional evidence from the capital markets will be available at future reviews of both the Victorian gas and electricity distributors. Barring mergers or other such activities, equity beta estimates for six comparable entities – AGL, Envestra, United Energy, Australian Pipeline Trust, AlintaGas and GasNet – using a full four years of observations will be available for all of these companies by the time of the 2008 gas access arrangement review. At that time, the Commission would envisage placing far more weight on the latest empirical estimates than it has at the current review.

The Commission's *Final Decision* for the MAPS determined a proxy equity beta of no more than 1.16. As stated above, the Allen Report indicates that a proxy equity beta of around 1 errs in favour of the regulated entity. The Commission does not consider it appropriate to lower its assessment of the maximum proxy beta for the MAPS at this stage of the assessment process. However, it should be noted that if the Commission were to divert from the maximum proxy beta allowed in its *Final Decision* for the MAPS, it would be downwards in light of current market evidence, and not in the direction sought by Epic.

Precision of international comparisons

In response to Epic's critique of the findings of the studies by Professor Kevin Davis and NERA[43] that were cited in the *Final Decision,* the Commission has restated the findings of the reports, in context, below. Epic stated that there was no evidence of adjustments that are required to make international beta comparisons. However, both studies contained discussion of the key adjustments necessary, and it was in this context that the conclusions of the reports were drawn.

Professor Kevin Davis' study of beta using a sample of US companies revealed that the average equity beta was 0.58 or below depending on the source and method of calculation. However in terms of the asset beta, when a company is levered the asset beta would be lower. With a 60:40 gearing ratio, as is fairly standard for gas transmission companies, an equity beta of 0.58 translates to an asset beta of less than 0.27.[44] This is the context in which Professor Kevin Davis stated that an asset beta of 0.50 would not be unreasonable.

As reported on page 50 of the Commission's *Final Decision*, the international comparison of regulated returns found that an asset beta of 0.5 was at the top of the range. Given 0.5 was considered to be at the top of the range, Epic's argument that the evidence advanced by the Commission does not suggest 0.50 is better than 0.55 or 0.60 is incorrect.

Epic's comment that the studies by Professor Kevin Davis and NERA are not precise is true to a certain extent. However, it should also be recognised that due to the Commission's concerns with the Brattle Report discussed above, it considers the findings of the Brattle Report to be no more precise. As stated in section 2.7.3 of

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[43] NERA: International Comparison o Utilities' Regulated Post Tax Rates of Return in: North America, the UK, and Australia, March 2001.

[44] This calculation assumes a debt beta of 0.06.

confidential annexure 2 to the *Final Decision*, the Commission considers an asset beta of 0.50 to be relatively high for the MAPS. That is, the Commission has adopted a value for the asset beta at the top of the plausible range, and considers 0.58 to be unreasonably high.

Comparison to Victorian Final Decision of 1998

With respect to Epic's comparison with the Commission's 1998 *Final Decision* for the Victorian gas transmission system, as noted in the *Final Decision* for the MAPS, the Commission has required an asset beta of 0.50 rather than 0.55, which it determined for the Victorian system in 1998. In 1998, the Commission added a premium to the asset beta for risk associated with the newness of the regulatory regime.[45]

Page 46 of the Commission's *Final Decision* for the MAPS states that the treatment of risk (Victorian 1998 decisions) associated with the newness of the regulatory regime is no longer considered appropriate, regardless of whether this perceived risk has increased or decreased. This is supported by Professor Kevin Davis' comments that follow in the Commission's *Final Decision* that:[46]

> If there does exist "regulatory risk" there is no obvious reason to believe that such risk would have a systematic element to it, which would warrant adjusting the underlying asset beta.[47]

It should also be noted that the Commission has not included a premium for the newness of the regulatory regime in any subsequent decision to the 1998 *Final Decision*.

Regulatory precedent

Epic argued that the Commission placed too much emphasis on regulatory precedent, and that the regulatory precedent actually supports a higher asset beta than 0.50. In reading the Commission's *Final Decision* however, it is evident that the Commission based its assessment of beta on analysis of the systematic risk relevant to the MAPS, empirical evidence and regulatory precedent. The Commission has assessed the asset beta with regard to regulatory precedent due to the level of reliable data available for Australian gas transmission businesses.

Conclusion

As previously stated, in arriving at its *Final Decision* with respect to beta, the Commission conducted a thorough assessment in accordance with the requirements of the Code. Among other factors specified in the Code, this included balancing the interests of users and the service provider. As Epic adopted an unreasonably high value for the asset and equity betas that did not comply with the *Final Decision*, the Commission has been forced to revisit its analysis and assessment.

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45 It should also be noted that information from Australian capital markets was scarce at the time of the Commission's *Final Decision* for the Victorian gas transmission system.

46 *Final Decision* for the Moomba to Adelaide Pipeline System, 12 September 2001, p.46.

47 Professor Davis, *Report on Asset and Debt Beta for MAPS*, 20 August 2001, p.2.

The Commission has become aware of further evidence supporting lower asset and equity betas than in set out in the *Final Decision*. In addition, the Commission has not viewed any evidence that would suggest the betas determined in the *Final Decision* were too low. In fact, if the Commission considered it appropriate to depart from the betas determined in the *Final Decision* at this stage in the process, it would revise the betas downwards, not in the direction sought by Epic.

2.3.4 Tariff setting

Amendment FDA2.4

For the access arrangement to be approved, the Commission requires Epic to amend the reference tariff proposed in Schedule 4 of the access arrangement. The amendment must have the effect that the FT tariff:

- is initially derived by applying the system primary capacity (as amended in amendment FDA3.2) to the revenue figure set out in Table 2.18 in the 'COS revenue ACCC *Final Decision'* column. Subsequent tariffs must be calculated by applying the approved escalator of 95 per cent of CPI;
- comprises a capacity charge and a commodity charge set to the same proportion used in Epic's Access Arrangement Information of 11 September 2000.

Implementation of amendment in revised access arrangement

Epic set out the approach it took to calculating tariffs from revenue in section 2.4.2 of it FDS5. The resulting tariffs are presented in Schedule 4 of Epic's revised access arrangement.

While the methodology adopted by Epic was consistent with amendment FDA2.4, the input figures to the equation were not as specified by the Commission. Epic used its own definition of system primary capacity (323 TJ/day) rather than the system primary capacity set out in amendment FDA3.2 (348 TJ/day). Epic also used its own determination of revenue rather than that calculated by the Commission.

Commission's assessment of revision for compliance with required amendment

The Commission considers that the methodology adopted by Epic to calculate tariffs from revenue is consistent with that set out in amendment FDA2.4. However, the Commission has recalculated tariffs using its input figures for the system primary capacity and for the revenue requirement.

Adopting the methodology set out by Epic in section 2.4.2 of Epic's FDS5, the Commission has calculated the tariffs set out in Table 1. The tariffs are also contained in schedule B of the access arrangement. The tariffs set out by Epic in schedule 4 of its proposed access arrangement of 22 January 2002 are to be replaced with those in Table 1.

Table 1: Tariffs

Tariff	Dollars per GJ
Commodity Charge:	**0.0704**
Mainline Capacity Charge Rate	**0.3348**
Whyalla Lateral Surcharge:	**0.2118**
IT Commodity Charge Rate	**0.4660**

As set out in amendment FDA2.4, these tariffs are to be escalated by 95 percent of CPI in accordance with Epic's proposal. The Commission's *Final Decision* included discussion of this escalation method in section 2.9.1. As discussed in the *Final Decision*, Epic's revenue has been smoothed/adjusted in addition to escalation at 95 percent of CPI so that the net present value of the revenue stream (over five years to the end of 2005) is consistent with the unsmoothed cost of service revenue.

In other words, as 95 percent of CPI is a steeper escalation profile than the unsmoothed revenue profile, Epic's revenue was adjusted downwards in the first year in order maintain the net present value of the cost of service revenue stream over the initial access arrangement period.

Therefore, even if the Commission were to approve the same tariff escalation profile for the second access arrangement period, users should not expect the tariff path to be continuous from 2005 to 2006. That is, a significant downwards reduction would need to be applied to Epic's revenue in order to maintain equivalent net present value with the unsmoothed cost of service revenue calculation going forward from 2005, all else remaining constant.

Amendment FDA2.5

For the access arrangement to be approved, the Commission requires Epic to set the IT tariff to the FT tariff multiplied by 1.15. The resultant IT tariff will not include any capacity charge.

Implementation of amendment in revised access arrangement

Epic has implemented the procedure set out in amendment FDA2.5 as demonstrated in Schedule 4. However, Epic has used its own FT tariff in the equation rather than that set out by the Commission. This is a result of non-compliance with other amendments.

Commission's assessment of revision for compliance with required amendment

The Commission has recalculated the IT tariff using the methodology set out in amendment FDA2.5, using the FT tariff calculated by the Commission after making all required amendments as discussed elsewhere in this Final Approval. The relevant IT tariffs are provided in Table 1 in the discussion of amendment FDA2.4 and schedule B of the access arrangement.

2.3.5 Services Policy

Amendment FDA3.1

For the access arrangement to be approved, the Commission requires Epic to insert the following wording into clause 24:

> Where an FT Service is curtailed, interrupted or discontinued pursuant to clause 24.1 the Service Provider will forfeit the proportion of any Capacity Charge for that Day equal to the amount of haulage service curtailed, interrupted or discontinued.

Implementation of amendment in revised access arrangement

FDA3.1 has not been incorporated into the revised access arrangement. However, clause 24.6 of the revised access arrangement has been modified as follows:

> The Service Provider will only be liable for any losses, costs, damages or expenses (and in respect of clause 24.5(a) this includes, but is not limited to, the proportion of any Capacity Charge for that Day equal to that proportion of the Service of a User whose Service is interrupted or curtailed under clause 24.1 other than to the extent that it is a reduction in Capacity caused by a User under clause 12) that the User may suffer or incur as a result of:

In Epic's FDS5, the company restated its position that the pipeline owner should have a degree of flexibility in its operation of the pipeline and that there are sufficient caveats under clause 24.1 to ensure that the service provider does not curtail users vexatiously or capriciously.[48]

Epic made further submissions in relation to the services policy in its Code Compliance submission (FDS4) lodged on 2 July 2002. Epic reiterated its view that it is not appropriate to increase the capacity of the pipeline above what it proposed in its access arrangement.[49] Epic contends that the greater the certainty with which FT service is provided, the lower the capacity that will be available for FT service. Epic also argues that requiring a greater degree of reliability for FT service will act to protect existing users and reduce the capacity available to prospective users.[50]

Commission's assessment of revision for compliance with required amendment

As noted in the *Final Decision*, users submitted that the indicative capacity of the pipeline is significantly higher than the capacity nominated by Epic in its services

48 Epic Energy FDS5, 22 January 2002, section 2.11.3.
49 Epic Energy FDS4, 2 July 2002, p.15.
50 Epic Energy FDS4, 2 July 2002 p.16.

policy.[51] Epic had submitted that the FT service in the access arrangement is offered to a higher degree of probability than under the existing haulage arrangements.[52]

The Commission accepts that the higher the degree of certainty to which FT service is offered the lower the system capacity available. While Epic claims it is offering a much more reliable service, clause 24.1 gives Epic a broad discretion to curtail FT service. That discretion reduces the degree of probability to which FT service is offered. Amendment FDA3.1 was required to ensure that the degree of certainty to which FT service is offered is consistent with Epic's claims.

Given Epic's submissions that the pipeline operator requires a degree of flexibility in the operation of its pipeline, amendment FDA3.1 provides a financial disincentive for Epic not to curtail services, while allowing Epic to maintain its ability to curtail when necessary.

In relation to Epic's claims regarding existing users being protected from competition from prospective users, the Commission notes that there are currently several prospective users involved in a dispute resolution process regarding the allocation of existing capacity on the MAPS.

Accordingly, the Commission has incorporated FDA3.1 into the access arrangement at clause 24.1.

[51] ACCC *Final Decision* MAPS, 12 September 2001, p.95.
[52] Epic Energy, Response to *Draft Decision* - Part C, 11 October 2000, p.3.

Amendment FDA3.2

For the access arrangement to be approved, the Commission requires Epic to include the National Power (now Pelican Point Power) expansion in the access arrangement.

The Commission requires Epic to amend clause 2.1 to include the Pelican Point Power expansion.

The Commission also requires Epic to amend clause 2.2 such that the System Primary Capacity of the Pipeline System includes the capacity of the Pelican Point Power expansion, that is 348 TJ per day. The Commission also requires clause 2 to be amended to take into account the eighth compressor at Wasleys.

The Commission also requires Epic to amend Schedule 1 to the access arrangement to take account of the Pelican Point Power expansion in the capacity of the Pipeline System. The Commission also requires Schedule 1 to be amended to take into account the eighth compressor at Wasleys.

The Commission also requires Epic to amend the Access Arrangement Information to take account of the Pelican Point Power expansion in the capacity of the Pipeline System. The Commission also requires the Access Arrangement Information to be amended to take into account the eighth compressor at Wasleys.

Implementation of amendment in revised access arrangement

FDA3.2 has not been incorporated into Epic's revised access arrangement. Epic indicated that it does not agree that the Pelican Point Power expansion can be included as part of the covered pipeline.

Commission's assessment of revision for compliance with required amendment

Epic's submission's regarding this amendment are discussed in relation to FDA3.33. The Commission is not satisfied that the revised access arrangement incorporates FDA3.2. Accordingly, the Commission has made the following amendments to the access arrangement:

- the Pelican Point Power expansion has been incorporated into clause 10.10(b)(i); and
- the Commission has made the amendments to clauses 2.1 and 2.2 of the access arrangement specified above.

The schedules and access arrangement information lodged by Epic on 22 January 2002 have not been updated to include the Pelican Point Power expansion or the compressor at Wasleys. As a result, these schedules and access arrangement information are no longer accurate.

The Commission has not amended the access arrangement information or the schedules to include the Pelican Point Power expansion. As indicated in section 2.3.9 of this *Final Approval*, it is not necessary for the access arrangement information to be updated by the Commission. However, the Commission has amended the access arrangement to reflect the inclusion of the Pelican Point Power expansion.

Amendment FDA3.3

For the access arrangement to be approved, the Commission requires that clause 6.7(b)(i) of the access arrangement be amended to read:

> it would not be technically or commercially reasonable for it to do so;

in order for clause 6.7(b)(i) to reflect the wording of section 3.10 of the Code.

Implementation of amendment in revised access arrangement

Amendment FDA3.3 has not been incorporated into Epic's revised access arrangement.

Commission's assessment of revision for compliance with required amendment

As discussed in section 2.3.6 below, a number of amendments were required to the terms and conditions and services policy to address the imbalance between the interests of users and the service provider. The interests of users and the service provider are relevant factors that must be taken into account under section 2.24 of the Code.

The Commission considers that the amendments made to Epic's revised access arrangement have addressed its concerns regarding FDA3.3. However, the Commission may reassess this clause at the next access arrangement period if circumstances indicate that it would be appropriate to do so.

Amendment FDA3.4

For the access arrangement to be approved, the Commission requires that the access arrangement be amended such that Epic is required to post its reasonable and prudent estimate of the following information on the EBB each day subject to a similar provision to that in clause 18.5(c):

- daily forecast for following month of number of compressor units likely to be available on the MAPS; and
- daily forecast for following seven days of Net Available Capacity of the pipeline system.

Implementation of amendment in revised access arrangement

Clauses 18.10 and 18.11 of the revised access arrangement require Epic to post its reasonable and prudent estimates of daily forecasts of the number of compressor units likely to be available and of unutilised system primary capacity for the following month. Epic has added two additional sub-clauses in relation to both clauses 18.10 and 18.11 under which Epic does not warrant or represent that the estimates will be available in full and it excludes its liability for any loss, cost or expense suffered or incurred by the User as a result of reliance on the estimate.

Commission's assessment of revision for compliance with required amendment

The Commission considers that the warranty and liability sub-clauses are not unreasonable. The Commission is satisfied that Epic's revised access arrangement incorporates FDA3.4.

2.3.6 Terms and conditions of service

Epic's submissions

Epic submits that the Commission must have regard to standard industry and commercial practice when assessing the terms and conditions of an access arrangement. Epic argues that the terms and conditions in its access arrangement are based on existing haulage agreements which is evidence that the terms and conditions are reasonable.[53]

Epic also submits that the Commission's assessment of the terms and conditions for the MAPS access arrangement is a reflection of micro-management that was not intended by the Code. Epic contends that the terms and conditions must be assessed in light of the factors set out in section 2.24 of the Code, and if they are acceptable in light of those factors, the Commission must recommend that they are acceptable.[54]

Commission's considerations

The Commission agrees that standard industry and commercial practice is a relevant consideration in determining whether the terms and conditions are reasonable. While assessing the terms and conditions, the Commission compared the access arrangement terms and conditions to Epic's existing haulage agreements and found significant discrepancies in some instances.

The Commission also agrees that the factors in section 2.24 are relevant to determining whether the terms and conditions are reasonable and has taken those factors into account.

When assessed as a package, the terms and conditions proposed by Epic in its access arrangement of 29 June 2001 did not adequately balance the interests of users and prospective users. As indicated in the *Final Decision*, the amendments made to the terms and conditions of the access arrangement were intended to redress the balance between the interests of users and the service provider.[55] A number of amendments were required to the terms and conditions in light of the submissions received and the onerous obligations placed on users by those terms and conditions.

An assessment of whether specific amendments required by the *Final Decision* have been substantially incorporated into the revised access arrangement is provided below.

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53 Epic Energy FDS4, 2 July 2002, p.17-18.

54 Epic Energy FDS4, 2 July 2002, p.18.

55 ACCC *Final Decision* MAPS, 12 September 2001, p. viii and 114.

Amendment FDA3.8

For the access arrangement to be approved, the Commission requires that clause 15.2 be amended to include the following provisions:

> If at any time during the Term uniform gas specifications for transmission pipelines are required by law, the Service Provider will adopt the uniform gas specifications, and they will apply in lieu of the Gas Specification.
>
> If at any time during the Term voluntary uniform gas specifications for transmission pipelines are introduced into the Australian Gas industry, the Service Provider may adopt the uniform gas specifications, in which case they will apply in lieu of the Gas Specification.

Implementation of amendment in revised access arrangement

Clauses 15.2(a) and (b) of Epic's revised access arrangement adopt FDA3.8.

Commission's assessment of revision for compliance with required amendment

The Commission is satisfied that the amendments made to the revised access arrangement substantially incorporate FDA3.8.

Amendment FDA3.9

For the access arrangement to be approved, the Commission requires that Epic amend clause 15.3(d) by adding the following provision:

> Provided that the service provider will not be indemnified to the extent that such losses, costs, damages and expenses result from its own negligence or default in complying with its obligations under the Agreement.

Implementation of amendment in revised access arrangement

Clause 15.3(d) has been modified as follows:

> Provided that the Service Provider will not be indemnified to the extent that such losses, costs, damages and expenses and penalties result from its own negligence or default in complying with its obligations under the Agreement (other than its obligations under clause 15.2(b)(v).

Commission's assessment of revision for compliance with required amendment

The Commission is satisfied that clause 15.3(d) substantially incorporates FDA3.9.

Amendment FDA3.10

For the access arrangement to be approved, the Commission requires Epic to insert the following provision into clause 15.3(b)(i) of the access arrangement:

> and will, as soon as it becomes aware that a User has introduced Non-Specification Gas into the Pipeline System, post a notice on the EBB notifying all Users of that fact.

Implementation of amendment in revised access arrangement

Clause 15.3(b)(v) has been modified as follows:

> (v) will as soon as it becomes aware that a User has introduced Non-Specification Gas into the Pipeline System, post a notice on the EBB notifying all Users of that fact (but failure to do so will not give rise to any liability on the Service Provider).

Epic submitted that it added the additional words 'but failure to do so will not give rise to any liability on the service provider' as the users will already have received notification of the non-specification gas through the receipt of an operational flow order ('OFO'). [56]

Commission's assessment of revision for compliance with required amendment

The Commission notes that there does not appear to be an obligation in clause 25 which requires the service provider to notify all users that non-specification gas has entered the pipeline.

Where non-specification gas has entered a pipeline the service provider has information which may be unavailable to users. This information could allow users to mitigate loss. However, a service provider should not bear liability for the loss suffered by users as a result of the actions of another user. In these circumstances it is reasonable that a service provider limits its liability. Accordingly, the Commission is satisfied with clause 15.3(b)(v) but notes that the clause will be subject to review during the second access arrangement period if necessary.

The Commission is satisfied that clause 15.3(b)(v) substantially incorporates FDA3.10.

Amendment FDA3.11

For the access arrangement to be approved, the Commission requires Epic to insert the following provision into clause 15 of the access arrangement:

> Where the Service Provider receives gas complying with the Gas Specification at the Receipt Point from all Users on a day but then supplies Non-Specification Gas at one or more Delivery Points, the Service Provider will indemnify the User from and against all losses, costs, damages or expenses that the Service Provider may suffer or incur as a result of the Non-Specification Gas entering the Pipeline System.

[56] Epic Energy FDS5, 22 January 2002, section 3.8.

Implementation of amendment in revised access arrangement

Clause 15.5 of the revised access arrangement has been amended to incorporate FDA3.11 subject to the following:

- use of the term ‘direct losses’ in place of ‘all losses, costs, damages or expenses’; and
- the inclusion of a qualification that the service provider will not indemnify for loss suffered as a result of the negligence or default of users.

Epic has submitted that:[57]

- it has limited the indemnity to ‘Direct Losses’ as the inclusion of all losses is not reflective of industry practice;
- it is unreasonable to impose mirror obligations on a service provider to that being imposed on the user because a service provider would only inject non-specification gas into the pipeline to ensure that it is able to provide services to users (for example, for the purpose of conducting maintenance); and
- asking a service provider to underwrite all risks associated with the delivery of non-specification gas, other than non-specification gas delivered by a user, is unreasonable and a service provider should not have to bear such risks.

Commission’s assessment of revision for compliance with required amendment

The Commission notes that the amendments made to clause 15.5 are consistent with the access arrangement. Clause 35.1 currently limits the liability of one party to another to direct losses only, therefore the use of the term ‘direct losses’ does not change the affect of the clause. The negligence and default portion of the clause is consistent with all other liability clauses in the access arrangement which provide that loss will not be indemnified where it was the result of the negligence or default of the party who suffered the loss.

The Commission is satisfied that clause 15.5 substantially incorporates FDA3.11.

Amendment FDA3.14

For the access arrangement to be approved, the Commission requires Epic to amend clause 18 of the access arrangement by removing clause 18.4(e) and replacing it with a new provision detailing the procedures to be followed when written confirmation is not received. These procedures must include:

- provision for FT Users to confirm by telephone, facsimile, e-mail or in writing at a time later than 1730 hours;
- provision for Epic to accept such requests if it is reasonable and prudent to do so;

[57] Epic Energy FDS5, 22 January 2002, section 2.6.

- provision that FT Service for which confirmation is given after 1730 hours be given a priority below FT Service, IT Service and Non-specified Services on the day; and
- provision for such Service to be provided on an interruptible basis.

Implementation of amendment in revised access arrangement

Clause 18.4(e) has been amended as follows:

> If, subject to clauses 18.4(c) and (d), the Initial Nominated Receipt Quantity is not confirmed pursuant to clause 18.4(a), then:
>
> (i) the User may still provide the Service Provider with the confirmation required by clause 18.4(a) by telephone, facsimile, e-mail or in writing and in doing so, the User will be deemed to have warranted and represented the contents of the communication;
>
> (ii) if clause 18.4(e)(i) applies, the service Provider may accept the confirmation but only if it is reasonable and prudent to do so;
>
> (iii) if the Service Provider accepts the confirmation pursuant to clause 18.4(e)(ii), then the following provisions apply:
>
> (A) The User's FT Service for the Day will rank in priority behind all other Services for that Day only.
>
> (B) The Service Provider will use its reasonable endeavours to deliver the quantity confirmed under clause 18.4(e)(ii).
>
> (C) The User's FT Service for the Day shall be deemed to be interruptible at the Service Provider's discretion as a reasonable and prudent pipeline operator.

Commission's assessment of revision for compliance with required amendment

The Commission considers that the amendments made to clause 18.4(e) substantially address the previously onerous consequences arising from the failure of a FT user to provide written confirmation of the supply of the initial nominated receipt quantity.

The Commission considers that clause 18.4(e) of the revised access arrangement substantially incorporates FDA3.14.

Amendment FDA3.16

For the access arrangement to be approved, the Commission requires Epic to amend the access arrangement to provide that if the service provider does not notify the User of an Imbalance by 0900 hours on any day, then the service provider may not levy the Excess Imbalance Charge for that day.

Implementation of amendment in revised access arrangement

Clause 19.3(a)(ii) of the revised access arrangement has been amended as follows:

(i) if the Service Provider has notified the User of the Imbalance pursuant to clause 19.2(a) (or it has failed to do so and that failure is due in part or in total to the failure of the User to provide the Service Provider with the necessary information to enable it to comply with clause 19.2(a)), an Excess Imbalance Charge will be payable by the User on that amount of the excess Imbalance not exchanged in accordance with clause 20.1.

Commission's assessment of revision for compliance with required amendment

The Commission is satisfied that the amendment to clause 19.3(a)(ii) substantially incorporates FDA3.16.

Amendment FDA3.17

For the access arrangement to be approved, the Commission requires that Epic amend clause 19.4 by deleting the phrase 'and if it is of such a nature' and replacing it with 'and if the conditions in clause 25.1(a)(i) are met'.

Implementation of amendment in revised access arrangement

The words 'and if it is of such a nature, issue an OFO' have been replaced with 'exercise its rights under clause 25' in clause 19.4.

Commission's assessment of revision for compliance with required amendment

The clause ensures that Epic's ability to issue an operational flow order is restricted to clause 25. Accordingly, the Commission is satisfied that the amendment made to clause 19.4 of the revised access arrangement substantially incorporates FDA3.17.

Amendment FDA3.22

For the access arrangement to be approved, the Commission requires Epic to insert a provision to provide for an alternative allocation procedure where parties taking delivery of gas at a delivery point agree to the allocation procedure. The parties will provide the service provider with a copy of the agreement. If an agreement is not reached, Epic is to allocate deliveries to the parties at the delivery point pro rata, based on their respective nominations at the delivery point.

Implementation of amendment in revised access arrangement

Clause 22 of the revised access arrangement has been amended so those users sharing a delivery point can agree to the proportional share of the gas stream at the delivery point. If a user fails to provide a copy of this allocation agreement to the service provider, the service provider can apportion the gas to users on the basis of the following:

- users' contractual rights at the delivery point;
- users' nominations at the delivery point; or

- any other information to which a reasonable and prudent pipeline operator would have regard.

Commission's assessment of revision for compliance with required amendment

The Commission considers that clauses 22.2(b)(iii), (iv) and (v) provide a satisfactory mechanism by which a service provider can allocate capacity. The Commission is satisfied that the revised access arrangement substantially incorporates FDA3.22.

Amendment FDA3.24

For the access arrangement to be approved, the Commission requires Epic to replace the words 'the User' in clause 23.2(a) with the words 'all Users'.

Implementation of amendment in revised access arrangement

The words 'a user whose priority will be adversely affected' have been inserted into clause 23.2(a).

Epic has submitted that its modifications to the clause is a suitable compromise and addresses the Commission's concerns.[58]

Commission's assessment of revision for compliance with required amendment

The Commission considers that the amendment to clause 23.2(a) is sufficient because the amendment made ensures that users who will be affected by the ranking of a non-specified service above IT services will be notified.

The Commission is satisfied that the revised access arrangement substantially incorporates FDA3.24.

Amendment FDA3.25

For the access arrangement to be approved, the Commission requires Epic to:

- Amend clause 24.3(a) by deleting after the word 'greater' the words 'or less'.
- Amend clause 24.6 as follows:

> The Service Provider will only be liable for any losses, costs, damages or expenses that the User may suffer or incur as a result of:
>
> (a) any curtailment, interruption or discontinuation invoked by the Service Provider under clause 24.1;
>
> (b) the User complying or failing to comply with a curtailment notice invoked by the Service Provider which was issued negligently or in breach of the Service Providers obligations under the Agreement;

[58] Epic Energy FDS5, 22 January 2002, section 2.9.

(c) any curtailment, interruption or discontinuation invoked by the Service Provider under clause 24.5 where the Service Provider has been negligent or has failed to comply with its obligations under the Agreement.

- Add to clause 24.2 the following clause:

  The Service Provider will, on reasonable request by a User, provide such information as is reasonably required to justify the issue of a curtailment notice.

Implementation of amendment in revised access arrangement

- The words 'or less' have been deleted from clause 24.3(a) of the revised access arrangement;
- clause 24.6 of the revised access arrangement does not incorporate the required amendments;
- clause 24.2 of the revised access arrangement has been amended as follows:

  The Service Provider will, on a reasonable request by a User and within a reasonable time after the request is made, provide such information as is reasonably required to support the issue of a curtailment notice. Nothing in this clause 24 limits a Service Provider's rights to curtail, interrupt, or discontinue in accordance with the provisions of this Agreement.

In relation to the changes made to clause 24.6 of the revised access arrangement, Epic has submitted that:[59]

- a reasonable and prudent pipeline operator needs to be able to promptly respond to fluctuating operating conditions of a pipeline on a day to day basis, conditions which are often out of the service provider's control;
- a service provider should not be penalised as a result of exercising its curtailment rights;
- it will not be able to recover any capacity charge and this is sufficient disincentive to prevent Epic from exercising its rights under clause 24.1 unnecessarily; and
- the amendment amounts to a double penalty for the service provider when combined with the inability to impose a capacity charge in relation to the amounts curtailed.

In a subsequent submission, Epic also submitted that changes to liability and indemnity clauses would increase the number of access disputes.[60]

Commission's assessment of revision for compliance with required amendment

The Commission is satisfied that clauses 24.3(a) and 24.2 of the revised access arrangement have been amended to incorporate FDA3.25.

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[59] Epic Energy FDS5, 22 January 2002, section 2.10.
[60] Epic Energy FDS4, 2 July 2002, p.18.

The Commission notes that clause 24.1 provides discretion to the service provider to curtail FT services where capacity is insufficient to meet scheduled quantities for any reason. The purpose of the required amendment was to address concerns raised by users that the clause provided the service provider with too much discretion, while allowing the service provider to retain the right to curtail and the necessary flexibility to do so.

As noted above, the Commission's overriding concern in relation to the terms and conditions of the access arrangement was that when considered as a package, they placed onerous obligations on users and represented an unfair balance between the interests of users and the service provider. Given that the majority of amendments required to the terms and conditions have been incorporated into the revised access arrangement, the balance between the interests of users and service provider has been addressed. As such, the Commission is satisfied that its concerns have been addressed.

The Commission is satisfied that clauses 24.2 and 24.3(a) substantially incorporate FDA3.25 and that its concern regarding clause 24.6 is otherwise addressed.

Amendment FDA3.29

For the access arrangement to be approved, the Commission requires that Epic:

- Amend clause 36.4 as follows:

  > The User may terminate the agreement and/or suspend its obligations under the agreement if the Service Provider…

- Add, after clause 36(b) the following clause:

  > (c) fails to pay any amount due to the User and that amount, plus interest accrued at the Interest Rate plus 2 per cent per annum, is still outstanding 7 Days after the date of a notice of demand from the Service Provider.

Implementation of amendment in revised access arrangement

Clause 36.4 of the revised access arrangement has been modified as follows:

> The User may terminate the Agreement or suspend the Operation of this Agreement until the default or failure referred to in (a), (b) or (c) below has been rectified, if the Service Provider
>
> (c) fails to pay any amount due and payable to the User under this Agreement and that amount, plus interest accrued at the Interest Rate plus 2 percent per annum, is still outstanding 7 Days after the date of a notice of demand from the User.

Commission's assessment of revision for compliance with required amendment

The Commission is satisfied that the clause 36.4 substantially incorporates FDA3.29.

2.3.7 Extensions and Expansions policy

Amendment FDA3.33

For the access arrangement to be approved, the Commission requires that Epic amend clause 10.4(b) to the following:

> At the time it comes into operation, any New Facility, except for an extension to the Pipeline, is to be considered part of the Covered Pipeline, unless at that time the Regulator agrees that the New Facility should not be covered. Extensions will be part of the Covered Pipeline, unless the Service Provider, by notice to the Regulator (given before those facilities come into service) elects otherwise.

Implementation of amendment in revised access arrangement

The expansions policy, clause 10.10 of the revised access arrangement, has not been amended.

As noted in the *Final Decision*, Epic has previously indicated that in its view, its proposed expansions policy is consistent with the Code.[61] Epic has reiterated and expanded on its view in a recent submission. Epic submits that:[62]

- the Commission has afforded paramount significance to the factors listed in section 2.24 of the Code and has applied them without due regard to sections 3.16 and 3.17 of the Code;
- Epic's proposed expansions and extensions policy is consistent with the Code;
- the Commission's primary rationale for requiring FDA3.33 is to ensure that the Pelican Point Power expansion forms part of the covered pipeline;
- amendment FDA3.33 is inconsistent with the Code, unlawful and beyond the scope of the Commission's discretion; and
- the access arrangement cannot apply to an expansions constructed prior to the access arrangement coming into effect because the access arrangement cannot have a retrospective effect.

In relation to its ability to exercise market power in the terms and conditions of an expansion of the pipeline, Epic contends that:[63]

- its commercial interests are to maximise the capacity of the pipeline and therefore it is not in its interests to exercise market power;
- given the current proposals for alternative fuel sources into Victoria Epic is not in position to exercise market power. However, Epic also submitted that it is highly unlikely that prospective users will have access to firm capacity in this or the next

[61] ACCC *Final Decision* MAPS, 12 September 2001, p.171.
[62] Epic Energy FDS4, 2 July 2002, p.25-28.
[63] Epic Energy FDS4, 2 July 2002, p.27-28.

access period unless the pipeline is expanded and that the next expansion of the MAPS is imminent; and[64]

- the threat of coverage by the NCC would constrain the exercise of market power.

Commission's assessment of revision for compliance with required amendment

The Commission's reasoning for this amendment is set out fully in the *Final Decision*, however, a brief overview is provided below.

The Commission's primarily reason for requiring FDA3.33 was not, as Epic contends, to ensure that Pelican Point Power expansion could form part of the covered pipeline. The amendment was based on the Commission's concern that Epic may be able to exercise market power in relation to the terms and condition, including price, of an expansion.[65] If an expansion were covered, potential users would have access to the dispute resolution processes in the Code, which would constrain Epic's ability to exercise market power. Similarly, coverage of the Pelican Point Power expansion is required because Epic would be a in a position to exercise market power in respect of that capacity in the future.

A similar expansions policy was required in the Commission's *Draft Decision* in relation to the Amadeus Basin to Darwin Pipeline due to the possibility that the service provider could exercise market power in relation to an expansion.

Section 3.16 of the Code requires that an expansions/extensions policy provide a method for determining whether an expansion will be covered. However, in addition to section 3.16, section 2.24 of the Code must be considered. Section 2.24 sets out a number of factors that the Commission must take into account when assessing a proposed access arrangement, including the public interest, the economically efficient operation of the covered pipeline and the interests of users and prospective users.

As discussed in the *Final Decision*, the exertion of market power in relation to tariffs for expanded capacity would affect the public interest, particularly in having competition in related markets, the economically efficient operation of the pipeline and the interests of users and prospective users.

The Commission concluded that given the environment in which an expansion is most likely to occur, the factors in section 2.24 required that an expansion be covered. Accordingly, the expansions policy set out in Epic's revised access arrangement of 22 January 2002 is not consistent with the requirements of the Code.

External legal advice sought by the Commission confirms that the Commission may require an expansions policy that is formulated in consideration of the factors in section 2.24 of the Code. As such, the Commission is able to require the amendment to Epic's expansions policy specified in amendment FDA3.33.

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[64] Epic Energy FDS4, 2 July 2002, p.16 and 20.

[65] ACCC *Final Decision* MAPS, 12 September 2001, p.171-172.

Pelican Point Power

Epic has argued that the Pelican Point Power expansion cannot be covered by the access arrangement because an access arrangement cannot have a retrospective effect. However, as indicated in the *Final Decision*, the Commission is not applying section 1.40 of the Code retrospectively. The Pelican Point Power expansion will become part of the covered pipeline at the time that the access arrangement comes into effect in accordance with the expansions policy.

Legal advice has confirmed that the Commission's contention, that an expansion constructed after the pipeline becomes a covered pipeline, but before an access arrangement takes effect, can be dealt with pursuant to the extensions/expansions policy in the access arrangement.

FDA3.2 of the *Final Decision* required Epic to include the Pelican Point Power expansion in the access arrangement. As Epic has not done so, the Commission has specifically incorporated it into clause 10.10(b)(ii).

Market Power of the Service Provider

In its *Final Decision*, the Commission concluded that Epic would have market power in relation to the terms and conditions of an expansion. The basis of that finding was that at the time that the *Final Decision* was issued, there was excess demand for the MAPS as evidenced by an access dispute regarding allocation of capacity on MAPS which was, and continues to remain, on foot.[66]

The Commission's findings are consistent with the rationale for coverage of infrastructure such as the MAPS, which was that due to the service providers market power, regulation was necessary to facilitate competition in upstream and downstream markets.[67] Further, one of the objectives of the Code is to prevent the abuse of market power, the clear implication of which is that the owners of assets regulated by the Code have market power.[68]

Comments made by Epic in relation to its Dampier to Bunbury Pipeline (DBP) illustrate that in practice, the views expressed above are well founded. In fact, Epic has indicated that if the reference tariffs for the DBP were less than $1/Gj and $1.08/Gj, 'it would be forced to charge much higher amounts, up to $2Gj, for any new customers'.[69] Epic is clearly of the view that it could charge a substantially higher price for an expansion. While these comments relate to another pipeline that is operating in a different market, the Commission's view is that Epic would have similar discretion in relation to the MAPS.

In these circumstances the Commission does not agree that the threat of coverage is an effective constraint on Epic's ability to exercise market power. Absent the expansion policy required by the Commission or the election of the service provider, the only mechanism by which an expansion would be covered is if the relevant Minister decides

66 ACCC *Final Decision* MAPS, 12 September 2001, p.171 and 177.
67 Competition Policy Reform Bill, Second Reading Speech, 30 June 1995 Hansard at 2799.
68 Code, Introduction, p. 1.
69 Weir M, The West Australian, Court to Rule on Epic's Gas Battle', 20/5/02.

it should be in accordance with sections 1.2 to 1.19 of the Code. However, an application for coverage cannot be lodged with the NCC until after the pipeline has been constructed.[70] Most expansions would be constructed after a foundation contract has been entered into. Accordingly, the threat of coverage would not constrain Epic in regard to the terms and conditions of a foundation contract for an expansion.

In contrast, if there was a presumption of coverage for an expansion, a prospective user could notify a dispute under the Code if Epic sought to exercise market power.

Developments since the Final Decision

Two pipelines from Victoria to South Australia have been proposed by two different consortia. Since the *Final Decision* was released, one of those proposals, SEA gas, now appears more likely to proceed. On 29 May 2002 the proponents of the pipeline announced that construction of the SEA gas pipeline would commence in October and that the projects financing arrangements had been finalised.[71]

There is currently an access dispute ongoing in relation to the allocation of capacity on the MAPS. The dispute was triggered due to excess demand for the MAPS and remains on foot. In May 2002 Commission staff met with a number of users to gauge the level of demand for MAPS. At that time, users were not able to give an indication of their likely demand.

It is not possible for the Commission to determine definitively whether SEA gas will proceed, and what impact it would have on Epic's market power if it does. A second pipeline would not necessary constrain Epic's market power. Even if a second pipeline proceeds, the MAPS remains the only transmission pipeline from Moomba to Adelaide, and therefore the service provider may retain a high degree of market power where users have contracts to purchase gas from Moomba.

Additionally, it is noteworthy that the NCC has recently released a draft recommendation that the Moomba to Sydney Pipeline (MSP) remain covered on the basis of evidence of the service provider having sufficient market power to engage in monopoly pricing. The MSP faces competition from the Eastern Gas Pipeline and the interconnect between Culcairn and Barnawartha.

Given this uncertainty, the Commission considers that the best way forward is to modify the expansions policy so that the decision regarding whether or not an expansion should be covered can be made prior to the construction of the pipeline. Thus, if market conditions do alter after this decision is released, Epic would have an opportunity to make submissions to that effect prior to an expansion being constructed.

Conclusion

The Commission has amended clause 10.10(b) of the access arrangement so that it complies with FDA3.2 and FDA3.33, subject to a minor modification in relation to the time that a decision regarding whether or not an expansion should be covered is made.

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70 Code, section 1.22, 1.23 and section 10.8 (definition of Pipeline).

71 SEA gas, Media Release: *Funding Deal Secures Start of $300 Million SEA gas Pipeline*, 29 May 2002, http://www.seagas.com.au/attachments/FC_Media_Release.doc.

2.3.8 Queuing Policy

Amendment FDA3.34

For the access arrangement to be approved, the Commission requires Epic to replace clauses 10.1 – 10.3 of its 29 June 2001 access arrangements with clauses 10.1 to 10.7 of its proposal of 29 August 2001.

Implementation of amendment in revised access arrangement

Epic has changed the queuing policy in its revised access arrangement to incorporate most of clauses 10.1 to 10.7 of its proposal of 29 August 2001. However, Epic has made a number of modifications to several of those clauses and inserted additional sub-clauses that were not required in the *Final Decision*.

The clauses modified significantly by Epic include the following:

- Amendments to clause 10.3(c) and (d) with the effect that a complying request can only be withdrawn from the spare capacity queue if notice is given to the service provider before the open season closing date. Where a prospective user has not given such notice the prospective user will be bound to that portion of the complying request that can be satisfied.
- Clause 10.5, which applies to complying requests that do not exceed spare capacity, provides that each request entered into the spare capacity queue prior to the close of the open season will be an irrevocable complying request capable of immediate acceptance.
- The inclusion of clauses 10.8, which provides for a different queuing policy for IT access requests. Clauses 10.2 to 10.7 regulate the queuing policy for FT requests and utilise an open season process, whereas an open season process is not utilised for a non-FT request.

Epic has submitted that the 'general thrust' of the amendments required in the *Final Decision* has been retained but that a number of further modifications were made for the following reasons:[72]

- to prevent parties from making ambit claims and to impose an additional tension on parties seeking non reference services; and
- to ensure that the priority of prospective users' requests are retained.

Epic made additional submissions in relation to the queuing policy in FDS4. Those comments relate to whether the queuing and expansions policy is likely to encourage expansion of the pipeline. The provisions of the access arrangement the subject of Epic's submissions relate to clauses that Epic itself proposed. Accordingly, those submissions are not discussed in this *Final Approval*.

[72] Epic Energy FDS5, 22 January 2002, section 3.4.2.

Commission's assessment

The Commission has reviewed the modification to clauses 10.1 to 10.7 made by Epic. Most of these are inconsequential and do not need to be discussed. However, the changes listed above warrant further discussion.

Clause 10.3(c) and (d)

The affect of the amendments to clauses 10.3(c) and (d) is that a prospective user cannot withdraw a request for service after the open season closing date. Previously, clause 10.2(c) of the proposed amendment in the *Final Decision* allowed a user to give notice to the service provider without the open season time restriction applying.

Subject to changes in circumstances, if requests for capacity are bona fide then clauses 10.3(c) and (d) should not present an impediment to users. Given that users would be bound to the request after the open season closure date, this clause is likely to limit ambit requests.

There is currently an access dispute ongoing in relation to the allocation of capacity on the MAPS. This process has been ongoing since November 2000. Clauses 10.3(c) and (d) may assist in avoiding similar future arbitration or at least ensure that disputes relate only to bona fide claims.

The Commission recognises that difficulties may arise where users require the full amount of the capacity requested for project specific purposes but are only allocated a portion of their request. The effect of clause 10.3(d) is to bind users to that amount. Commission staff met with a number of users in May 2002 who confirmed that this could be problematic, particularly where the user and service provider are unable to agree on terms and conditions for developable capacity.

The Commission notes the concerns raised, but considers that there is some merit to the clauses given the costs associated with dispute resolution.

The Commission also notes that the pipeline is fully contracted until 1 January 2006, and the access arrangement period also expires at that time. Additionally, capacity requests for the period from 2006 onwards will be allocated in accordance with the access dispute notified under the *Natural Gas Pipelines Access Act (South Australia)* 1995.

While the Commission acknowledges that some modification to this clause may be necessary to balance the interests of users and the service provider, given the relevance of the queuing policy at this time, the most appropriate time to make those adjustments would be for the next access arrangement period. At that stage consultation could be conducted with both the service provider and users.

Clause 10.5

Clause 10.5 is the equivalent of clause 10.4 in the proposed queuing policy in the *Final Decision*. Clause 10.4 provided for a negotiation process for the purpose of reaching an agreement on a relevant applicable contract. Under clause 10.5 a request is irrevocable and where demand does not exceed supply, the service provider will complete the applicable contract and forward this to the user for execution, unless the parties decide otherwise.

Difficulties due to users not being allocated the full amount needed for project specific purposes will not arise under this clause because 10.5 relates to situations where demand does not exceed capacity.

The phrase “unless the parties otherwise agree” provides some scope for negotiation. However, the Commission is concerned that given the request is irrevocable, the ability of users to negotiate terms and conditions may be limited.

The Commission notes that clause 10.5(b) of the revised access arrangement is equivalent to clause 10.6(c), (f) and (i), which apply where the complying requests exceed spare capacity. Users were consulted on what is now clause 10.6 of the access arrangement prior to the release of the *Final Decision*. Users did not raise any concerns relating to complying requests becoming ‘irrevocable’.

Further, the terms and conditions of the access arrangement have been subject to extensive consultation with users and provide a fair balance between the interests of users and the service provider. The Commission notes that users are able to access the arbitration process set out in the Code if agreement cannot be reached with the service provider. Also, a user could specify that its request for service is conditional on specific terms and conditions that a user requires. In that case, where the service provider refused to include those terms and conditions, the user would not irrevocably bound to contract for the capacity.

Clause 10.8

The *Final Decision* did not include a distinction between the queuing policy for FT requests and non-FT requests.

The Commission considers that it is not necessary to conduct to an open season process for non-FT service. Non-FT contracts tend to operate for shorter periods of time and an open season process could be overly burdensome.

This clause allows the service provider to give priority to FT users over non-FT users, which assists the service provider to maximise utilisation of the pipeline and accordingly, maximise the gas into South Australia. This is in the interest of the public, the service provider and users.

Conclusion

The Commission is satisfied that the revised queuing policy substantially incorporates FDA3.34.

Amendment FDA3.35

Amendments to Epic’s proposal of 29 August 2001

Notification of other disputes

For the access arrangement to be approved, the Commission requires Epic to add the following into clause 10.5:

> If a Prospective User notifies a dispute in relation to the Spare Capacity which was the subject of an Open Season before the negotiation and conciliation processes have been completed, the Relevant Regulator may consider, in accordance with section 6.3 of the Code, whether an alternative dispute resolution process would be appropriate.

The Commission is satisfied that this amendment is incorporated into clause 10.6(h).

Epic not to agree to allocate spare capacity outside of the queuing policy

For the access arrangement to be approved, the Commission requires Epic to add the following at the start of clause 10.1:

> Before the Service Provider agrees to allocate Spare Capacity it must undertake the Open Season process described in clause 10.3.

This amendment has not been incorporated into the access arrangement. The Commission considers that clause 10 as a whole ensures that spare capacity allocation cannot be undertaken without the open season process and therefore the Commission's concerns have been otherwise addressed.

Qualification of clause 10.4(f)

The Commission notes that the amendment to clause 10.4(f) is not necessary as a result of the deletion of the previous clause 10.4(f). The Commission is satisfied that its concerns have been otherwise addressed.

Qualification of clause 10.5(c)

For the access arrangement to be approved, the Commission requires Epic to add the following to clause 10.5(c) after the words 'clause 8.1 will apply':

> at the close of the period referred to in 10.5(d).

This qualification has been added to clause 10.5(c) of the revised access arrangement.

The Commission is satisfied that clause 10.5(c) incorporates FDA3.35.

Clarification of clause 10.5(f)

For the access arrangement to be approved, the Commission requires Epic to add the following to clause 10.5(f) after the words 'Spare Capacity':

> pursuant to the alternative dispute resolution process

This clause has been amended to include the reference to the alternative dispute resolution process.

The Commission is satisfied that clause 10.5(f) complies with FDA3.35.

Clarification of clause 10.5(h)

For the access arrangement to be approved, the Commission requires Epic to add the following to clause 10.5(h) after the words ‘Spare Capacity’:

> pursuant to the arbitration process

Clause 10.5(h) is now clause 10.6(i) of the revised access arrangement. The words ‘pursuant to the arbitration process’ have not been included in clause 10.6(i).

The Commission considers that the words ‘upon a determination by the arbitrator of the access dispute’ at the beginning of clause 10.6(i) provides that spare capacity may only be allocated pursuant to the outcome of the dispute resolution process. The Commission is satisfied that its concerns have been otherwise addressed.

2.3.9 Access Arrangement Information

Amendment FDA4.1

For the access arrangement to be approved, the Commission requires Epic to revise the access arrangement information so that it is consistent with the latest revised access arrangement (version 29 June 2001) and the amendments specified in this *Final Decision*.

Implementation of amendment in revised access arrangement

The access arrangement information submitted on 22 January 2002 has not been updated and does not reflect the amendments required by the Commission in the *Final Decision*.

Commission’s assessment of revision for compliance with required amendment

The access arrangement information clearly does not comply with FDA4.1. This appears to be because Epic has not complied with the *Final Decision* amendments which required subsequent additions to the access arrangement information. In particular, the following amendments have not been complied with:

- FDA2.1 required the value of the initial capital base to be set to the value derived by the Commission, is $353.3 million as at 30 June 2001.
- FDA2.2 required the working capital component not to be included in the value of the capital base for the purpose of calculating Epic’s capital charge (return of capital assets).
- FDA2.3 required the WACC estimates and associated parameters set out by the Commission in Table 2.13 and Table 2.14 to be adopted and used to determine base target and forecast revenues.

- FDA3.2 requires, in part, that Epic incorporate the Pelican Point Power expansion into the capacity of the Pipeline System.

As discussed throughout the *Final Approval*, the Commission has made the amendments listed above to the access arrangement. Accordingly, the access arrangement information is not consistent with the access arrangement.

Section 2.6 of the Code sets out the purpose of the access arrangement information and provides that it must contain information that in the Regulator's opinion:

> ...would enable Users and Prospective Users to understand the derivation of the elements in the proposed Access Arrangement and to form an opinion as to the compliance of the Access Arrangement with the provisions of the Code.

The Commission has previously issued a *Draft Decision* and a *Final Decision*, which comprehensively detailed the service provider's proposals and the amendments required by the Commission and the rationale for those amendments. Similarly, the *Final Approval* is a comprehensive document. For additional certainty, two schedules, schedules A and B, have been added to the access arrangement which set out the numerical calculations used to determine tariffs and the tariffs. Additionally, references in the access arrangement to the access arrangement information have been amended where necessary.

In conclusion, it is clear from each of these documents how the elements in the access arrangement have been derived. Accordingly, the Commission does not consider it necessary to draft its own access arrangement information.

2.4 Additional amendments

Epic made a number of changes to its revised access arrangement which were not required in the *Final Decision*. Epic submitted that these amendments were a necessary consequence of the *Final Decision* amendments.[73] These amendments are as follows:

- changes to clause 8 regarding procedures for entering into a contract for service to reflect the revised queuing policy;
- a requirement in clauses 6 and 7 that a request for service be accompanied by an executed EBB system agreement together with the EBB user charge in order to ensure all participants of an open season are aware of the outcome;
- minor amendment to clauses 13.1 and 13.2 which make the obligations of the service provider to accept gas supplied by the user and deliver it to the user subject to the user supplying the gas to the service provider;
- minor amendments to clause 20.1 relating to the notice requirements for deadlines on a users' right to trade its imbalance;
- minor amendments to clause 21.2 relating to the deadline for notification of users' allocation arrangements with producers and other users;

[73] Epic Energy FDS5, 22 January 2002, section 3.

- the inclusion of clause 21.3 relating to which allocation process will be adopted by the service provider in circumstances where the service provider has issued an OFO or a curtailment notice; and
- minor amendment to clause 34.4 relating to the ability of the service provider to provide the relevant service during an event or circumstance of force majeure.

Commission's assessment of amendments

The Commission considers that the additional amendments that Epic has made are not material and these amendments comply with the requirements of the Code.

2.5 Insurance Issues

Epic made a confidential submission in relation to self-insurance on 26 March 2002 through Final Decision Submission #6, Insurance Issues (FDS6). The Commission replied to Epic's submission in a letter of 16 April 2002, requesting substantiation for Epic's claim, and a public version of the submission to enable appropriate public scrutiny. The Commission also noted that insurance costs should be included as operations and maintenance (non-capital costs). Epic already had an allowance for insurance expenditure.

On 2 July 2002 Epic provided Final Decision Submission #4, Code Compliance (FDS4) in which Epic argued against the approach set out in the Commission's letter of 16 April 2002. Epic indicated in FDS4 however that FDS6 could be made public. Consequently, the Commission published both documents on its web-site.

Epic's submissions and the Commission's assessment are set out in more detail below.

2.5.1 Epic's confidential proposal

Epic submitted that renewing its insurance policies had proven difficult and costly due to recent world events. In addition, Epic stated that for some risks insurance cover is either not available or only available at such a high price that it would be unreasonable and imprudent to obtain cover.[74]

As such Epic proposed to self-insure against some risks and retain insurance cover against other risks but did not specify which risks it would self-insure against and which it would externally insure against.

Epic proposed that it should be compensated for self-insurance by adding a premium to the return on equity. Specifically, Epic submitted that a premium of at least 0.6 percent would be necessary. This would result in an increase of approximately $850 000 in Epic's revenue requirement. Epic also proposed to retain the current allocation within its non-capital costs for insurance of approximately $250 000.

Epic proposed compensation via a premium on the return on equity rather than as non-capital costs because of the uncertainty and difficulty in quantifying the appropriate

[74] Epic Energy FDS6, 26 March 2002, p.2.

amount, and argued that it was normal commercial practice in such circumstances.[75] Epic also argued that such an approach was consistent with previous regulatory decisions such as for the Victorian access arrangements in 1998 and for the Central West Pipeline.[76]

2.5.2 Commission's response

The Commission considered the submission made by Epic concerning self-insurance before writing to Epic on 16 April 2002. In its reply to Epic's submission, the Commission noted that if an operator chooses to self-insure for non-systematic risk, it is appropriate to include the prudent premium in the calculation of the revenue requirement. However, the Commission noted that further quantification of Epic's proposal was required in addition to a public version of FDS6 to facilitate public scrutiny prior and assessment.

The Commission also indicated that if self-insurance costs were to be included in the access arrangement they should be included explicitly as non-capital costs rather than through a premium on the cost of capital. Such a premium would undermine the integrity of the Capital Asset Pricing Model (CAPM) and therefore the integrity and reliability of its output. Section 8.31 requires that returns be calculated on the basis of a well accepted financial model such as the CAPM. The Commission therefore considers that consistency with the Code requires a robust application of the financial model chosen, in this case the CAPM.

The Commission understands that a service provider contemplating self-insurance would ordinarily conduct a detailed risk analysis to satisfy debt provider and/or corporate governance requirements. Such analysis is likely to include an assessment of the particular risk/s involved, the probability of occurrence and the impact on the business and its cash flow should the event occur.[77]

The Commission informed Epic that to assess its proposal for self-insurance, in relation to prudence and validation of an appropriate premium, the following information must be provided:

- substantiation of costs to enable the Regulator and users to determine whether the proposed costs are reasonable;
- a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding notional insurance premiums (to ensure that self-insurance costs are prudent, quantifiable and actuarially determined); and
- a copy of the board resolution to self-insure and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance against and which explicitly acknowledges the assumed risks of this approach.

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75 Epic Energy FDS6, 26 March 2002, p.9.
76 Epic Energy FDS6, 26 March 2002, p.10.
77 Macquarie Bank, *Issue for debt and equity providers in assessing greenfields gas pipelines*, May 2002, p 181.

In addition, the Commission made it clear that should future expenditure be required as a result of an insurance event,[78] such costs would not be recoverable under the regulatory framework. This is because the relevant premiums would have already been compensated for within the 'non-capital costs' element of the allowed tariffs.[79]

2.5.3 Epic's further submission

Epic responded to the Commission's letter of 16 April 2002 as part of its submission concerning the overall compliance of its revised access arrangement with the Code. In FDS4 Epic contends that it has provided significant detail justifying its position with respect to self-insurance and that its proposed approach is not unreasonable.[80] FDS4 raises two issues with respect to Epic's self-insurance proposal. Firstly, the method of compensation (via a premium on the cost of capital rather than through an allowance in non-capital costs), and secondly, quantification and additional information required by the Commission.

As noted previously, in FDS6 Epic proposed to add a premium to the return on equity to compensate for self-insurance costs, and cited previous regulatory decisions as precedent for such an approach. Epic maintained in FDS4 that such an approach was reasonable. Epic referred to an extract from the Commission's *Final Decision* for the Central West Pipeline to support its justification on the basis of regulatory precedent.[81]

The second issue Epic raised in FDS4 with respect to self-insurance was the requirement for further quantification and information in support of Epic's self-insurance claim. Epic submitted that additional information would not give further credibility to either its own position or the Commission's approach.[82] Epic's reasoning was due to the difficulty in quantifying such risks and that the veracity of the calculations would always be in doubt.[83] Epic claimed that this was demonstrated through a report prepared by Trowbridge Consulting for SPI PowerNet on the valuation of non-insured risks.[84]

Epic stated in FDS4 that it did not intend to provide the information requested by the Commission in its letter of 16 April 2002 in relation to self-insurance. However Epic also stated that it was prepared for FDS6 (which was originally confidential) to be made public.[85]

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78 An insurance event refers to an event that triggers an insurance claim, including a notional claim in the case of self-insurance.

79 This is also the case for expenditure arising from conventional insurance claims where users have already funded the insurance premiums.

80 Epic Energy FDS4, 2 July 2002, p.44.

81 Epic Energy FDS4, 2 July 2002, p.44.

82 Epic Energy FDS4, 2 July 2002, p.45.

83 Epic Energy FDS4, 2 July 2002, p.45.

84 Epic Energy FDS4, 2 July 2002, p.45.

85 Epic Energy FDS4, 2 July 2002, p.45.

2.5.4 Commission's considerations

The Commission has assessed Epic's proposal to self-insure against certain risks. The Commission considers that there are a number of elements to Epic's proposal that render it inconsistent with the Code. Epic was given ample opportunity to amend its proposal in response to the Commission's letter to Epic of 16 April 2002 that detailed the inadequacies of Epic's proposal with respect to the requirements of the Code. The letter sent to Epic on 16 April 2002 is consistent with the findings of the Draft Greenfields Guideline, released on 25 June 2002. The section of the Draft Greenfields Guideline relating to self-insurance is replicated below.

> In common with mature pipelines, greenfields projects face a number of specific risks that may impinge on cash flow returns available to the venture. Because such risks are non-systematic it is inappropriate to try to reflect such risks in the asset beta established for the regulatory framework. The ACCC maintains that such risks should be compensated for in the cash flow analysis.
>
> As noted above, prudently incurred insurance costs can be included in the operations and maintenance costs (O&M) of the pipeline. Similarly, when an operator chooses to self-insure for non-systematic risk, the prudent premium may be included in the calculation of the revenue requirement.
>
> The ACCC understands that a service provider contemplating assuming self-insurance risk would ordinarily conduct a detailed risk analysis to satisfy debt provider and/or corporate governance requirements. Such analysis is likely to include an assessment of the particular risk/s involved, the impact on the business and its cashflow should the event occur and the probability of occurrence.
>
> Accordingly, for a regulator to adequately assess a proposal for self-insurance, in relation to prudency and validation of an appropriate premium, it would need to consider such matters as: a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums; confirmation of the board resolution to self-insure; and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for.
>
> A regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring. In the event of future expenditure required as a result of an insurance event[86] such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operations and maintenance element of the allowed tariffs and funded by users.[87]
>
> Therefore, where the risk is self-insurable and assumed by a service provider, one approach for compensating the service provider would be to adopt a fair actuarially determined insurance premium for each specific risk and include these as part of O&M forecast expenditures.
>
> The following are key parameters required to model self-insured events as part of the cash-flow analysis.

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[86] An insurance event refers to an event, which triggers an insurance claim, including a notional claim in the case of self-insurance.

[87] This is also the case for expenditure arising from conventional insurance claims when users have already funded the insurance premiums.

- The realistic estimates of the likely occurrence of each type of event. Some probabilities will depend on the age, operating pressure of the pipeline etc. and these can be reflected as time or volume dependent probabilities.

- The expected financial impact of the event, which may be technical or related to legal liabilities. Again such costs must be realistic, for example the cost cannot credibly exceed the asset value of the company at the time of occurrence.

This is precisely the same information required to actuarially determine insurance premiums from a third party perspective but without the truncation of liabilities or risk abatement strategies available to the pipeline company.

The section below details the Commission's consideration of Epic's self-insurance proposal.

Detailed quantification of self-insurance categories and costs

While Epic has agreed to make its self-insurance proposal public, there is insufficient quantification and identification of the actual risks Epic intends to self-insure against to enable proper scrutiny of Epic's proposal. Epic has not provided a break down of various risks it is proposing to self-insure against, their impact on cash flows, and associated probability of occurrence that would lead to the calculation of a reasonable insurance premium.

Epic contends that such risks are difficult to quantify and has therefore provided no quantification of its proposed self-insurance costs except to propose a total premium that should be added to the return on equity. The Commission notes that other service providers have in fact sought actuarial reports on the cost of self-insurance. Notwithstanding any judgement the Commission may make on the individual actuarial reports submitted, the Commission notes that such reports enable appropriate scrutiny of the cost calculations and detail the various categories of risk for which self-insurance is proposed.

While the risks may be difficult to quantify precisely, quantification from an industry expert would be more veracious than the unsubstantiated premium proposed by Epic in FDS6. It is not evident that the premium proposed by Epic is based on an assessment of the factors that a reasonable insurance premium would be based upon. Moreover, it is unclear what risks Epic's proposed premium is intended to cover.

Without such detail, aside from not being able to adequately assess a self-insurance proposal, regulators would be unable to prevent users from exploitation through double dipping by service providers in future operational and capital expenditure claims. That is, a user could be forced to pay the service provider for its self-insurance costs, and then be forced to pay for expenditure that may arise from an insurance event as there would be insufficient knowledge of the insurance funding already provided by the user.

Given the real risk of such a scenario, the Commission considers that Epic's approach does not meet the requirements of section 2.24 of the Code, specifically, the interests of users and prospective users.

Board resolution to assume the risks of self-insurance

Epic did not obtain board resolution to assume the risks of self-insurance, nor did it submit to the Commission that such a requirement was unreasonable or inappropriate. The rationale for such a board resolution is directed at preventing double dipping and future disputes if an insurance event occurs, for which self-insurance cover has been funded. The Commission considers that board resolution to self-insure is an appropriate safeguard against service providers distancing themselves from existing regulatory arrangements in the case that an insurance event causes substantial loss.

Compensation via a premium on the return on equity versus explicitly through non-capital costs

Epic proposed compensation for self-insurance through a premium on the return on equity. Epic claimed that this approach was consistent (at least in part) with the precedent of the Commission's decisions for the Central West Pipeline and for the Victorian Pipelines. The betas selected included a premium to account for an amount of compensation for self-insurance risks. It was however stated in the Victorian *Final Decision* in 1998 that if the quantification of self-insurance costs had been credible, there would have been a reasonable case for including such costs in the revenue requirement.

Epic has justified compensation via a premium on the return on equity rather than through non-capital costs on the basis of the uncertainty in the costs of insurance.[88] However, such an approach does not address the issue of the appropriate premium to be added. Such an approach only serves to make the allowance for self-insurance less transparent.

The letter to Epic of 16 April 2002 stated that compensation for self-insurance should be explicit in the non-capital costs that form part of the revenue requirement. In additional to quantification issues, as outlined above, such a premium would undermine the integrity of the CAPM, which is inconsistent with the Code. This approach is also advocated in the Commission's Draft Greenfields Guideline.

Conclusion

It may be appropriate and consistent with the Code for a prudent service provider to self-insure against certain risks in certain circumstances. However, Epic's specific proposal is not acceptable when considered in light of the section 2.24 factors set out in the Code.

The Commission believes that Epic's proposal is inconsistent with the factors that the Commission must consider under section 2.24 of the Code, including section 2.24(f), the interests of users and prospective users. This is in part due to the fact that the lack of transparency and quantification in Epic's approach would not enable the Commission or users to ensure that there is no 'double-dipping' with respect to self-insurance and future capital and operational expenditure. Moreover, the lack of identification and quantification of the risks for which self-insurance is proposed

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[88] Epic Energy FDS6, 26 March 2002, p.9.

prevents both the Commission and interested parties from assessing the reasonableness of Epic's proposal.

2.6 Conclusion: revised access arrangement does not comply

The Commission is not satisfied that Epic's revised access arrangement incorporates several significant amendments specified in the *Final Decision* or that the changes satisfy the Commission's reasoning for requiring those amendments.

Pursuant to section 2.19 of the Code, the Commission does not approve the revised access arrangement.

3. The ACCC's Access Arrangement for the MAPS

Section 2.20(a) of the Code provides that if the Regulator does not approve the revised access arrangement it must draft and approve its own access arrangement. The Commission has drafted its own access arrangement for the MAPS.

In drafting its access arrangement, the Commission has sought to maintain the access arrangement as proposed by Epic as much as possible. The Commission has made only those changes to the access arrangement which are required to comply with the *Final Decision*: the access arrangement document retains the same structure and content (subject to the Commission's amendments) as that produced by Epic as its revised access arrangement.

The Commission's access arrangement for the MAPS is available from the Commission's website: http://www.accc.gov.au.

4. Final Approval

For the reasons expressed in this document and the *Final Decision*, the Commission has decided to approve its own access arrangement for the MAPS under section 2.20(a) of the Code.

4.1 Commencement Date

Section 2.26 of the Code provides that decisions made by the Commission under section 2.20(a) are subject to review by the Australian Competition Tribunal under the Gas Pipelines Access Law. For this reason, an access arrangement drafted and approved by the Commission cannot commence for at least 14 days after the decision to approve it is made.

Subject to the Code and the Gas Pipelines Access Law, the access arrangement approved by the Commission has affect from 15 August 2002.

Annexure 1

Public version of response to Epic Energy's Final Decision Submission # 3

[Sections 1 to 4 are confidential and have been deleted.]

5. The Regulatory Framework – Possible Remedies for Stranding Risk

The Commission has established that the MAPS faces stranding risk from 2006 (albeit temporary and partial stranding), and that stranding risk is a specific risk and therefore should not be compensated through inflating the cost of capital via the asset beta. This section presents the mechanisms available under the regulatory framework for addressing stranding risk without corrupting the CAPM. These mechanisms allow for the specific circumstances of the MAPS to be taken into account.

5.1 Flexibility through depreciation

The Code allows for a great deal of flexibility through the potential approaches that can be adopted for regulatory depreciation. Under the Code a depreciation schedule should reflect the following principles:[89]

- the change in reference tariffs over time is consistent with the efficient growth of the market for the services provided;
- depreciation occurs over the economic life of the asset(s) with progressive adjustments where appropriate to reflect changes in expected economic lives; and
- an asset is depreciated only once and that total accumulated depreciation will not exceed the valuation of the asset when initially incorporated in the capital base.

Standard straight-line depreciation over the economic life of the asset has typically been the method used when depreciating a pipeline's capital base. However, provided that the principles of the Code are adhered to, a service provider is able to choose a different depreciation profile.

For example, the Commission's Central West Pipeline[90] (CWP) *Final Decision* provided for the use of economic depreciation as part of the service provider's NPV/price path methodology to determine total revenue. Economic depreciation was calculated in the following manner:

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89 Refer Code section 8.33.

90 Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline *Final Decision*, 30 June 2000.

Economic depreciation = total revenue – operating costs – return on capital

The Commission approved, with qualifications,[91] the service provider's proposed economic depreciation approach in recognition of the beneficial effect it would have in allowing the service provider to recoup under-recoveries accrued in the early period of the life of the CWP. This approach also provided lower tariffs during the initial phase of the life of the CWP, enabling greater opportunities for market development.

This approach to depreciation was considered consistent with the Code objective that the service provider should have the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference services over the expected life of the assets.[92] In addition, it is particularly helpful for new pipeline developments where full cost recovery would imply high initial tariffs and consequently poor take-up of available capacity. The approach means that the company can charge lower tariffs initially and encourage gas usage without incurring a non-recoverable financial loss.

5.2 Accelerate depreciation prior to stranding

The Commission's preferred approach to deal with stranding or by-pass risk is to set a depreciation profile that gives rise to cost of service based prices that behave as if the industry were contestable.[93] This involves making adjustments to reflect the impact of future potential stranding of identified assets (that is possible redundant assets). A similar approach was adopted in the Commission's *Draft Decision* for the Amadeus Basin to Darwin Pipeline where there was a risk of stranding.[94] However, such an approach is not possible for the MAPS in the initial access arrangement period due to capacity being fully committed under contract. [Sentence deleted due to confidentiality] Therefore, while available, such an approach may not be Epic's preference.

5.3 Calculate tariffs using agreed throughput forecasts

The Code's approach to demand risk differs from the 'defined capacity' approach adopted by the FERC in regulating gas transmission pipelines in the US. Under a defined capacity approach reference tariffs are based on the pipeline's capacity rather than forecast volumes. *Ceteris paribus*, 'defined capacity' reference tariffs are likely to be lower than if forecast demand is used, particularly in the initial stages of the life of a pipeline that has been built with excess capacity in the expectation of future demand growth. Compared with the US approach, the Code provisions facilitate the transfer of some of this demand risk away from a prospective service provider to customers.

Sections 8.38 to 8.41 of the Code provide the principles for allocating revenues (costs) technically between services. The section 8.38 requires that, to the maximum extent that is commercial and reasonable, reference tariffs recover all costs directly attributed to the reference service and a fair and reasonable share of joint costs. In addition, section 8.38 provides for the calculation of reference tariffs based upon forecasts. As

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91 Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline *Final Decision*, 30 June 2000, p.68-72.

92 Refer Code section 8.1(a).

93 Statement of Principles for the Regulation of Transmission Revenues, May 1999 Annex 5.1.

94 See the Commission's *Draft Decision* for the Amadeus Basin to Darwin Pipeline, 2 May 2001.

such the Commission has calculated tariffs using agreed forecast demand, supplied by Epic, rather than pipeline capacity.[95]

The method used by the Commission for calculating tariffs from the revenue requirement should compensate Epic sufficiently for partial or temporary stranding of the MAPS, should that eventuate. Section 8.3 of the Code enables a flexible approach to reference tariffs based on:

> (a) a "price path" approach, whereby a series of Reference Tariffs are determined in advance for the Access Arrangement Period to follow a path that is forecast to deliver a revenue stream calculated consistently with the principles in this section 8, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period;
>
> (b) a "cost of service" approach, whereby the Tariff is set on the basis of the anticipated costs of providing the Reference Service and is adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the Tariff recovers the actual costs of providing the Service; or
>
> (c) variations or combinations of these approaches.

Specifically, section 8.3 (b) gives discretion to the service provider in how tariffs are to be adjusted in the light of actual outcomes. Therefore, should expected volume decrease, the tariffs approved by the Commission may increase such that the required revenue is still achieved subject to the requirements of section 8.1 of the Code.

[Paragraph deleted due to confidentiality]

5.4 Alter depreciation profile – capitalise short/medium term losses

The Commission has indicated in chapter 5 of the *Draft Regulatory Principles* that a service provider can propose a variety of depreciation profiles. Examples include accelerating depreciation in advance of asset stranding, or at the other extreme ‘backend loading’ depreciation. A backend loaded depreciation profile would have the effect of lowering tariffs initially by deferring the ‘return of capital’ building block until later years. While the depreciation profile chosen is subject to regulatory approval, the Commission is unlikely to reject a reasonable proposal subject to the constraint that the asset is only depreciated once.

[Paragraph deleted due to confidentiality]

…any net under-recovery is termed ‘economic depreciation’, which is negative. An economic depreciation approach is intended to allow a service provider to subsequently recoup these under-recovered revenues and have the opportunity to earn a revenue stream that covers efficient costs over the life of the asset.

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[95] Tariffs have been calculated using Epic’s nominated load factor for the commodity tariff, and the system primary capacity as defined by Epic for the capacity charge as the pipeline is fully contracted for the first access arrangement period.

The methodology results in negative depreciation during the first phase, which has the effect of increasing the asset value for regulatory purposes. This is described in the section 8.34 (a) of the Code:

> … the notional depreciation over the Access Arrangement Period for each asset or group of assets that form part of the Covered Pipeline is:
>
> (a) for an asset that was in existence at the commencement of the Access Arrangement Period, the difference between the value of that asset in the Capital Base at the commencement of the Access Arrangement Period and the value of that asset that is reflected in the Residual Value;

The residual value at the end of the initial access arrangement period would be greater than the initial capital base at the start of the period. Similarly, the regulatory asset base would be greater than the actual cost of the assets as a result of negative economic depreciation in the first period of operation.

Therefore, if Epic envisages its revenue requirement as unattainable in future regulatory periods even when taking section 5.3 of this paper into account, it should elect to change its regulatory depreciation profile. The economic depreciation profile would enable losses to effectively be capitalised until such time that higher tariffs are achievable or more likely, until pipeline utilisation is increased. Once again, this ensures the objectives of sections 8.1 and 8.3 of the Code are met.

6. Conclusion

This paper has reviewed the response by Epic to the Commission's confidential Annexure 2 to the *Final Decision*. After giving due consideration to Epic's arguments in FDS3 and the Commission's established methodology for determining reference tariffs, the Commission has concluded that the requirements of the Code, including sections 8.1 and 2.24, are met through the following:

- Epic (and indeed any regulated service provider) should not be compensated for non-systematic stranding risk via a higher cost of capital. In this case, Epic was seeking a higher value for the CAPM's systematic risk measure, beta.
- The value of the asset beta should not be changed from 0.5 as set out in the Commission's *Draft Decision, Final Decision* and *Final Approval*.

The mechanisms outlined in section 5 of this paper are available if, at some future time, there is a need to deal with genuine stranding or bypass risk.

Annexure 2

Public version of Modelling changes since the Commission's Final Decision

[Note: some text has been deleted due to confidentiality.]

1. Purpose

This paper documents the changes to the Commission's revenue model, made since the Commission's *Final Decision* in September 2001. All but one[96] of the changes have been discussed with Epic and its consultant. In many cases, the changes have been previously documented through an exchange of letters between the Commission and Epic. This paper consolidates the changes to the model into one document, referencing changes to earlier correspondence where applicable.

2. Specific modelling changes

2.1 Book depreciation for operations and maintenance facilities

As noted in Epic's letter of 20 December 2001, the figure for book depreciation of operations and maintenance facilities for 1999 was incorrectly entered into the revenue model. The number has been changed as confirmed in the Commission's letter of 21 December 2001.

2.2 Asset class to be used to calculate half-year depreciation in establishing 1 January 01 DORC from 30 June 01 DORC

This issue was noted in Epic's letter of 20 December 2001. In the second step in moving DORC from 30 June 2001 to 1 January 2001 where half a year of depreciation was added back, the depreciation was calculated using the remaining asset life for the pipeline rather than separate remaining asset lives corresponding to each asset class. The Commission however agrees with Epic, that this calculation should be done using the relevant remaining asset life rather than that of the pipeline class. This change has been implemented in the revised tariff model.

2.3 Tax depreciation methodology: straight-line or diminishing value

As requested in Epic's letter of 14 January 2002, the Commission has changed the revenue model such that tax depreciation is calculated using a straight-line method. This was acknowledged in a letter from the Commission to Epic of 16 January 2002.

2.4 Depreciation rates for tax-depreciation and Tax Ruling TR2000/18

In its response of 16 January 2002 to Epic's letter dated 14 January 2002, the Commission acknowledged that different depreciation rates apply to capital

[96] See section 1.2.6 of this annexure.

expenditure pre and post September 1999 as a result of TR2000/18. The Commission sought a breakdown of the value to be assigned to the old rate and to the new rates. Epic did not provide the requested information. In the absence of the requested information, the Commission has applied the new depreciation rates to forecast capital expenditure from 2001 onwards. Specifically, the Commission has used the table below provided by Epic in its letter of 14 January 2002 to calculate tax depreciation. The 'before 21/9/99' data was applied to existing capital and 'after 21/9/99' data for new capital expenditure from 2001 onward.

	Useful Lives of Assets Acquired	
Asset Class	Before 21/9/99	After 21/9/99
Pipelines	8	20
Compressors	8	20
Meter stations and regulators	8	13
SCADA	4	4
Communications	8	7
Maintenance capital	8	20
Spares	8	20

2.5 Remaining asset lives for the calculation of DORC and regulatory depreciation

In its response of 21 December 2001 to Epic's letter of 20 December 2001, the Commission stated that it would use the remaining asset lives pending the review of remaining asset lives to be undertaken by Epic. Epic included the table below in its letter of 14 January 2002.

Asset Class	**Average Expended Life 30 June 2001** (years)	**Average Remaining Life 30 June 2001** (years)	**Average Remaining Life 1 January 2001** (years)
Pipeline	Confidential	Confidential	Confidential
Compressor stations	Confidential	Confidential	Confidential
Meter stations and regulators	Confidential	Confidential	Confidential
SCADA	Confidential	Confidential	Confidential
Communications	Confidential	Confidential	Confidential
Maintenance depot, HO, etc.	Confidential	Confidential	Confidential
Spares	Confidential	Confidential	Confidential

Assume replacement at end of economic life.

The Commission noted in its reply of 16 January 2002, that it would use the 30 June 2001 figures for calculating DORC, and the 1 January 2001 figures for calculating regulatory depreciation.

2.6 Revenue smoothing

The Commission's revenue model contains a smoothing module to remove fluctuations in the annual revenue requirement, while maintaining equivalent net present values (NPVs) over the modelling period. At the time of the *Final Decision*, equivalent NPVs were determined for the unsmoothed revenue and Epic's elected escalation profile (95 percent of CPI). However, the NPVs were calculated inclusive of 2006 rather than to the end of 2005. This has now been rectified, resulting in a minor increase in Epic's smoothed revenue requirement. This modelling change has not previously been discussed with Epic.

3. Revenue to tariffs

Since the *Final Decision*, the Commission has constructed a model to calculate the various tariffs for the MAPS from the revenue determined by the revenue model. The tariff model was built to replicate the tariffs proposed by Epic in its revised access arrangement of 22 January 2002. The process used to calculate tariffs for the MAPS was set out in a series of dot points by Epic in its FDS5, section 2.4.2.

The Commission constructed a model using this information and with the assistance of Epic's consultant through a series of telephone conversations between 19 and 21 March 2002. It should be noted that Epic's tariff calculations must be replicated using the information contained in the confidential version of the access arrangement information of 11 September 2000, as the required information is not presented in the public access arrangement information.

Annexure 3: Confidential

Response to Epic Energy's Final Decision Submission # 3

See annexure 1 for a public version of this annexure.

Annexure 4: Confidential

Modelling changes since the Commission's Final Decision

See annexure 2 for a public version of this annexure.

Annexure 5:

Commission ORC Anylsis

1. Introduction

Epic originally submitted an ORC estimate for the MAPS of $572,000,000 (in 1998 dollars) based on its Option B, which had the lowest cost of four pipeline options Epic had costed in its optimising study. Option B consisted of a main pipeline of 558mm diameter (22 inch) operating at a pressure of 15 MPa.[97] All four options were considered by Epic to provide similar capacity and redundancy to the existing system and were based on a maximum capacity of 393 TJ/day.

Since the *Final Decision*, Epic has submitted revisions to its original ORC costing. In the case of Option B, which is still its lowest cost option, the ORC cost has increased to $602,000,000 (in 1998 dollars).[98]

Epic's revisions are as follows:

- laterals have increased from $46,703,304 to $55,590,984 (correcting partly for an error in Epic's original estimate but still including a 4-inch strap-on pipe across Spencers Gulf, the latter is not justified and overstates the cost by $5 million), and
- interest on capital has increased from $33,800,000 to $57,000,000 following changes to the method of determining it and an extension of the construction period from 18 to 24 months.

Epic's revised costing is set out in the table on the following page.

Epic has recently provided further comment in support of its approach to estimation of ORC. It states: [99]

> In developing its approach to estimating the optimised replacement cost of the pipeline installation Epic:
>
> - undertook a rigorous analysis of the pipeline hydraulics to determine an appropriate physical design and;
>
> - allocated costs against the designs at "all in" unit rates based on Epic's understanding of the total pipeline development cost current at the time of the estimate.
>
> While the use of "all in" costs is a somewhat simplistic approach to cost estimating for a large project, it is also well recognised in the industry as a sound basis for establishing a reasonable cost estimate. It is noted that the Commission does not

[97] Revised Access Arrangement Information for the MAPS, 20 March 1999, Attachment 2, p 23.
[98] Revised Access Arrangement Information for the MAPS, 22 January 2002, Attachment 2, p 22.
[99] Epic, FDS4, 2 July 2002, p 34.

> require the proponent to undertake a detailed project budget level estimate to establish the project capital base.
>
> Alternative methods, including the "all in" approach are appropriate when the source of the "all in" data is from projects located in similar topography, of similar size, and relevant in time.

In FDS4 Epic also submits that:

> Epic Energy has designed and constructed a number of transmission pipelines, including one of the first long distance ANSI Class 900 pipelines in Australia. The "all in" costs used by it are based on an analysis of actual project costs. The actual cost for construction of the Ballera to Wallumbilla (Qld) pipeline is relevant because its design, characteristics and environment is similar to that for the Moomba to Adelaide pipeline.[100]
>
> Epic Energy's Ballera – Wallumbilla pipeline, (whose length and design and the terrain over which it is constructed is similar to the MAPS) cost $20,200 per inch per km in 1996 dollars.[101]
>
> Both these factors suggest that the value of $22,000 per inch km in 2000 dollars[102] is a reasonable basis for developing a proper valuation of the capital cost of the pipeline.

Epic's submissions are considered and assessed below.

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100 Epic, FDS4, 2 July 2002, p 38.
101 Epic, FDS4, 2 July 2002, p 36.
102 Epic has quoted year 2000 dollars here, but the context suggests it could mean end year 1998 dollars.

Highlighted area denotes change from April 99 doc

ITEM / DESCIPTION	Option A				Option B				Option C				Option D				
	Unit	Pipeline Diameter	Unit Cost	Cost	Unit	Pipeline Diameter	Unit Cost	Cost	Unit	Pipeline Diameter	Unit Cost	Cost	Unit	Pipeline Diameter	Unit Cost	Cost	
PIPELINE	km	inch	$/inch.km	$	km	inch	$/inch.km	$	km	inch	$/inch.km	$	km	inch	$/inch.km	$	
Main Line	781	22	22,000	378,004,000	781	22	22,000	378,004,000	781	34	22,000	584,188,000	781	24	22,000	412,368,000	
Loop Line	42	20	22,000	18,480,000	42	20	22,000	18,480,000	42	20	22,000	18,480,000	42	20	22,000	18,480,000	
Laterals – see item 1 above	244.48			46,325,820	244.48			55,590,984	244.48			46,325,820	244.48			46,325,820	
Allowance Native Title Compensation				5,270,000				5,270,000				5,270,000				5,270,000	
COMPRESSORS	K W		$/kW	$	K W		$/kW	$	K W		$/kW	$	K W		$/kW	$	
Compressor Station # 1	6,000		3,000	18,000,000	18,000		2,000	36,000,000	0			0	9,000		2,500	22,500,000	
Compressor Station # 2	6,000		3,000	18,000,000					0			0	9,000		2,500	22,500,000	
Compressor Station # 3	6,000		3,000	18,000,000					0			0					
Compressor Station # 4	6,000		3,000	18,000,000	4000		2500	10,000,000	0			0					
Compressor Station # 5	6,000		3,000	18,000,000					0			0					
Compressor Station # 6	6,000		3,000	18,000,000					0			0					
Compressor Station # 7	6,000		3,000	18,000,000					0			0					
Whyte Yarcowie Compressor Station	570		5,000	2,850,000	1140		5,000	5,700,000	0			0	1140		5,000	5,700,000	
METER STATIONS																	
Meter & Regulation Stations – see item 6 above				16,400,400				16,400,000				16,400,400				16,400,400	
SCADA, COMMUNICATIONS																	
SCADA & Communications – see item 2 above				7,000,000				7,000,000				7,000,000				7,000,000	
LINE PACK	GJ		$/GJ	Cost	GJ		$/GJ	Cost	GJ		$/GJ	Cost	GJ		$/GJ	Cost	
	502,710		2.75	1,382,453	1,000,020		2.75	2,750,055	777,000		2.75	2,136,750	800,000		2.75	2,200,000	
OPERATIONS & MAINTENANCE																	
Maintenance Depot – see item 4 above				6,000,000				6,000,000				6,000,000				6,000,000	
Spares– see item 4 above				3,500,000				3,500,000				3,500,000				3,500,000	
Head Office / Gas Control– see item 4 above				3,500,000				3,500,000				3,500,000				3,500,000	
SUB-TOTAL				**$ 614,712,672.50**				**$ 548,195,039.00**				**$ 692,800,970.00**				**$ 571,744,220.00**	
Interest on Capital (see item 7 above)				**$ 58,300,000.00**				**$ 51,900,000.00**				**$ 65,700,000.00**				**$ 54,200,000.00**	
(average of the amounts)																	
SUB-TOT (FOR DEPRECIATION PURPOSES)				**$ 673,012,672.50**				**$ 600,095,039.00**				**$ 758,500,970.00**				**$ 625,944,220.00**	
GAS QUALITY																	
Gas Quality Monitoring – see item 5 above				600,000				**$ 600,000.00**				600,000				600,000	
REMOTE CONTROL																	
Remote Valves – see item 4 above				1,250,000				**$ 1,250,000.00**				1,250,000				1,250,000	
GRAND TOTAL				**$ 674,862,672.50**				**$ 601,945,039.00**				**$ 760,350,970.00**				**$ 627,794,220.00**	
				$ 675	**Million**			**$ 602**	**Million**			**$ 760**	**Million**			**$ 628**	**Million**

2. General discussion of Epic's overall approach

Epic has not provided details of its hydraulic analysis to determine an appropriate physical design and as can be seen, used 'all in' costs to establish its cost estimates.

With regard to Epic's hydraulic analysis, the Commission's consultants were able to readily confirm the suitability of the configurations chosen by Epic for each option – at least in a general sense. This aspect of Epic's proposal has not been questioned. (Inevitably, given the lack of detail and the Commission's assumption of a higher design maximum capacity of 418 TJ/day, slight differences in outcomes have emerged as discussed in subsequent sections).

On the other hand there is some concern with Epic's use of 'all in' costs. This is illustrated by consideration of the unit costs Epic adopted for the mainline (see table above), for which it used a uniform rate of $22,000/km.inch for all four options it presented, regardless of differences between the maximum design pressure of each option. Epic partly addressed this insensitivity to varying design pressure conditions of its use of an 'all in' unit rate by increasing the unit rate, but only for lateral pipelines, and only for Option B that has the highest design pressure rating (15MPa) of all the options considered.

Establishing the appropriate value for the initial capital base, of which the ORC is an important input, is one of the key determinants in the allowable revenue. Also, under the Code, the initial capital base may not be reviewed in subsequent revisions. Given the importance of ORC under these circumstances, its estimation deserves due process and a proponent should provide sufficient information on its cost estimate to enable a proposal to be assessed adequately by both interested parties and the regulator.

Just what is "sufficient" information is a matter of judgement and the Commission has avoided detailed prescription in this regard, preferring to leave the actual approach to a proponent's discretion. To date, in the case of all access arrangement proposals for similar systems, significantly more detailed costing models were provided to the Commission and (generally) to interested parties than by Epic in this case. In particular, more detailed information was provided for assessment of access arrangements for the TPA/Gasnet Victorian system, the Moomba to Sydney system and the Amadeus Basin to Darwin pipeline system.

In the examples cited above, the approach adopted by the proponents was different in each case, but these applications provided significant supporting detail to allow a proper assessment of the proponents' cost estimates, at least in the first instance.

In the case of the MAPS, Santos and TGT, two interested parties with some knowledge of the industry[103] expressed concern that Epic's capital cost estimates were too high (by 8 percent to 20-22 percent). On the other hand, Epic and its consultants took the view, which Epic has repeated in the above citation, that its cost estimate was appropriate and apart from the recent relatively minor modifications it has not sought to vary its model or approach to any great extent nor to provide additional supporting detail. Epic

103 See comments of Santos and TGT reported in section 2.2.3 of the *Draft Decision*.

appears unwilling to commit itself to a final figure for ORC as evidenced by its following statement: [104]

> The optimised replacement cost ("ORC") value of the pipeline lies in the range of $590 million to $620 million (June 2000 dollars), although if the full impact of exchange rate variations were to be taken into account, the valuation would increase by a further minimum $55 million.

In the circumstances, a more detailed validation of the ORC is required. In the absence of further details being provided by Epic, the Commission sought consultant's reviews of key elements of the costing and undertook an in-house review.

3. General discussion of the Commission's overall approach

For the Commission's *Draft* and *Final Decisions,* both Connell Wagner and its in-house consultant considered the four pipeline options costed by Epic and confirmed Epic's hydraulic analysis. In reviewing the cost of each option, the one estimated by both consultants to have the lowest capital cost was determined to be the optimum configuration. [105] This was one based on Epic's Option D, not Option B. As can be seen in Epic's table reproduced above, Option D consists of a main pipeline of 610mm diameter (24 inch) operating at a pressure of 10 MPa.

In its *Final Decision* the Commission assumed a maximum capacity of 418 TJ/day for the MAPS. When applied to Option D, this resulted in a modified compressor station configuration over that required for 393 TJ/day, with increased total installed power and some other relatively minor changes. The implications of this assumption are discussed in greater detail below.

The ORC adopted by the Commission for the *Final Decision* was $624,900,000 (in June 2001 dollars).

Like the approach adopted by Epic, the estimate adopted by the Commission also relied on unit rates but over a greater number of variables. Unlike Epic's use of a single 'all in' rate, particularly for the pipelines component,[106] separate unit rates were used to estimate the cost of each of the main elements determining total pipeline cost. These elements included easement acquisition, material procurement (including the cost of pipe and coating), transport, construction and installation costs.

The pipeline was divided into over 100 segments to more accurately differentiate the mainline from the loop line, Spencers Gulf and other water crossings and lateral pipelines and to take some account of assumptions about differing terrain and trenching conditions.

Like Epic, separate unit rates and assumptions were also made for other major cost items such as compressor and meter stations, SCADA, linepack and operations and maintenance facilities. Separate allowances (determined by way of an assumed

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[104] Epic, FDS 4, 2 July 2002, p 33.
[105] It had also the lowest NPV after fuel and operating costs were considered.
[106] The mainline represents approximately 68% of Epic's total ORC.

percentage of cost totals) were included for indirect costs such as EPCM,[107] overheads and spares. (For the *Draft* and *Final Decisions*, to allow comparison on a line by line basis with Epic's ORC estimate, these allowances were re-apportioned among the main cost items.)

Epic has recently proposed a different method for determination of interest on capital during construction that the Commission has accepted in part. This is discussed below.

In the following section, a more detailed comparison of the ORC estimates is provided as well as a discussion on appropriate recognition of CPI and exchange rate variations. A final section summarising the main conclusions of this report follows this.

First, however, it is useful to discuss Epic's comments with regard to the lack of an overall contingency allowance in the Commission's estimate and Epic's view that a similar allowance is not required in its approach.

4. Contingencies

In its most recent submission, Epic makes the following contention with regard to contingencies: [108]

> The Commission's estimate is considered to be at the low end of the range of costs for a new pipeline project. This is largely a result of an insufficient allowance for the costs that are not included in the unit materials and construction costs adopted by the ACCC, and the absence of a significant contingency to account for these omissions.
>
> Because the cost items identified in the Commission's estimate typically account for a large percentage of the capital cost of a pipeline project, there is a tendency to assume that the allowance provides for the numerous smaller cost items that are not part of the assumed unit costs (that is, there is no provision for omissions from the estimate).
>
> A Commission spreadsheet provided for review summarising its view of the Epic Energy ORC did not include any contingency for omissions. This appears to be consistent with the Commission's treatment of the capital cost estimate prepared for the EAPL Moomba to Sydney ORC, where the contingency provided for omissions was deleted.
>
> Epic Energy considers that it is wrong for any estimate to omit an allowance (contingency) for omissions. This amount is separate from any allowance that might be applied by a developer to establish a project financing budget and/or to cover for the level of reliability of an estimate.

Epic also submits that: [109]

> The estimates prepared by Epic Energy are considered to provide a reasonable basis for valuing the ORC of the Moomba to Adelaide pipeline network because the Epic estimate is supported by actual costs of constructing like pipeline projects, and like pipeline facilities.

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107 Engineering, project and construction management.
108 Epic Energy, FDS4, 2 July 2002, p.34.
109 Epic Energy, FDS4, 2 July 2002, p.35.

> Because of this, the "all in" estimate basis used by Epic Energy captures all actual project costs, and should be able to be used with a minimal contingency.

Based on the above citations, Epic appears to distinguish between what could be regarded as:

- a general contingency, that is an allowance that might be applied by a developer to establish a project financing budget and/or to cover the level of reliability of an estimate; and
- a contingency required for omissions.

Epic suggests that with regard to the latter the Commission has erred in either not including a contingency for omissions or deleting one (as in the case for the MSP ORC).

With regard to the EAPL ORC the Commission expressed the view in its *Draft Decision* for the MSP that: [110]

> ..while it may be appropriate for a business to include a contingency factor in its estimates of the projected costs of constructing a new pipeline, this is not the case when determining the regulatory value of an existing pipeline.

Moreover, EAPL stated in its report on the ORC, provided as an attachment to its application,[111] that it had applied a 10 percent contingency factor to all costs, including owners, EPCM and interest charges. This was viewed as a general contingency item (as distinguished by Epic) rather than one necessary to account for omissions. For the reason cited above the Commission did not believe that this was appropriate.

With regard to the estimate of ORC calculated by the Commission for the MAPS, various unit rates and allowances applied in the estimate were based where possible on actual known or reported project costs or for example, as in the case of linepipe, on a consultant's report[112] on currently applicable costs. As such, the rates and other allowances have been 'fine tuned' over time to provide that *total* cost estimates based on these rates align with *reported total* costs. Therefore, an explicit allowance for omissions and contingencies would involve double counting, and would in turn, overstate the ORC.

Further, separate estimates, based on unit rates and other factors, were made of the cost of sundry items such as valve and scraper stations, and numerous smaller costs such as joint coating, signs and markers, cathodic protection installation and the like. A separate contingency allowance for such items was therefore not necessary. Having said that, the model used includes a 2.5 percent increment in determining quantities for linepipe, coating and delivery costs.[113] More details of these items are provided in the discussion in the following section.

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110 ACCC: Draft Decision Access Arrangement by EAPL for the Moomba Sydney pipeline system, December 2000, p.29.

111 EAPL, AAI, Attachment F, p.20.

112 MicroAlloying International: *Report on Pricing of High Strength Linepipe*; 7 December 2000.

113 Given that additional pipe is normally ordered to allow for any damage, errors in survey and minor route changes.

Any further allowance for omissions was not considered necessary given the preceding point and the fact that individual unit rates and allowances had been tuned to project outcomes. Epic appears to use a similar argument that its use of “all in” unit rates does not require a contingency allowance.

A better case can be made for a contingency allowance to cover perceived future risk, such as an increase in construction activity affecting the supply of services or a change in the world market for line pipe. As cited above the Commission did allow the inclusion of a general contingency factor in the EAPL application for the MSP and drew a distinction between projecting costs of constructing a *new* pipeline with establishing the regulatory value of an *existing* pipeline.

To ensure that the ORC assessment was representative and fair to all parties, the Commission obtained the opinion of external consultants[114] at various stages in its assessment. Even so, Epic considers the ORC estimate adopted by the Commission to be at the low end of the range of costs for a new pipeline project. However, an ORC should represent an efficient outcome and adding a contingency to an estimate that provides a result at the high end of cost outcomes does not reflect an efficient outcome, nor an appropriate balancing of section 2.24.

5. Comparison of ORC estimates

Table 2.3 in the Commission’s *Final Decision* provided a comparison between Epic’s ORC estimate and that adopted by the Commission.

The Commission’s estimate was carried out as at June 2001 and for the purposes of comparison, Epic’s figures were converted from its original 1998 to 2001 dollar values. A simple CPI factor adjustment was used and the result rounded. (This adjustment is normally employed in benchmark comparisons. It does not necessarily account for the effect, if any, of exchange rate variations. A discussion on this is provided later in this report.)

Table 2.3 is reproduced below and the Commission’s estimate for Option B has been included to provide a better comparison based on similar configurations. The table has been modified to take into account Epic’s revised figures and the CPI adjustment has been applied to those figures. Interest on capital for both Epic’s and the Commission’s estimate, has been revised as discussed later.

114 Connell Wagner, MicroAlloying International, and Sinclair Knight Merz.

Final Decision -Moomba to Adelaide Access Arrangement   Comparison of ORC estimates

	Epic ORC – Option B ($000 June 01)				Commission ORC – Option B ($000 June 01)				Commission ORC – Option D ($000 June 01)			
	MAOP 15MPa - 395TJ/d				MAOP 15MPa - 418TJ/d				MAOP 10MPa - 418 TJ/d			
Item/description	Unit	Diameter	Unit cost	Cost	Unit	Diameter	Unit cost	Cost	Unit	Diameter	Unit cost	Cost
PIPELINE	km	inch	$/inch.km	$000	km	inch	$/inch.km	$000	km	inch	$/inch.km	$000
Main line	781	22	24,100	414,900	781	22	23,100	397,400	781	24	20,100	375,900
Loop line	42	20	24,100	20,300	42	20	25,800	21,700	42	20	25,800	21,700
Laterals	244.5	6.75	37,000	61,000	232.9	7.5	25,600	44,700	232.9	7.5	25,600	44,700
Native title compensation				5,800				5,800				5,800
COMPRESSORS	No	kW	$/kW		No	kW	$/kW		No	kW	$/kW	
Compressor stn #1	3	6,000	2,200	39,500	3	7,690	2,800	65,700	2	4,570	2,300	31,000
Compressor stn #3									2	4,570	3,400	31,000
Compressor stn #4	2	2,000	2,700	11,000	3	4,570	3,200	44,300				
Compressor stn #5									3	4,570	3,000	41,400
WhtyeYarc comp stn	2	570	5,500	6,300								
METER STATIONS												
Meter & regulator stns				18,000				21,800				21,500
SCADA & COMMS												
SCADA & communications				7,700				3,300				3,300
LINEPACK		GJ	$/GJ			GJ	$/GJ			GJ	$/GJ	
Linepack		1,000,000	3.00	3,000		955,000	3.00	2,900		804,000	3.00	2,400
OPERATIONS & MAINTENANCE												
Maintenance depot				6,600				11,900				11,300
Head office/gas control				3,800								
Spares				3,800				5,400				5,100
SUB TOTAL				601,700				624,800				595,100
INTEREST			%				%				%	
Interest on capital			9.5	57,000			6.2	38,700			6.2	36,900
GRAND TOTAL				658,700				663,500				632,000

5.1 Consistency

Epic appears to infer in the following statement that the Commission has allowed a higher 'all in' rate in the case of its EAPL Moomba to Wilton pipeline decision:[115]

> It is noted that the Commission's draft decision for the EAPL Moomba to Wilton pipeline values the ORC of that pipeline at $748.7 million (in 1999 dollars), or an "all in" cost of $30,170 per inch km (including development and owner's costs). This pipeline is a similar design (DN600, Class 900, 1034 km long compared with the Epic Energy 780 km DN 550 Class 900 MAPS).

Comparisons of the cost of different pipeline projects based on unit rates are unreliable given the variables affecting project outcomes.[116] Limitations of the comparison methodology aside, Epic's conclusions are incorrect.

Epic's statement contains a number of errors. The equivalent 'all in' cost of the optimised Moomba to Wilton pipeline (without the contingency but including development and owner's costs) is $821.6 million in 1999 dollars.[117] The optimised Moomba to Wilton pipeline is 1,299 km in length. The correct equivalent 'all in' unit rate is $26,350 per inch km (or $28,828 per inch km after conversion to 2001 dollars).

The Commission's equivalent 'all in' rate for the MAPS Option D is $29,633 per inch km in 2001 dollars, for a lower pressure Class 600 pipeline option.

5.2 Different maximum capacity assumptions

In the Commission's *Draft Decision*, ORC estimates were considered which were based on a maximum capacity for the MAPS of 393 TJ per day.[118] This capacity included an additional 40 TJ per day capacity expansion completed by Epic in early 1999. Epic has since upgraded the capacity of the MAPS by an additional 25 TJ per day. The existing maximum capacity is therefore 418 TJ per day and that capacity is the basis for the Commission's revised ORC.

The pipeline configuration for 393 TJ/day is identical with that required for 418 TJ/day with the exception of the provision of an additional compressor unit at 'Compressor station 5' (see preceding table).

Reflecting this relatively small difference in required configuration, the ORC estimate for 418 TJ/day is $11 million more than that for 393 TJ/day.

5.3 Commission Option D

The Commission has conducted hydraulic analysis and cost estimates. An explanation of the main cost items is provided in the following table[119] and discussion.

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115 Epic Energy, FDS4, 2 July 2002, p.36.

116 See for example the discussion on this topic in GPU Gasnet: Application for Revision to Access Arrangement Southwest pipeline; September 2000, annexure 5, p.39.

117 ACCC: *Draft Decision* EAPL Moomba to Sydney Pipeline System, December 2000, Table 2.2, p.29.

118 MAPS Access Arrangement Information, Attachment 2 (September 1988, revised March 1999).

119 All costs are in 30 June 2001 dollars.

Pipeline cost inputs for Commission's ORC estimate

Item	Rate	Comment
Construction cost base rate Used for determining cost of construction. This base rate is multiplied by factors which vary with the nature of the terrain and trenching conditions and to the total so calculated is added an allowance for joint coating. For this estimate the multiplier is on average equivalent to a factor of 1.3, ie. The overall construction unit rate is equivalent to $342/km.mm. Cathodic protection and pipeline instrumentation is included in this estimate under pipeline construction but are separately derived (see below).	$261/km.mm. $342/km.mm equivalent overall rate.	The overall rate of $342/km.mm is the same value for an overall unit construction rate that Epic's consultant Venton[120] says is more representative of the proper value to use and which was the result of Epic's Ballera-Wallumbilla pipeline constructed in 1996. (That was $306/km.mm in 1996). To allow for inflation to 30 June 2001the unit rate was multiplied by a CPI ratio of 133.8/119.8). Hence, in effect Epic's recommended rate was adopted.
Base pipe cost Cost of steel pipe. Uses a steel grade factor to adjust individual section costs for differences in grade. A spare pipe allowance of 2.5% is included.	$1,120/tonne.	Based on MicroAlloying report for X70 pipe ex Greece of $1,053/tonne @ 54 US cents/$A. Adjustment to $US =$A0.5075 gives $1,120. Typically, prices in January 2001 for relatively small batches of X70 pipe (323.9mm diameter) were $1,015/tonne ex Wollongong.
Pipe delivery Covers cost of delivery and stringing of pipe to and from coating plant to site.	$30 to $150/tonne.	This varied depending on location. The average rate was $80/tonne.
Coating and lining Cost of applying external coating and internal lining to the pipe. A spare allowance of 2.5% is included.	PE[121] coating $14.25/m^{2}. FBE coating $20.55/m^{2}. Concrete weight coat $1,020/tonne.	No lining was assumed. FBE coating applied to main and loopline only, PE elsewhere. Concrete over PE on main Gulf and estuary crossings.
CP and pipeline instrumentation installation Supply of instrumentation separately provided for under SCADA and E&I (see	$856/km.	The amount obtained was included in this estimate in the total for pipeline construction.

120 Venton & Associates contribution to the Expert Opinion by Venton & Associates and Worley Limited, (submitted by Epic) and dated 19 March 2002.

121 PE is extruded polyethylene, FBE is fusion-bonded epoxy.

below).		
Owner supplied materials Items provided by owner for use or installation by others, such as signs, induction bends, minor items not included elsewhere.	1% of total pipe cost and pipeline construction cost.	
Valve stations Cost of valves and installation of stations.	Equated to cost of 500m of steel pipe and its installation.	Increased by 50% where pressure > 7,000kPa (Class 600 operation). In this instance the main line and Pt Pirie/Whaylla lateral only are affected.[122]
Scraper stations Cost of scrapers and installation of stations.	Equated to cost of 1,000m of steel pipe and its installation.	Increased by 50% where pressure > 7,000kPa (Class 600 operation) – in this instance the main line and Pt Pirie/Whaylla lateral are affected.
Land and easement Cost of land for purchase and easement.	\$3,000/km.	An additional allowance for native title costs of \$5,000/km is included in the estimate separately.
EPCM Engineering, procurement and construction management.	7% of total base cost (cost of all the preceding items).	This is also applied to meter station, compressor and SCADA and E&I cost (see below).
Overheads Includes head office, transport, legal, insurance costs etc.	6% of total base cost.	This is also applied to meter station, compressor and SCADA and E&I cost (see below).

Native title compensation

To provide for the uncertainty surrounding costs of the administration of native title matters, the Commission adopted the rate of \$5,000/km (of pipeline), as suggested in Epic’s original application.

Compressors

Epic’s Option B requires 23,000kW of total installed compressor power, whereas the Commission’s Option D requires 32,000kW total installed compressor power. The cost of this item is greater in the Commission’s estimate for this reason as well as a higher equivalent unit cost.

Epic’s compressor cost model was based on a unit cost that varied from \$2,000/kW for the largest unit station to \$5,000/kW for the smallest.

122 Regulation of pressure is assumed downstream of Wasleys.

The Commission's compressor-costing model determined the cost of supply and installation of compressor stations based on a (generally non-linear) function of the following:

- the unit size (in ISO rated power);
- a unit cost rate;
- a location factor similar to that used in adjusting the unit cost of pipeline construction;
- a fittings cost factor that increases with the maximum design pressure rating;
- a factor that increases when the ratio of outlet to inlet pressure across a station increases; and
- a factor that assumes that in multi unit stations, the cost of installation of the second and subsequent units is half that of the first unit.

The Commission's costing model described above is sensitive to changing site conditions and pipeline flow and pressure requirements. After converting the cost obtained to a unit rate expressed in the same terms as Epic's ($/kW) it produces a higher equivalent cost in this instance.[123]

Meter & regulator stations

In regard to meter and regulator stations, the Commission's estimate is higher than Epic's by approximately 20 percent.

Epic's model employed a unit rate of $20,000 regardless of size for small meter stations (the cut off point is confidential). Small industrial/commercial meter stations were costed at $20,000/TJ/day of maximum design capacity.

The Commission's meter (and regulating) station cost model used is similar to that for the compressor station and depends on location and fittings cost factors as described under the compressor station model above. The capacity of each station was as specified by Epic in its AAI submission.[124]

SCADA & Communications

This item is for provision of a SCADA system and communications system along the pipeline network.

Epic assumed a fixed sum of $7.7 million for this item but had included an amount of approximately $700,000 per annum for 'utilities' under O&M costs. This appears to be based on rental charges for a backbone communications system provided by others.

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[123] The 'unit rate' for the third compressor station in the Commission's results (at 'Compressor station 5') is lower for the same unit size as that for the other two stations in the Commission estimate. This is because of the greater number of installed units at the third site.

[124] Regulating station capacity is specified differently to that of meter stations in the Commission cost model.

The Commission's estimate of $3.3 million was for a SCADA system without such a backbone communications system and includes an allowance for telemetry equipment and instrumentation on the pipeline.[125]

Linepack

The difference between the two linepack estimates is caused solely by differences in linepack inventory in the pipeline systems (different operating pressures and main pipeline diameters). The Commission has used the cost of gas nominated by Epic.

Operations and maintenance facilities

Epic allowed separate lump sums for a maintenance depot, head office/gas control and for spares.

The Commission's total for these items is higher, due to estimating these costs as a percentage of the total base cost (before interest) of 2.2 percent for the first two items taken together and 1 percent for total spares.

Interest on capital

Epic has revised its determination of interest on capital during construction prior to commissioning of the pipeline system. This amount is commonly capitalised and is therefore part of the total capital cost of construction of the system. After commissioning of the system these costs are expensed.

Both the Commission's estimate and that of Epic generally assumed a linear expenditure pattern over an assumed construction period. They differ in the assumed effective interest rate and, in its recent revision, Epic has increased its estimated construction period from 18 to 24 months.

As at the time of the *Final Decision*, the main differences between the two estimates were as follows:

- the Commission assumed 100 percent debt funding at a rate of 6.68 percent over a construction period of 18 months;
- Epic assumed:
  - 90 percent debt funding at a rate of 7.0 percent
  - 10 percent equity funding to fund initial design;
  - 25 percent of expenditure initially to purchase materials; and
  - balance in equal draw downs over 18 months.

In its recent revision, Epic has assumed the following:

- a 24 month construction period;

[125] Meter station instrumentation is assumed to be included under the item for Meter and regulator stations.

- an amount (0.51 percent) for up front costs;
- 60:40 debt/equity;
- debt funding at 7.2 percent; and
- equity funding of 15 percent.[126]

After taking into account the difference in costs before interest is added, Epic's estimate is higher than the Commission's mainly because of a longer assumed construction period and a higher cost of funds.

Epic provided no justification for its shift to the assumption of a construction period of 24 months in its latest lodgement. A construction period of 18 months, as originally proposed by Epic, is achievable provided efficient project management is employed.

In its previous ORC assessments, the Commission has based the required rate of return on 100 percent debt funding, at a rate of 6.68 percent for the MAPS *Final Decision*. The Commission has reconsidered its position on this issue. While in practice 100 percent debt finance during construction is not uncommon, the Commission has decided to use its calculation of the nominal vanilla WACC as the required rate of return, which assumes a 60/40 debt to equity ratio. This approach is consistent with the Commission overall assumption of a stand-alone pipeline service provider as the regulated entity, and was also supported by Davis and Handley in a recent report prepared for the Commission.[127]

The Commission's use of the nominal vanilla WACC in calculating interest during construction has increased this ORC element from $29.8 million to $36.9 million. However, the Commission's calculation is still substantially less than Epic's calculation of $57 million. This can be attributed to the shorter construction period and lower calculation of the costs of debt and equity that feed into the calculation of WACC.

Adjustment for CPI and exchange rates

In its original AAI, Epic submitted estimates in 31 December 1998 dollars and stated that the exchange rate assumed was $0.65US/$A. Epic has not changed these assumptions in the revised AAI.

In deriving the revised Table 2.3 above, Epic's values were adjusted to 30 June 2001 dollars using a simple CPI factor conversion. This resulted in an increase of approximately 9.8 percent.[128]

This method provides a relatively straightforward means of updating for changing money values, and is employed in a similar way in the revenue model used in calculating regulated revenues each year. This method is therefore the most appropriate to employ in this context.

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126 Epic used the average of its low and high cost of equity assumptions (13.08% and 16.84% respectively).

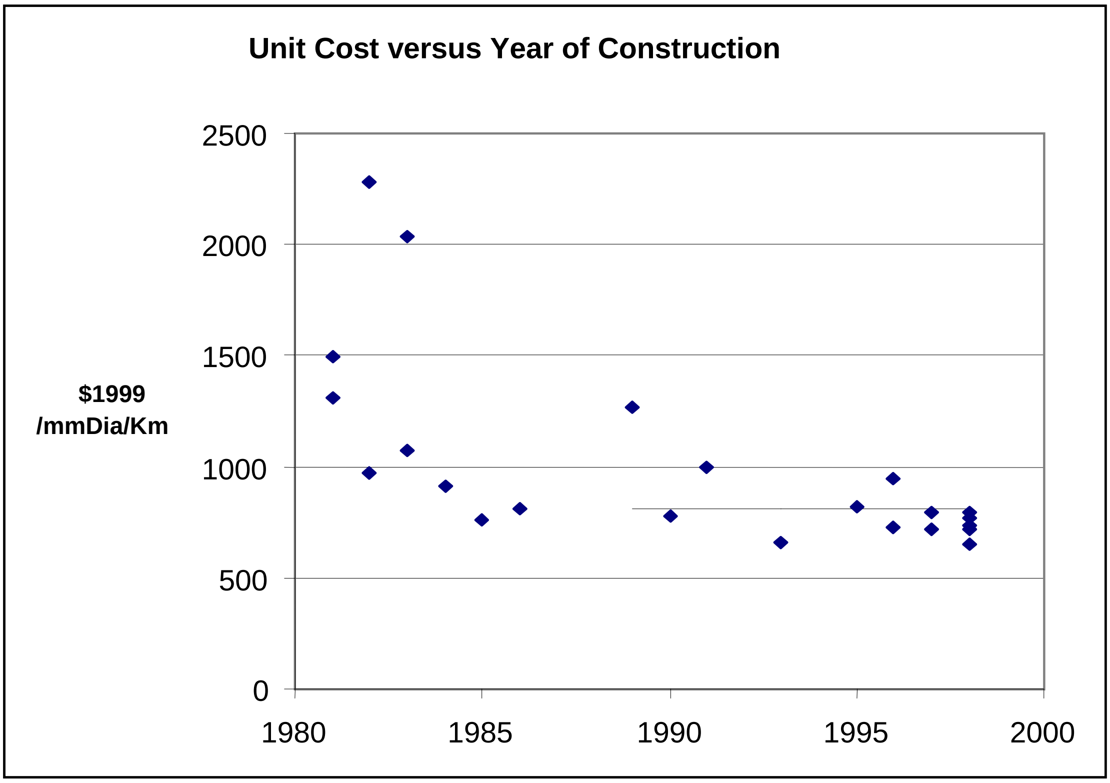
127 Kevin Davis and John Handley, *A report on Cost of Capital for Greenfields Investments in Pipelines*, April 2002, page 21.

128 The CPI (weighted average 8 cities) was 121.9 at end-December 1998; 133.8 at end-June 2001. No accounting for the GST effect over this period has been made.

The Commission’s estimate derived a $A per tonne cost of pipe based on the $A/$US exchange rate prevailing at 30 June 2001 of $US0.51/$A. (Prices for line-pipe in the MicroAlloying report were quoted in $US on the basis of an exchange rate of $US0.55/$A.) Elsewhere, where appropriate, individual unit rates were adjusted either for CPI or exchange rate, but not both.

However, there is no evidence to suggest that real pipeline industry costs in Australia have increased in recent years, in spite of adverse exchange rates over the period. In fact, as the accompanying graph of pipeline real unit costs indicates, it could be concluded that pipeline costs have remained constant in real terms over the last twenty years and any further adjustment for exchange rate changes during this period is not appropriate.

Pipeline unit cost versus year of construction[129]



Source: GPU Gasnet Pty Ltd Application for revision to Access Arrangement South West pipeline August 1999.

6. Conclusion

Based on the preceding discussion it can be concluded that the determination of ORC adopted by the Commission is appropriate and fair, for reasons summarised below.

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129 GPU Gasnet excluded data for pipelines costing in excess of $3000/km.mm and pipe sizes less than or equal to 150mm diameter. Data were taken from Philip Venton’s paper to the APIA International Convention 1998 and converted from 1995 to 1999 values using CPI.

- Unit rate comparisons show the Commission's estimate is consistent with other Commission determinations.
- A rate equivalent to that rate proposed by Epic for pipeline construction was used. This item accounts for approximately 30 percent of capital cost before interest.
- A rate per tonne for pipe representative of current market conditions was used. Estimated costs for coating and delivery of pipe were added. These items in total also account for approximately 30 percent of capital cost before interest. (Epic did not separately identify pipe costs.)
- Costs for compressor, meter and regulating stations exceeded those submitted by Epic both in total and after comparing equivalent unit rates. These items account for approximately 19 percent of capital cost before interest.
- Costs for EPCM and overheads were estimated separately. These items account for approximately 11 percent of capital cost before interest.[130]
- Costs of valve and scraper stations, owner supplied materials, land and easement were determined separately. These items account for approximately 5 percent of capital cost before interest.
- Cost estimates for operations & maintenance facilities are higher than those Epic assumed. These items account for approximately 3 percent of capital cost before interest.
- The allowance for native title costs was the same as assumed by Epic. This item accounts for approximately 1 percent of capital cost before interest.
- Estimates for SCADA and linepack are less than Epic's. These items account for less than 1 percent of capital cost before interest.
- Sufficient allowance for omissions is built into the various rates and costing models employed in deriving the estimate. No further contingency allowance is considered appropriate.
- Appropriate allowances for CPI and exchange rate have been made.
- The amount for interest on capital during construction has been changed by adopting the debt/equity mix proposed by Epic but employing the *Final Decision* WACC of 9.1 percent and retaining a construction period of 18 months.

With the latter adjustment, the ORC for the pipeline of $632 million.

[130] Or 13% of capital costs before linepack, operations & maintenance facilities and interest.