OFFICE OF GAS ACCESS REGULATION

OffGAR WESTERN AUSTRALIA

Final Decision on the Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline

Submitted by

EPIC ENERGY (WA) TRANSMISSION PTY LTD

Independent Gas Pipelines Access Regulator
Western Australia

23 May 2003

CONTENTS

DECISION 3

REASONS 3

- Introduction 3
- Access Arrangement Documents 5
- Requirements of the Code 6
- Services Policy 7
- Reference Tariff and Reference Tariff Policy 20
  - Requirements of the Code 20
  - Form of Regulation and Variation of the Reference Tariff 23
  - Initial Capital Base 24
  - New Facilities Investment 67
  - Rate of Return 72
  - Depreciation 79
  - Non Capital Costs 83
  - Total Revenue 86
  - Cost/Revenue Allocation and the Reference Tariff 89
  - Incentive Mechanisms 114
  - Conclusions 117
- Terms and Conditions 124
- Capacity Management Policy 145
- Trading Policy 146
- Queuing Policy 149
- Extensions/Expansions Policy 152
- Review and Expiry of the Access Arrangement 155
- Other Matters Addressed by the Proposed Access Arrangement 157

AMENDMENTS 159

- Services Policy 159
- Reference Tariff and Reference Tariff Policy 160
- Terms and Conditions 161
- Trading Policy 164
- Queuing Policy 164
- Extensions/Expansions Policy 165
- Review and Expiry of the Access Arrangement 165

DECISION

1. On 21 June 2001 I issued my Draft Decision[1] on the proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline ("**DBNGP**"). My Draft Decision was to not approve the Access Arrangement and I indicated 79 amendments to the proposed Access Arrangement that would have to be made before the proposed Access Arrangement would be approved.

2. I am required under section 2.16(a) of the *National Third Party Access Code for Natural Gas Pipeline Systems* ("**Code**") to issue a Final Decision that either approves the Access Arrangement originally proposed by Epic Energy; or does not approve the Access Arrangement originally proposed and states the amendments (or nature of amendments) which would have to be made to the Access Arrangement in order for me to approve it.

3. I have considered the proposed Access Arrangement under the principles set out in the Code. In summary, I have considered and weighed the factors in section 2.24 of the Code as fundamental elements in making the overall decision whether to approve the proposed Access Arrangement, recognising that at some points the Code expresses the section 2.24 factors in specific provisions dealing with particular aspects of the Access Arrangement.

4. My Final Decision is to not approve the proposed Access Arrangement on the basis that it does not satisfy the principles in sections 3.1 to 3.20 of the Code. The detailed reasons for my decision are set out in this document.

5. I am also required by section 2.16 of the Code to state the date by which a revised Access Arrangement must be submitted to me. In accordance with section 2.16, Epic Energy must submit a revised Access Arrangement to me by 4 pm on 4 July 2003.

REASONS

Introduction

6. On 15 December 1999, Epic Energy (WA) Transmission Pty Ltd ("**Epic Energy**") submitted a proposed Access Arrangement for the DBNGP to me as the Western Australian Independent Gas Pipelines Access Regulator ("**Regulator**") for approval under the Code.

7. The DBNGP comprises a gas transmission system consisting of a main pipeline from Dampier in the north west of Western Australia to Bunbury in the south west of Western Australia and associated compressor facilities, mainline valves, lateral pipelines, delivery stations, metering stations, operating and communication facilities and odorising facilities.

[1] Capitalised terms used in this document are defined terms with definitions provided either in this document, in the Code, or in Epic Energy's Access Arrangement documents.

8. I have assessed the proposed Access Arrangement against the requirements and principles of the *Gas Pipelines Access (Western Australia) Act 1998* (**"GPAA"**), which gives effect to the *Gas Pipelines Access (Western Australia) Law*, which includes the Code. As part of this assessment, I considered the issues raised in submissions made on the proposed Access Arrangement by interested parties and I issued a Draft Decision on 21 June 2001.

9. My Draft Decision was to not approve the proposed Access Arrangement in its submitted form. The reasons for this decision were stated in the Draft Decision in its Parts A and B.

10. Subsequent to issue of the Draft Decision, Epic Energy commenced proceedings in the Supreme Court of Western Australia seeking certain declarations and prerogative relief regarding the proper construction of the Code and my application thereof in the Draft Decision. On 23 August 2002, the Full Court of the Supreme Court handed down its decision on Epic Energy's proceedings ("**Court Decision**"), a copy of which may be accessed from the website of the Office of Gas Access Regulation (www.offgar.wa.gov.au).

11. On 2 September 2002, I issued an information paper informing interested parties of the procedure that I proposed to follow in light of the Court Decision for the preparation of this Final Decision on Epic Energy's proposed Access Arrangement. The Court proceeded, in part, on the basis that, following the Court Decision, I would allow all interested parties a reasonable time to prepare and provide submissions to me which have regard to the reasons of the Court Decision and the effects of these reasons on the matters identified in the Draft Decision as being the reasons for requiring amendments to the proposed Access Arrangement.

12. The process applied by me has been the following:

- interested parties were invited to prepare and provide written submissions having regard to the reasons in the Court Decision and the effects of these reasons on matters identified in the Draft Decision as being the reasons for requiring amendments to the proposed Access Arrangement;

- those submissions which were not of a confidential or commercially sensitive nature were made publicly available on the O*ff*GAR website;

- parties making submissions were invited to also indicate whether they wished to speak to those submissions at a conference with me: conferences were held with Epic Energy, WMC Resources, Wesfarmers CSBP, AlintaGas, Chevron Texaco, Western Power, North West Shelf Gas, Mr Nick Catania, Deutsche Bank and AMP Henderson; and

- notices were issued under section 41 of schedule 1 to the GPAA to certain parties to obtain further information in light of the reasons identified in the Court Decision.

13. The Court Decision did not deal with the final declarations the Court would make. Those declarations were handed down separately on 20 December 2002. For ease of reference, the declarations are reproduced as follows.

1. The determinations of Reference Tariffs and of the initial Capital Base of the Dampier to Bunbury natural gas pipeline ("Pipeline") made by the Independent Gas Pipelines Access Regulator ("Regulator") in his draft decision ("Draft Decision ") issued on 21 June 2001 are affected by errors of law and require reconsideration by the Regulator according to law.

2. The factors in s 2.24(a) to (g) of the *National Third Party Access Code for Natural Gas Pipeline* Systems ("Code"), as applied in Western Australia by s 9 of the *Gas Pipelines Access (Western Australia) Act 1998* ("Act"), are relevant to, and are to be given weight as fundamental elements in, the Regulator's assessment of the proposed Access Arrangement, including the issue whether the Regulator is satisfied that the proposed Access Arrangement contains the elements and satisfies the principles set out in s 3.1 to s 3.20.

3. The factors in s 2.24(a) to (g) should guide the Regulator in determining, if necessary, the manner in which the objectives in s 8.1(a) to (f) can best be reconciled or which of them should prevail.

4. The factors in s 8.10(a) to (k) are relevant to, and are to be given weight as fundamental elements in, the establishment of the initial Capital Base of the pipeline.

5. It is open to the Regulator, pursuant to the objective provided by s 8.1(d), to take into account the actual investment of the first applicant in the pipeline when designing a Reference Tariff and a Reference Tariff Policy, including in that context the establishment of the initial Capital Base of the pipeline.

6. The purchase of the pipeline by the first applicant on 25 March 1998, the circumstances of that purchase including the price paid, and any value according to a recognised asset valuation methodology which may be revealed by the price paid in those circumstances, are matters which the Regulator may properly take into account in determining, for the purposes of s 8.11, whether the initial Capital Base for the pipeline should fall outside the range of values determined under s 8.10(a) and (b).

7. For the purposes of s 8.10 and s 8.11, and in particular s 8.10(c), (d) and (j), it is not the meaning and effect of the Code that only "efficient" capital investment, or that only "regulated revenues", are to be taken into account; nor that the initial Capital Base should represent a value "that is consistent with future regulated revenues and efficient capital investment".

Access Arrangement Documents

14. Epic Energy submitted its proposed Access Arrangement documentation on 15 December 1999. This documentation comprised the proposed Access Arrangement, Access Arrangement Information, and Access Contract Terms and Conditions. Additional supporting documents were subsequently provided to me, and a revised Access Arrangement Information was submitted on 28 July 2000. The final set of documents received by me and subject to assessment was as follows.

- *Proposed Access Arrangement under the National Access Code* (15 December 1999), incorporating a *Tariff Schedule* (Annexure A) and *Proposed Access Contract Terms and Conditions under the National Access Code* (Annexure B).

- *Proposed Access Arrangement Information under the National Access Code* (28 July 2000), incorporating *Proposed DBNGP System: Description of the Gas Transmission System as at 1 January 2000* (Appendix 1); *Brattle Group Report on Cost of Capital* (Appendix 2); *DBNGP Maps* (Appendix 3); and *Brattle Group Report on Regulatory Model for the DBNGP* (Appendix 4).

- *Proposed Access Guide under the National Access Code* (15 December 1999).

- *Proposed Secondary Market Rules under the National Access Code* (15 December 1999).

- *Proposed Secondary Market Terms and Conditions under the National Access Code* (15 December 1999).

15. Copies of these documents are available from the Office of Gas Access Regulation or may be downloaded from the O*ff*GAR web site (www.offgar.wa.gov.au).

16. Of these documents, Epic Energy has informed me that the Proposed Access Guide is intended by Epic Energy to meet the requirements under section 5.1 of the Code for a Service Provider to establish and maintain an Information Package. I consider that the Proposed Access Guide does not constitute part of the proposed Access Arrangement that is the subject of this Final Decision. While section 5.2 of the Code provides for the Relevant Regulator to require the Service Provider to amend or include additional information in the Information Package under certain circumstances, I envisage that any related assessment of the Information Package would be undertaken as a separate exercise to the process of approval of the proposed Access Arrangement. I have nevertheless referred to the Proposed Access Guide to assist me in understanding the proposed Access Arrangement.

Requirements of the Code

17. Section 2.24 of the Code provides that:

> 2.24 The Relevant Regulator may approve a proposed Access Arrangement only if it is satisfied the proposed Access Arrangement contains the elements and satisfies the principles set out in sections 3.1 to 3.20. The Relevant Regulator must not refuse to approve a proposed Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that sections 3.1 to 3.20 do not require an Access Arrangement to address. In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:
>
> (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 economically efficient operation of the Covered Pipeline;
>
> (e) the public interest, including the public interest in having competition in markets (whether or not in Australia);
>
> (f) the interests of Users and Prospective Users;
>
> (g) any other matters that the Relevant Regulator considers are relevant.

18. The "elements" of a proposed Access Arrangement, referred to in section 2.24 of the Code comprise:

- Services Policy (sections 3.1 and 3.2 of the Code);

- Reference Tariff and Reference Tariff Policy (sections 3.3 to 3.5 of the Code);

- Terms and Conditions (section 3.6 of the Code);
- Capacity Management Policy (sections 3.7 and 3.8 of the Code);
- Trading Policy (sections 3.9 to 3.11 of the Code);
- Queuing Policy (sections 3.12 to 3.15 of the Code);
- Extensions/Expansions Policy (section 3.16 of the Code);
- Review Date (sections 3.17 to 3.20 of the Code).

19. As noted by the Court,[2] it is clear from the Code and the nature of an Access Arrangement that an Access Arrangement may deal with a number of matters beside those dealt with in sections 3.1 to 3.20, but an Access Arrangement must contain at least the elements dealt with in sections 3.1 to 3.20 and satisfy the principles set out in those sections.

20. I now proceed to an examination of the elements of the proposed Access Arrangement.

Services Policy

21. Section 3.1 of the Code requires that an Access Arrangement include a policy on the Service or Services to be offered (a Services Policy). Section 3.2 of the Code requires that the Services Policy comply with the following principles.

> (a) The Access Arrangement must include a description of one or more Services that the Service Provider will make available to Users or Prospective Users, including:
>
> (i) one or more Services that are likely to be sought by a significant part of the market; and
>
> (ii) any Service or Services which in the Relevant Regulator's opinion should be included in the Services Policy.
>
> (b) To the extent practicable and reasonable, a User or Prospective User must be able to obtain a Service which includes only those elements that the User or Prospective User wishes to be included in the Service.
>
> (c) To the extent practicable and reasonable, a Service Provider must provide a separate Tariff for an element of a Service if this is requested by a User or Prospective User.

22. Therefore, the Access Arrangement must specify the services that the service provider will make available. The Service Provider is not obliged to provide a service unless it is one of the services specified in the Access Arrangement (or an element of such a service).

23. A Services Policy is provided in section 6 of the proposed Access Arrangement.

24. Epic Energy has elected in its Services Policy to distinguish between a Reference Service and a range of Non-Reference Services.

[2] [2002] WASCA 231, paragraph 41

25. A Reference Service is a service that is specified in an Access Arrangement and for which a Reference Tariff is specified in that Access Arrangement under section 3.3 of the Code:

> An Access Arrangement must include a Reference Tariff for:
>
> (a) at least one service that is likely to be sought by a significant part of the market;
>
> (b) each Service that is likely to be sought by a significant part of the market and for which the Relevant Regulator considers a Reference Tariff should be included.

26. Only those services likely to be sought by a significant part of the market, and for which I consider there should be a price, need to have a Reference Tariff specified. For other services, section 6 of the Code provides a process of negotiation and arbitration for determining the price.

27. For the reason that Epic Energy has distinguished between Reference and Non-Reference Services in the Services Policy, the designation of Reference Services is addressed in this section of my Decision, rather than in relation to the Reference Tariff and Reference Tariff Policy. I have therefore assessed the Services Policy under sections 3.1, 3.2 and 3.3 of the Code, guided by the factors set out in section 2.24.

28. The Services Policy commits Epic Energy to making available a single service (the "**Firm Service**") to Prospective Users as a Reference Service.

29. The Services Policy also indicates that Epic Energy is prepared to negotiate (subject to operational availability) on provision of other services or elements of services sought by a Prospective User and for which a Reference Tariff is not specified in the Access Arrangement ("**Non-Reference Services**"). In sub-section 6.1 of the Access Arrangement, Epic Energy has stated that a non-exhaustive list of Non-Reference Services which Epic Energy might be prepared to negotiate is as follows.

- Secondary Market Service, comprising a trading system to be operated by Epic Energy for trading Firm Service capacity on a daily 'spot' basis. Epic Energy has proposed "Secondary Market Rules" and "Secondary Market Terms and Conditions" for this system, which were submitted to me as part of the proposed Access Arrangement documentation.

- Park and Loan Service, proposed as a negotiated, interruptible Non-Reference Service to allow Users to remedy imbalances (between capacity shipped and delivered) in excess of the Firm Service imbalance limits.

- Seasonal Service, proposed to comprise capacity made available by Epic Energy out of capacity over and above Firm Service capacity that becomes available due to seasonal factors. The Seasonal Service is proposed as a negotiated Non-Reference Service to allow Shippers to contract additional capacity for particular months of the year to supplement their contracted Firm Service capacity.

- Peaking Service, proposed to cater for hourly-capacity demands at a Delivery Point in excess of 120 percent of Maximum Hourly Quantity ("**MHQ**", equal to one twenty-fourth of the Delivery Point Maximum Daily Quantity – "**MDQ**").

- Metering Information Service.
- Pressure and Temperature Control Service.
- Odorisation Service.
- Co-mingling Service.

30. Additional descriptive information on some of these services is provided in the Proposed Access Guide. However, no descriptive information is provided in the proposed Access Arrangement or associated documents on the Metering Information Service, the Pressure and Temperature Control Service, the Odorisation Service or the Co-mingling Service.

31. Non-Reference Services are also defined to include services provided by Epic Energy under contracts entered into prior to commencement of the Access Arrangement Period ("the Contract Services").

32. In assessing the proposed Services Policy, I am required to consider the services that a significant part of the market is likely to seek. One or more such services must be included in the Access Arrangement and must be described. If I form the opinion that other services should also be included then they must also be included and described. Of these services only one that is sought by a significant part of the market need be specified as the Reference Service, although I must consider whether any of the other services that are likely to be sought by a significant part of the market should also be included as a Reference Service.

33. Because the Access Arrangement proposes the Firm Service as the only service (and the only Reference Service) I need to consider:

    - whether the Firm Service is a service likely to be sought by a significant part of the market;
    - whether there are other services that should be described in the Access Arrangement; and
    - if so, whether any of those services should be included as a Reference Service.

34. The Firm Service has the following general characteristics.

    - Epic Energy has divided the pipeline into 11 zones, referred to as Zones 1 to 4, 4a and 5 to 10. The Firm Service is a service under which gas may be received into the pipeline at a Receipt Point in Zone 1 and delivered to a Delivery Point in any zone.
    - The Firm Service can involve either forward-haul or back-haul of gas.
    - The service is not subject to interruption or curtailment except as permitted by the Access Contract.
    - The minimum contract term is five years unless otherwise agreed to by Epic Energy in Epic Energy's sole discretion.

35. With respect to the Firm Service, Users have submitted to me that no significant part of the market for gas transportation in the DBNGP is likely to seek a service in the form, and on the terms and conditions, proposed for the Firm Service and that, therefore, the Firm Service does not satisfy the requirement of the Code that the Service Provider offer a standard service that is likely to be sought by a significant part of the market.

36. In assessing whether a service is likely to be sought by a significant part of the market, it is not necessary for me to consider whether there is significant demand for the precise terms and conditions proposed for the Firm Service, that being a matter for consideration under section 3.6 of the Code. However, I am required to determine whether the nature of the service (or product) described in the Access Arrangement, considered in the context of the range of services that might be provided using the pipeline, identifies a service (or product) that is likely to be sought by a significant part of the market.

37. I am satisfied that the Firm Service is a service that is likely to be sought by a significant part of the market (and therefore appropriate to be specified as the Reference Service). I note that several Users have submitted that the existing regulated service, the T1 Service, should also be included in the Services Policy as a Reference Service. This is addressed further below.

38. In regard to the provision for back-haul of gas as part of the Firm Service, I indicated in my Draft Decision that a limitation on the back-haul of gas arising from Epic Energy's ability to restrict upstream deliveries appeared not to be reasonable.[3] Clause 6.3 of the Access Arrangement states that:

> If the Shipper's Delivery Point is upstream of the Shipper's Receipt Point ("Upstream Deliveries") and on a Day, the total quantity of gas transported for all shippers with a Delivery Point downstream of their Receipt Point is insufficient to maintain Upstream Deliveries without the need to change the normal direction of gas flow in the DBNGP, Epic Energy may restrict Upstream Deliveries in its absolute discretion without liability to the Shipper.

39. In making my Draft Decision, I was concerned that the provisions for Epic Energy to interrupt a back-haul service in the event of a shortage of gas received into the pipeline would allow Epic Energy to unreasonably gain financial advantage by preferentially maintaining services to Users utilising forward-haul services that return greater revenues to Epic Energy. On further consideration of this matter, I am satisfied that the limitation that Epic Energy has placed on the back-haul of gas under the Firm Service serves to maintain the operational integrity of the pipeline and will not prejudice the interests of Users or Prospective Users.

40. In relation to other services, Epic Energy has not committed to making available any of the listed Non-Reference Services mentioned in its proposed Access Arrangement. Rather, it has indicated it "might" be prepared to negotiate (subject to operational availability) on provision of the services listed. This is contrary to the requirements of section 3.2 of the Code, which require that the Services Policy "must include a description of one or more Services that the services policy *will* make available to

[3] Draft Decision, Part B p 39.

users or Prospective Users" (emphasis added). Therefore, they are not services under the proposed Services Policy.

41. In the absence of any other services specified in the proposed Access Arrangement as being available, I have therefore considered whether there are any other services that should, in my opinion, be included in the Services Policy, either as part of or in addition to the Firm Service, having regard to paragraphs 3.2(b) and (c) of the Code.

42. A characteristic of the proposed Firm Service is that, under this service, receipt of gas into the pipeline is restricted to locations in Zone 1 of the pipeline. Receipt of gas into the pipeline at a location in any other zone of the pipeline would need to be negotiated with Epic Energy.

43. There are gas-exploration and development activities occurring in Western Australia that could lead to a demand for receipt of gas into the DBNGP at locations outside of Zone 1, such as gas delivered to the DBNGP from gas fields in the Perth Basin and the South West of the State. In respect of gas transmission from gas producers in the Perth Basin, the prospect for transmission of such gas via the DBNGP was a factor considered by the Western Australian Minister for Energy in his decision to revoke coverage of the Parmelia Pipeline under the GPAA.[4]

44. Epic Energy has also proposed a minimum five-year term for contracts for the Firm Service. Submissions made to me have indicated that this minimum contract term may be unreasonably long. The proposed minimum contract term is substantially in excess of minimum contract terms of one or two years established under Access Arrangements for other transmission pipelines and distribution systems in Australia, generally at the initiative of the Service Providers. It is also in excess of the minimum contract term for Epic Energy's Moomba to Adelaide Pipeline.

45. Epic Energy justifies the minimum contract term on the basis that it is necessary to provide contractual security to Epic Energy in providing access contracts for pipeline capacity that is provided through expansions to the pipeline, with the associated investment from Epic Energy. I am of the view that a shorter minimum term for the Firm Service than the five years proposed by Epic Energy does not oblige Epic Energy to expand the capacity of the pipeline to meet the requirements of short-term capacity contracts.

46. I am also of the view that with the introduction of full retail contestability in gas markets in Western Australia and with proposed deregulation of electricity markets, that there are likely to be new customers coming into the market for gas transmission services. To the extent that long minimum terms for gas transmission contracts may impose a barrier to entry to gas and electricity markets, I consider that a minimum contract term of two years would be in the public interest, including the public interest in having competition in markets.

[4] Hon. Eric Ripper, Minister for Energy, 13 March 2002, Decision on coverage in relation to the application to the National Competition Council requesting that coverage of Parmelia Pipeline (PL1–3,5 and PL23) be revoked, p4.

47. There is currently no provision in either the proposed Access Arrangement or Access Contract Terms and Conditions for metering information to be provided to Users as part of the Firm Service. The Access Contract Terms and Conditions would impose a range of penalties on Users in certain circumstances including a nomination surcharge (paragraph 4.4(c)), overrun charge (sub-clause 5.2) and excess imbalance charge (sub-clause 6.4). If a User of the Firm Service is potentially liable for these penalty charges, then it is contrary to the reasonable interests of Users that they should not have access to the necessary metering information to enable them to assess and minimise their potential liability. I consider that such metering information should be provided where it is reasonable and practicable for Epic Energy to provide the information.

48. Accordingly, I am of the view that the Access Arrangement should include a Reference Service with the characteristics of the Firm Service, but which allows for receipt of gas at locations outside of Zone 1 of the pipeline, minimum contract terms of two years and metering information; reflecting an appropriate balance of interests under section 2.24 of the Code.

49. Several submissions to me proposed that the Access Arrangement should include a range of component services which were previously available as part of the "T1 Service" established under the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998*. These submissions partly related to the desire of Users for the proposed Firm Service to more closely resemble the T1 Service to facilitate the transition of existing contracts to a transmission tariff determined under the Code but the submissions also identified demand for the facilities offered by the additional service components themselves.

50. The T1 Service as defined under the Gas Transmission Regulations 1994 and Dampier to Bunbury Pipeline Regulations 1998 comprises a "bundle" of services including:

- a basic gas transmission service;
- a "Seasonal Service", providing for Users to contract for higher levels of MDQ for only a part of the year;
- an "authorised overrun service", providing for Users to take delivery of gas in excess of contracted MDQ; and
- a "spot service" providing for Users with a contract for the T1 Service to purchase and contract for pipeline capacity (defined in terms of MDQ) on a short-term basis.

51. Several submissions made to me in regard to the proposed Services Policy, principally by existing Users, highlighted differences between the proposed Firm Service and the existing T1 Service. Several submissions indicated that while both the T1 Service and the Firm Service comprise, in general terms, "non-interruptible" (firm) haulage services, the two services differ in both the scope of the "bundle" of services provided under the title of the regulated service, and in the terms and conditions on which each service is provided. The submissions indicated the following characteristics of the Firm Service to be more restrictive than the T1 Service.

- Reduced opportunity for a User to relocate contracted capacity between Delivery Points.
- More restrictive peaking limits and higher penalties for exceeding peaking limits.
- More restrictive imbalance limits and higher penalties for imbalances.
- Reduced opportunity for changing daily nominations, and provision for penalties on variance of actual gas deliveries from nominations.
- Reduced opportunity for trading of capacity between Users.
- A different tariff structure with a zone-based rather than distance-based tariff, a different division of the total tariff between the fixed capacity charge and the variable throughput charge, and introduction of new charge components.
- Provision of seasonal adjustments to contracted MDQ as a Non-Reference Service rather than as part of the regulated service.
- Provision of a Park and Loan Service as a Non-Reference Service rather than as part of the Reference Service.

52. It was further proposed in submissions from Users that the Reference Service established by the Access Arrangement should not be materially different from the T1 Service. Several reasons were put forward in submissions in support of this proposition, as follows.

- The T1 Service was developed by an extensive consultation process that:
  - resulted in a definition of a regulated service that meets the requirements of the majority of Users of the DBNGP;
  - reflected the operational characteristics of the DBNGP; and
  - achieved a reasonable balance of interests between the Service Provider and Users in the terms and conditions on which the service is provided and in the allocation of risk between the Service Provider and Users.
- The T1 Service is a bundled set of services required by a significant part of the market.
- The Firm Service provides an inappropriate benchmark for the Western Australian Gas Disputes Arbitrator to arbitrate on disputes in regard to provision of a service. Under Section 6.13 and section 6.18(e) of the Code the “Reference Service” and the “Reference Tariff” are benchmarks that guide the Arbitrator in deciding what service a Service Provider must offer to a Prospective User, and on what terms and conditions that service will be provided. A Reference Service that favours the interests of the Service Provider has the effect of disadvantaging Prospective Users that choose to negotiate or seek arbitration in relation to access, because the Arbitrator will use the Reference Service as a benchmark.

- Epic Energy is legally obliged under the GPAA to include in its Access Arrangement a Reference Service materially the same as a T1 Service under the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998,* and to set a Reference Tariff for that service.

- In schedule 39 of the Asset Sale Agreement by which AlintaGas sold the DBNGP to Epic Energy, Epic Energy made representations to AlintaGas that a Reference Service equivalent to the T1 Service would be included in the Access Arrangement.

53. In a further submission made to me subsequent to my Draft Decision, existing Users of the DBNGP stressed that the requirement for a T1-Equivalent Reference Service is derived from a requirement to have a Reference Tariff under the Access Arrangement recognised as the statutory price for the purposes of section 20 of the *Dampier to Bunbury Pipeline Act 1997* and for this statutory price to pass through to parties with existing contracts for gas transmission with a minimum of procedural requirements and associated cost. Existing Users contend that provision in the Access Arrangement for a T1-Equivalent Reference Service would be consistent with:

- the intent of the Western Australian Government in the sale of the DBNGP;

- the intent and requirements of section 20 of the Dampier to Bunbury Pipeline Act 1997;

- the interests of Users through providing contractual certainty and reducing costs of the pass-through of an Access Arrangement tariff to existing contracts; and

- providing a Reference Service that meets demand from a significant part of the market, albeit this being a "current" rather than "future" demand, and a demand arising principally from a desire to minimise costs of achieving a pass-through of the Access Arrangement tariff to existing Users, rather than being a demand for particular characteristics of the service.

54. Epic Energy has submitted that it is under no statutory or contractual obligation to provide a Reference Service that is equivalent to the T1 Service and that to impose such a requirement would be contrary to the intent of the Code in allowing a Service Provider to have discretion as to the terms and conditions and tariffs for services, subject to meeting the requirements of the Code.

55. By way of background, under section 20 of the Dampier to Bunbury Pipeline Act 1997, Epic Energy is obliged to offer to Users under existing contracts a maximum price not exceeding the "statutory price" applicable from time to time for their contracted service. The "statutory price" is the price the person could insist on paying if the person were entering into that contract at the present time. A statutory price is currently established by regulation 35 of the *Dampier to Bunbury Pipeline Regulations 1998* and applies to contracts for gas transmission entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998*.

56. Section 96 of the GPAA is also relevant. It makes it clear that section 20 of the *Dampier to Bunbury Pipeline Act 1997* will continue to operate in respect of existing

access contracts despite the approval of any proposed Access Arrangement or the operation of the Code.

57. It was submitted to me by several Users that in order for section 96 to be given full effect, the Access Arrangement must specify a tariff that qualifies as the "statutory price". This, it appears, would be achieved by specifying a Reference Service (and therefore a Reference Tariff) that is materially the same as or equivalent to the T1 Service. According to submissions, Users under existing contracts could then take advantage of section 20 and insist on paying the Reference Tariff for this Reference Service under the Code.

58. While I have considered these submissions, and it appears to me that establishing a Reference Service that is materially the same as or equivalent to the existing T1 Service would facilitate the smooth transition from the previous access regime to that under the Code, I do not have jurisdiction under either the GPAA or the *Dampier to Bunbury Pipeline Act 1997* to determine a statutory price for the purpose of section 20. It would have been a simple matter for the GPAA to provide that the Regulator must determine a price for the T1 Service. However section 96 does no more than provide that the operation of section 20 is not affected. The only issues I am concerned with in this regard are those arising under section 3.2(a) to (c) of the Code, taking into account section 2.24 of the Code. Those issues are whether or not there is a service likely to be sought by a significant part of the market and whether or not I consider that any other service should be included.

59. In this regard, although the demand for a T1-equivalent service is principally a demand from customers with existing contracts concerned about the pass-through under section 20 of the *Dampier to Bunbury Pipeline Act 1997* of a Reference Tariff to existing contracts for gas transmission entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998*, I am satisfied that the T1 service is a service likely to be sought by a significant part of the market for services provided by means of the DBNGP from the Service Provider, which includes that part of the market consisting of existing contractual arrangements.

60. Submissions from existing Users have also suggested that there is a significant demand for the ancillary services provided to date as part of the T1 Service. Epic Energy's proposed Firm Service comprises only a forward-haul and limited back-haul transmission service. The Firm Service proposed by Epic Energy does not include provision for seasonal differences in contracted capacity, an authorised overrun service or a spot service, as are included in the T1 Service.

61. Epic Energy has submitted that the services offered as part of the T1 Service are accommodated either as part of the Firm Service or by other means in no less advantageous way to Users, namely through the Secondary Market Service, the Seasonal Service and the Park and Loan Service.

62. In this regard, Epic Energy has proposed that it is prepared to negotiate with respect to a Seasonal Service as a Non-Reference Service, which provides for Users to contract for additional firm capacity on a seasonal basis. Epic Energy has also indicated it is prepared to negotiate on a Secondary Market Service as a Non-Reference Service that provides for Users to purchase firm capacity either from Epic Energy or from other Users on a daily basis. Similar to the authorised-overrun service and the spot service,

Users can, through the Secondary Market Service, take delivery of gas in excess of contracted MDQ on a short-term basis or increase contracted capacity on a short-term basis. As with the T1 Service, charges for these services, when provided through the Secondary Market Service, would be additional to charges for the core haulage service.

63. I have considered the submissions I received from Users and Epic Energy as summarised above and the proposed Access Arrangement itself, taking into account the factors in section 2.24 of the Code. Despite the differences identified above between the T1 Service and the Firm Service, provided that Epic Energy's Services Policy describes the services offered, this will make available the delivery of services that collectively may be regarded as equivalent to the T1 Service. Accordingly, although it is likely to be sought by a significant part of the market, I do not consider that it is necessary for the T1 Service to be offered as a Reference Service in order for the proposed Services Policy to comply with the Code.

64. As mentioned above, Epic Energy has described a number of services (described as Non-Reference Services in clause 6.1 of the proposed Access Arrangement), which it states are intended to complement its proposed Firm Service. These comprise the Secondary Market Service, Park and Loan Service, Seasonal Service, Peaking Service, Metering Information Service, Pressure and Temperature Control Service, Odorisation Service, and Co-mingling Service.

65. I have considered each of these services and I am of the view that each of the services listed in the proposed Access Arrangement under the heading of Non-Reference Services are services that are likely to be sought by a significant part of the market and I am of the opinion that they should be included in the Services Policy.

66. Further, with respect to these Non-Reference Services, the proposed Access Arrangement does not provide any descriptive information as to the nature of the proposed Non-Reference Services. Some of the proposed Non-Reference Services (Secondary Market Service, Seasonal Service and Park and Load Service) are described in the "Definitions" section of the Access Arrangement and in clause 5 of the Access Guide submitted by Epic Energy together with the proposed Access Arrangement, although the Access Guide does not form part of the Access Arrangement or the Access Arrangement Information.

67. I have some concern that simply specifying the "names" of services, as indicated in the list of Non-Reference Services provided by Epic Energy as part of its Services Policy, does not adequately describe those services, taking into account the requirement of section 3.2(a) that the Services Policy include a description of the Services the Service Provider will make available to Users and Prospective Users. However, I note that the list of services utilises terms that have generally understood meanings within the gas transmission industry. In addition, there have been no submissions made to me requesting that more descriptive information be provided. Accordingly, for the purposes of considering whether to approve the Access Arrangement currently before me, I am now of the view that, provided that Epic Energy commits to providing the Non-Reference Services, no further descriptive information in the Access Arrangement itself is needed to comply with section 3.2(a) of the Code.

68. Further, I have considered whether it is appropriate for these services to be offered as discrete Non-Reference Services – as proposed by Epic Energy – or whether there are reasons why they should be offered as part of a Reference Service similar to the Firm Service, or as individual Reference Services.

69. In regard to the Seasonal Service, I note as a preliminary observation that it appears technically and commercially feasible for a Seasonal Service to be offered as a component of the Firm Service; that is, to allow Users to contract for different levels of MDQ in different parts of a year rather than contracting for a constant level of MDQ over the full year. Capacity in the pipeline that would be available on a seasonal basis and which may be offered for the period when it is available is not different from capacity otherwise offered under the Firm Service, except in that it is only available for part of the year. I further note that there is a demonstrated historical demand for seasonal variation in contracted capacity by Users such as AlintaGas and Western Power.

70. Epic Energy has objected to the inclusion of a Seasonal Service as a part of the Firm Service for the reasons summarised as follows.

- Requiring that the capacity available for Firm Service be determined by combining the seasonal component of capacity with the base firm capacity (defined in terms of the January average) limits Epic Energy's opportunity to schedule maintenance in those periods when either excess capacity is available, or the demand for the available capacity is relatively low.

- Requiring Epic Energy to allow Users to contract for additional capacity on a seasonal basis as part of the Firm Service has the effect of increasing the level of capacity that Epic Energy must provide as the Firm Service, without any compensation to Epic Energy for significant extra risk borne by Epic Energy.

- Requiring Epic Energy to allow Users to contract for additional capacity on a seasonal basis as part of the Firm Service may have the effect of reducing the "base-line" capacity of the pipeline below the currently defined level, resulting in an outcome inconsistent with the economically efficient operation of the pipeline.

- Allowing Users to contract for seasonal capacity as part of the Firm Service restricts the flexibility of Epic Energy in the offering of this service, according to capacity that becomes available as a result of particular scheduling of pipeline maintenance. To the extent to which this may compromise the conduct of maintenance, the requirement may be inconsistent with ensuring the safe and reliable operation of the pipeline.

- Allowing Users to contract for seasonal capacity as part of the Firm Service restricts the ability of Epic Energy to offer additional capacity on a seasonal basis by charging a higher price (than the Reference Tariff) for the seasonal capacity and using the additional revenue gained to alter maintenance schedules or inventories of spare parts, according to capacity that becomes available as a result of particular scheduling of pipeline maintenance.

- The requirement for amendment of the Firm Service to incorporate the Seasonal Service is not justified in terms of the test established by the Code that a

Reference Service (and presumably a component of a Reference Service) must be a service which is likely to be sought by a significant part of the market. While the Regulator included in the Draft Decision a conclusion that "the demand for the Seasonal Service should be readily predictable and there is no reason why such demand should not be taken into account in determining the Reference Tariff", this conclusion was not supported. The justification used by the Regulator was an historical use of seasonal capacity, but this historical use was taken out of context inasmuch as the seasonal use of capacity by some Users reflected the historical definition of pipeline capacity (under the tranche system) and special provision for use of capacity on a seasonal basis by the relevant Users – Western Power and AlintaGas.

- The Regulator has not demonstrated that Epic Energy's proposed Firm Service fails to meet the test for a Reference Service (in the absence of incorporation of the Seasonal Service).

71. Epic Energy submitted that combining a Seasonal Service with the Firm Service has a number of effects on management and operation of the pipeline, including:

- limiting Epic Energy's opportunity to schedule maintenance in those periods when either excess capacity is available, or the demand for the available capacity is relatively low;
- increasing the level of capacity that Epic Energy must provide as the Firm Service, without any compensation to Epic Energy (through a higher tariff) for extra costs incurred as a result of significant extra risk borne by Epic Energy, and of higher costs of maintenance (to provide the additional capacity); and
- potentially limiting Epic Energy's ability to operate the pipeline safely and reliably.

72. The technical and operational difficulties identified by Epic Energy would not necessarily result from the facility to contract for capacity on a seasonal basis in the Firm Service. Incorporating a Seasonal Service into the Firm Service only provides for Users to contract for different service levels in different months of the year subject to the constraints of pipeline capacity. It would not impose any obligation on Epic Energy to define capacity of the pipeline at any particular level. Epic Energy would remain able to specify the capacity of the pipeline to provide the Firm Service, including any seasonally available capacity, in accordance with maintenance schedules. No obligation would be imposed on Epic Energy to operate the pipeline other than in accordance with its own standards for safety and reliability.

73. As a further matter, the operational and commercial issues identified by Epic Energy are inconsistent with other information that Epic Energy has provided to me. Epic Energy has indicated that the proposed Seasonal Service would be offered under the same terms and conditions as the Firm Service[5] and for the same tariff.[6] This would

[5] Epic Energy (WA) Transmission Pty Ltd, 15 December 1999, Proposed Access Guide under the National Access Code, Submission Version pp 9,10.

suggest that capacity will exist on a seasonal basis to provide the Firm Service, taking into account the scheduling of maintenance tasks and without any compensation for increased maintenance requirements or the bearing of additional risk in service provision.

74. There has historically been a significant demand for pipeline capacity on a seasonal basis. Offering a Seasonal Service as a Reference Service would promote the interests of current Users insofar as a seasonal Reference Service and the Firm Service together would relatively closely resemble the existing T1 Service. These factors would provide justification for me to require that a Seasonal Service be included in the Access Arrangement as a Reference Service. Against these factors, however, I weigh the advantages of the arrangement proposed by Epic Energy whereby the Seasonal Service is provided as a Non-Reference Service with a portion of revenues derived from sale of this service being rebated to Users. This arrangement would provide substantial incentive for Epic Energy to develop the market for seasonal capacity. In the circumstances, and provided that Epic Energy describes the Seasonal Service in the Access Arrangement as a service to be provided, I am of the view that the proposed arrangement is appropriate.

75. In conclusion, as set out above I have assessed the Services Policy of the proposed Access Arrangement under section 3.2 of the Code and taken into account the factors set out in section 2.24 where appropriate.

76. I am of the view that each of the services currently listed as Non Reference Services should be included in the Services Policy as services that Epic Energy will make available.

77. I am of the view that the proposed Access Arrangement should include a Reference Service with the characteristics of the Firm Service but allowing for receipt of gas at locations outside of Zone 1 of the pipeline, a minimum contract term of no more than two years, and including provision for the provision of metering information, reflecting an appropriate balance of interests under section 2.24 of the Code.

78. Provided that Epic Energy's Services Policy describes the services offered, this will make available the delivery of services that collectively may be regarded as equivalent to the T1 Service. Accordingly, although it is likely to be sought by a significant part of the market, I do not consider that it is necessary for the T1 Service to be offered as a Reference Service in order for the proposed Services Policy to comply with the Code.

[6] Epic Energy (WA) Transmission Pty Ltd, 31 December 2002, Court Decision Submission CDS#5: response to Draft Decision Amendments, p13.

Reference Tariff and Reference Tariff Policy

Requirements of the Code

79. Section 3.3 of the Code requires that an Access Arrangement include a Reference Tariff for:

> (a) at least one Service that is likely to be sought by a significant part of the market; and
>
> (b) each Service that is likely to be sought by a significant part of the market and for which the Relevant Regulator considers a Reference Tariff should be included.

80. Section 3.4 of the Code makes cross reference to section 8 of the Code for the principles with which a Reference Tariff must comply:

> Unless a Reference Tariff has been determined through a competitive tender process as outlined in sections 3.21 to 3.36, an Access Arrangement and any Reference Tariff included in an Access Arrangement must, in the Relevant Regulator's opinion, comply with the Reference Tariff Principles described in section 8.

81. Section 3.5 of the Code requires that, in addition to a Reference Tariff, an Access Arrangement must include a Reference Tariff Policy:

> An Access Arrangement must also include a policy describing the principles that are to be used to determine a Reference Tariff (a Reference Tariff Policy). A Reference Tariff Policy must, in the Relevant Regulator's opinion, comply with the Reference Tariff Principles described in section 8.

82. As referred to in sections 3.4 and 3.5 of the Code, section 8 of the Code sets out the principles with which Reference Tariffs and a Reference Tariff Policy included in an Access Arrangement must comply.

83. Section 8.1 of the Code provides that a Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objectives:

> (a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;
>
> (b) replicating the outcome of a competitive market;
>
> (c) ensuring the safe and reliable operation of the Pipeline;
>
> (d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;
>
> (e) efficiency in the level and structure of the Reference Tariff; and
>
> (f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

84. Section 8.1 of the Code also provides guidance as to the reconciliation of these objectives:

> To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

85. In respect of the reconciliation of objectives of section 8.1 of the Code, I note the direction provided by the third of the Declaratory Orders:

3. The factors in s 2.24(a) to (g) should guide the Regulator in determining, if necessary, the manner in which the objectives in s 8.1(a) to (f) can best be reconciled or which of them should prevail.

86. In addition to the objectives set out in section 8.1 of the Code, section 8.2 of the Code requires that I be satisfied about a number of factors in determining to approve a Reference Tariff and Reference Tariff Policy:

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

(b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total revenue that a Reference Tariff is designed to recover (which may be based on forecasts) is calculated consistently with the principles contained in this section 8;

(c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in section 8;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 8; and

(e) any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

87. The principles contained in section 8 and referred to in sections 8.2(a) to (d) include:

- principles for the form of regulation and variation of Reference Tariffs;
- methodologies for determining the Total Revenue;
- principles for determining the Capital Base;
- principles for determining the Rate of Return;
- principles for the Depreciation Schedule;
- provision for Non Capital Costs to be factored into the Reference Tariff if prudent;
- principles for determining the portion of Total Revenue that a Reference Tariff should be designed to recover from sales of the Reference Service, and the portion of revenue that should be recovered from each User of that Reference Service;
- principles concerning the use and design of Incentive Mechanisms;
- a mechanism whereby certain parts of the Reference Tariff Policy cannot be changed at a review of the Access Arrangement for a certain period; and
- principles for the charging of Surcharges in relation to Incremental Capacity.

88. Epic Energy has provided a Reference Tariff Policy in clause 7 of the proposed Access Arrangement. The proposed Reference Tariff Policy addresses the following matters.

- *General Principles* – indicating that Reference Tariffs are designed to recover from Users of the Reference Service the avoidable costs attributable to each User and a share of joint costs; and that the Reference Tariff has been determined on the basis of the gas specifications prescribed in the Access Contract Terms and Conditions.

- *Calculation of Total Revenue* – indicating that Total Revenue has been calculated on a cost-of-service basis.

- *Calculation of the Initial Capital Base* – outlining in general terms the operation of Epic Energy's "deferred recovery account" method of asset depreciation and indicating that the Capital Base for the DBNGP at the beginning of each year of the Access Arrangement is the sum of a physical account balance and a deferred recovery account balance.

- *Return on Assets* – indicating that the return on assets is determined by multiplying the Capital Base at the beginning of each year of the Access Arrangement by the Rate of Return.

- *Calculation of the Rate of Return* – indicating that the Rate of Return is determined as a weighted average of the returns to debt and equity, with return on equity determined by the Capital Asset Pricing Model ("**CAPM**") methodology and return on debt determined as the sum of a risk free rate of return and the estimated corporate debt premium.

- *Depreciation Schedule* – indicating depreciation of the physical asset account by an annuity method, and indicating in general terms the method of capitalisation of "losses" to the deferred recovery account or of depreciation of that account.

- *Non Capital Costs* – indicating that the Reference Tariff provides for the recovery of all Non Capital Costs to the extent permitted under section 8.37 of the Code.

- *Forecast Capital Expenditure* – indicating that the New Facilities Investment forecast of the Access Arrangement Period is reasonably expected to pass the requirements of section 8.16 of the Code, and providing for "rolling-in" of New Facilities Investment into the Capital Base at the commencement of the next Access Arrangement Period.

- *Allocation of Costs Between Services* – indicating that costs are allocated across Users of the DBNGP as if all Users are Users of the Reference Services, and that no costs are allocated to the provision of Rebatable Services.

- *Allocation of Costs Between Users* – indicating that costs are allocated to Users of the Firm Service on the basis of use of assets of the DBNGP, that a Reference Tariff is specified on the basis of 11 pipeline zones, and that the Reference Tariff for the Firm Service comprises five components: gas receipt charge, pipeline capacity charge, compression capacity charge, compressor fuel charge and Delivery Point charge.

- *Form of Regulation* – indicating that the Reference Tariff is specified by a price-path approach, with annual inflation at two thirds of changes in the Consumer Price Index (**"CPI"**).

- *Use of Incentive Mechanisms* – indicating that the price-path approach to the specification of the Reference Tariff provides incentives to develop the market and reduce costs, and that a method for distribution of rebatable revenue provides incentives for Epic Energy to develop a market for that part of the DBNGP capacity which cannot otherwise be made available as Firm Service.

- *New Facilities Investment* – indicating that Epic Energy will observe and comply with Code requirements regarding New Facilities Investment.

- *Adjustment of Tariff* – indicating that the Reference Tariff may be varied pursuant to clause 16 of the Access Contract Terms and Conditions (relating to pass through of costs arising from changes in supply taxes and changes in the regulatory environment).

- *Reference Tariff Principles Not Subject to Review* – indicating that the Initial Capital Base is a fixed principle for the purposes of section 8.47 of the Code.

89. In determining whether to approve or not approve the proposed Access Arrangement, I must reach a view on whether the proposed Reference Tariff and Reference Tariff Policy comply with the principles of section 8 of the Code, guided by the objectives of section 8.1 and, as necessary to resolve conflict between these objectives, the factors of section 2.24(a) to (g).

90. In forming my view on whether the proposed Reference Tariff and Reference Tariff Policy comply generally with the principles and objectives of section 8 of the Code, I examined the components of Epic Energy's cost-of-service derivation of Total Revenue and the Reference Tariff for the Firm Service against the relevant principles contained in section 8 of the Code. My considerations in this regard are summarised as follows.

Form of Regulation and Variation of the Reference Tariff

91. Section 8.3 of the Code indicates a range of methods by which a Reference Tariff may be varied within an Access Arrangement Period:

> 8.3 Subject to section 8.3A and to the Relevant Regulator being satisfied that it is consistent with the objectives contained in section 8.1, the manner in which a Reference Tariff may vary within an Access Arrangement Period through the implementation of a Reference Tariff Policy is within the discretion of the Service Provider. For example, the Reference Tariff Policy may specify that Reference Tariffs will vary within an Access Arrangement Period through the implementation of:
>
> (a) a Cost of Service Approach;
>
> (b) a Price Path Approach;
>
> (c) a Reference Tariff Control Formula Approach;
>
> (d) a Trigger Event Adjustment Approach; or
>
> (e) any variation or combination of the above.

92. Epic Energy has used a price-path methodology for the specification of the Reference Tariff. With this approach, the Reference Tariff is specified in advance for the Access Arrangement Period. The Reference Tariff follows a path that is not adjusted to account for subsequent events (other than economy wide inflation as measured by the CPI) until the commencement of the next Access Arrangement Period.

93. I am satisfied that the price-path methodology adopted by Epic Energy is consistent with the objectives of section 8.1.

Initial Capital Base

94. Section 8.4 of the Code describes three alternative methodologies for determining the revenue to be generated from the sales (or forecast sales) of all services over the Access Arrangement Period ("**Total Revenue**"). All three of the methodologies require, for their application, a valuation of the capital assets that form the Covered Pipeline at the commencement of the Access Arrangement Period ("**Capital Base**").

95. Sections 8.10 and 8.11 of the Code state the principles for establishing the Capital Base when a Reference Tariff is first proposed for a Reference Service provided by a pipeline that was in existence at the commencement of the Code ("**Initial Capital Base**"). These principles apply to the proposed Access Arrangement for the DBNGP.

96. Section 8.10 of the Code requires that a range of factors be considered in establishing the Initial Capital Base:

> 8.10 When a Reference Tariff is first proposed for a Reference Service provided by a Covered Pipeline that was in existence at the commencement of the Code, the following factors should be considered in establishing the initial Capital Base for that Pipeline:
>
> (a) the value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to users (or thought to have been charged to users) prior to the commencement of the Code;
>
> (b) the value that would result from applying the "depreciated optimised replacement cost" methodology in valuing the Covered Pipeline;
>
> (c) the value that would result fom applying other well recognised asset valuation methodologies in valuing the Covered Pipeline;
>
> (d) the advantages and disadvantages of each valuation methodology applied under paragraphs (a), (b) and (c);
>
> (e) international best practice of Pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries;
>
> (f) the basis on which Tariffs have been (or appear to have been) set in the past, the economic depreciation of the Covered Pipeline, and the historical returns to the Service Provider from the Covered Pipeline;
>
> (g) the reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code;
>
> (h) the impact on the economically efficient utilisation of gas resources;
>
> (i) the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a Pipeline that may by-pass some or all of the Pipeline in question);

> (j) the price paid for any asset recently purchased by the service provider and the circumstances of that purchase;
>
> (k) any other factors the Relevant Regulator considers relevant.

97. In considering Epic Energy's proposed Initial Capital Base, I have given consideration to the fourth of the Declaratory Orders:

> 4. The factors in s 8.10(a) to (k) are relevant to, and are to be given weight as fundamental elements in, the establishment of the initial Capital Base of the pipeline.

98. Section 8.10 of the Code sets out only a range of matters to be considered in establishment of the Initial Capital Base of the DBNGP. As noted by the Court, the factors set out in section 8.10:[7]

> … bring into account a number of matters which are not directly related to the value of the pipeline in the ordinary sense, and which by their nature require consideration of disparate issues which may well tend in different directions.

99. The Court has noted that the exercise of my discretion is required in establishing the value of the Initial Capital Base, taking into account the factors of section 8.10:[8]

> The process is more than one of mere valuation. There is necessarily, a discretionary evaluation of what weight should be attached to each of these factors in the ultimate establishment of the Capital Base.

100. Guidance for my discretionary evaluation is provided by other sections of the Code, notably sections 8.11, 8.1, and section 2.24.

101. Section 8.11 of the Code states that the Initial Capital Base for Covered Pipelines that were in existence at the commencement of the Code normally should not fall outside the range of values determined under paragraphs (a) and (b) of section 8.10.

102. In relation to section 8.11, the Court noted that:[9]

> ... notwithstanding the variety of values and other factors which s 8.10 requires to be considered, there is the principle stated in section 8.11 that the initial capital base "normally should not fall outside the range of values determined under" s 8.10(a) and (b). There is an obvious tension between the requirement of s 8.10 to consider factors (c) to (k) in establishing the Capital base and the provision in s 8.11 that, normally, the resulting Capital base should not fall outside the range determined under factors (a) and (b). The process clearly involves the exercise of discretion in the weighing of divergent considerations.

103. The Court indicated that the principles of section 8.1 of the Code provide the objectives that a Regulator must seek to achieve in the establishment of the Initial Capital Base for a pipeline, and hence the principles of section 8.1 that guide me in the exercise of my discretion.[10] However, the Court also indicated that the objectives of section 8.1 may conflict in their application, in which event the factors set out in

[7] [2002] WASCA 231 para 74.

[8] [2002] WASCA 231 para 74.

[9] [2002] WASCA 231 para 75.

[10] [2002] WASCA 231 para 75, 84.

section 2.24(a) to (g) guide me in determining "the manner in which they can best be reconciled or which of them should prevail".[11]

104. Epic Energy has proposed an Initial Capital Base of $2,570.34 million as at 31 December 1999. Epic Energy has indicated that this value was derived as follows.[12]

- Summation of the 1998 DBNGP purchase price of $2,407 million and $42.49 million of associated acquisition costs[13] to obtain a total acquisition cost of $2,449.49 million.
- Allocation of the total acquisition cost across classes of assets on the basis of assessed market values of individual assets.[14]
- Adjustment of the asset value in each asset class to reflect depreciation and capital expenditure to 31 December 1999, giving a value for each asset class as at 31 December 1999, and a total value across all asset classes of $2,570.34 million.

105. A breakdown of the proposed Initial Capital Base across asset classes is provided in section 3.2 of the Access Arrangement Information and reproduced as follows.

[11] [2002] WASCA 231 para 85.

[12] Access Arrangement Information, 28 July 2000, section 3.2.

[13] Indicated by Epic Energy to include borrowing expenses and other costs associated with the acquisition, and net adjustments for spares, linepack and construction work in progress (Epic Energy response to OffGAR Information Request 6, section 3.2).

[14] The valuation of individual assets was undertaken for Epic Energy by Edward Rushton Australia Pty Limited. Epic Energy advised that it was unable to provide the Regulator with details of the market valuations of individual assets that formed the basis for allocation of the total asset value to individual assets or the details of the allocation, for the reason that Epic Energy does not have this information. (Epic Energy, 22 December 2000, Information Request 8: Asset Valuation and Method Used to Assign Values to Specific Pipeline Assets.)

Proposed Initial Capital Base by Asset Class

Asset	Asset Value at 31 December 1999 ($ million)
Pipeline assets	
Zone 1a	33.20
Zone 1b	300.85
Zone 2	162.65
Zone 3	163.19
Zone 4	163.61
Zone 4a	67.49
Zone 5	166.19
Zone 6	167.99
Zone 7	189.50
Zone 8	169.30
Zone 9	229.41
Zone 10	290.45
Compression assets	
Compressor station 1	24.30
Compressor station 2	26.34
Compressor station 3	44.90
Compressor station 4	25.57
Compressor station 5	45.39
Compressor station 6	49.96
Compressor station 7	24.59
Compressor station 8	46.30
Compressor station 9	51.15
Compressor station 10	13.91
Metering assets	28.90
Other assets	
Depreciable	79.37
Non-depreciable (land and pipeline linepack)	5.82
Total	**2,570.34**

106. In considering the factors of section 8.10 of the Code, section 8.10(a) requires that consideration be given to:

> The value that would result from taking the actual capital cost of the covered pipeline and subtracting the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code.

107. The value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users is referred to for the purposes of this Final Decision as the Depreciated Actual Cost (**"DAC"**).

108. Epic Energy provided me with an estimate of the DAC value of the DBNGP of $2,466.1 million, determined as the acquisition cost of the DBNGP to Epic Energy,

less the sum of "the amount of depreciation [Epic Energy] believes SECWA and AlintaGas (as prior owners of the DBNGP) have collected from third parties (including the Trading Division of AlintaGas)" and "the amount of depreciation recovered by Epic Energy from third parties since it has owned the DBNGP".[15]

109. Epic Energy's reasons for considering the DAC value to appropriately be derived from the acquisition cost were outlined in detail in my Draft Decision.[16] In summary these were:

- that "actual capital cost of the Covered Pipeline" refers to the value of capital investment in the assets by the current owner of the assets, regardless of whether or not this investment comprised the construction cost of assets or the cost of purchase of existing assets; and

- that "accumulated depreciation charged to Users (or thought to have been charged to Users) prior to the commencement of the Code" refers to explicit depreciation components of gas transmission tariffs charged to third parties provided with a gas transmission service.

110. In the Draft Decision, I took a different view in respect of both the definition of "actual capital cost" and the nature of depreciation taken into account in calculation of a DAC value:[17]

- "actual capital cost" has the meaning of the cost of construction of the relevant assets; and

- "accumulated depreciation charged to Users (or thought to have been charged to Users) prior to the commencement of the Code" includes implicit or explicit depreciation charges to the owner transporting gas on its own behalf.

111. I made estimates of the DAC value based on the book value of the pipeline assets as at 30 June 1997, and on the basis of the actual cost of the DBNGP and depreciation charges levied on persons directly or indirectly using the pipeline services through tariffs for either delivery of gas or provision of gas transmission services. The values that I calculated are:

- $1030.2 million as at 31 December 1999, derived from the book value at 30 June 1997; and

- $874.0 million as at 31 December 1999, derived from actual capital expenditure and capital recovery.

112. Epic Energy has submitted to me that calculation of DAC values in this manner is not in accordance with the Code. Epic Energy has also submitted that the latter value calculated by me:

---

[15] Access Arrangement Information, 28 July 2000, p 32.

[16] Draft Decision Part B pp 120–123.

[17] Draft Decision Part B pp 123–128

- is approximate as it is based on general assumptions which have not been substantiated by me and does not include amounts of capital recovery for certain laterals and metering facilities; and
- is based on a limited amount of accurate information available to properly determine the actual historical cost of construction of the pipeline.

113. I maintain the position that the determination of the DAC value on the basis of historical construction costs is the appropriate interpretation of the Code. While the term "actual cost" is not defined in the Code, use of the term throughout section 8 of the Code, including in relation to both the Initial Capital Base and New Facilities Investment, is consistent with a meaning of the cost of construction of the relevant assets. This is also consistent with the approach indicated by the reasons of the Full Court.[18]

114. I acknowledge the difficulty in accurately estimating the DAC value from incomplete information concerning the historical construction costs. However, I am of the view that I have sufficient information to adequately estimate the DAC value for the purposes of the Code.

115. I find $874 million to be the value under section 8.10(a) of the Code.

116. Section 8.10(b) of the Code requires that consideration be given to:

> the value that would result from applying the Depreciated Optimised Replacement Cost methodology in valuing the covered pipeline.

117. Epic Energy provided me with an estimated DORC value of the DBNGP of $1,368.4 million as at 1 January 2000.[19] This estimate was based on the principal assumptions of a greenfields development, and the notional replacement pipeline being constructed in stages, with the same staging of capacity augmentation as occurred in the historical construction of the DBNGP, although with optimisation of each stage of construction in deriving the DORC estimate.[20] The effect of this approach is that the engineering optimisation for the hypothetical replacement pipeline is undertaken within the constraints of there being no differences in gross design parameters between the existing pipeline and the hypothetical "optimised" pipeline on which the DORC value is based.

118. In coming to my Draft Decision, I reviewed Epic Energy's DORC valuation for the purposes of identifying any manifest errors, omissions or inadequacies in the methodology or assumptions used in the DORC valuation, and to provide indicative estimates made as to the magnitude of any resultant error introduced into the DORC valuation. It is my view that assumptions made by Epic Energy in respect of optimised pipeline design (in particular assumptions that an optimised pipeline would be built as a "greenfields" development and that the pipeline would be built in a staged approach resembling its actual construction history) and depreciation (use of

[18] [2002] WASCA 231 para 163.

[19] Access Arrangement Information, 28 July 2000, p 32.

[20] Epic Energy (WA) Transmission Pty Ltd, 25 October 2000, Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 7.

annuity rather than straight-line depreciation and assumptions of very long asset lives) result in Epic Energy's proposed DORC valuation overstating a reasonable DORC estimate by an amount in the order of $270 million.

119. For the purposes of establishing a DORC value of the DBNGP at 31 December 1999, I considered it appropriate to include the Stage 3A pipeline expansion in total. This requires transferring some of Epic Energy's forecast Capital Expenditure for the year 2000 into the initial asset valuation. With this adjustment, the Epic Energy estimated DORC value would be $1,493.6 million. With correction to this value to reflect potential over-estimation of the DORC value, the Epic Energy DORC value is revised to $1,227.41 million.

120. A further source of information that I considered in relation to the DORC value of the DBNGP was the Optimised Replacement Cost and DORC values that were determined in 1997 for the purposes of providing information to prospective purchasers of the DBNGP as to the possible valuation of the pipeline assets under the Code.[21] Using the 1997 estimate of the DORC value, I derived a valuation of the DBNGP as at 31 December 1999 by escalating the Optimised Replacement Cost value to account for inflation, depreciating over assumed asset lives consistent with my revision of Epic Energy's estimated DORC value, and adding capital expenditure (adjusted for inflation and depreciation) in the years 1998 and 1999 and associated with the Stage 3A pipeline expansion. I thus estimated a DORC value of $1,233.7 million, which is close to the value obtained by revision of the estimated DORC value provided by Epic Energy.

121. I accept that there is some unavoidable imprecision in estimation of DORC values by virtue of different assumptions made as to optimisation of assets, assumptions as to asset lives and different assumptions as to costs. I therefore accept that reasonable estimates of DORC values for the same asset may vary and that this variation may be up to a level in the order of 20 percent about a central value. Taking this into account, the value I have determined in accordance with section 8.10(b) of the Code is $1,230 million ± $200 million.

122. Section 8.10(c) of the Code requires that consideration be given to:

> the value that would result from applying other well recognised asset valuation methodologies in valuing the Covered Pipeline.

123. In my Draft Decision, I gave attention to three alternative valuations of the Initial Capital Base, all in response to valuations put forward by Epic Energy:

- Optimised Deprival Value, being determined as the lesser of the optimised replacement cost of the asset and the net present value of cash flows given assumptions as to future tariffs, having a value determined in this case as the optimised replacement cost of $1,527.9 million;

[21] CMPS&F Pty Limited, 1997, Dampier to Bunbury Natural Gas Pipeline Optimised Replacement Cost, document no. PW0972/OLW390 prepared for Price Waterhouse; Price Waterhouse Chartered Accountants, answer to data room question no. 29, Dampier to Bunbury Natural Gas Pipeline Gas Pipeline Sale Steering Committee, 16 February 1998.

- an Imputed Capital Base, being a value of the Initial Capital Base determined by Epic Energy to be consistent with Epic Energy's proposed tariff path and throughput forecasts (without deferred depreciation), having a value determined at $1,750 million; and

- the "Purchase Price", being Epic Energy's proposed Initial Capital Base for the DBNGP assets of $2,570.34 million as at 31 December 1999 determined as the cost to Epic Energy of purchase of these assets as at 25 March 1998, with adjustments to account for depreciation and capital expenditure in the period from 25 March 1998 to 31 December 1999.

124. I have considered the following submissions made to me by Users in respect of these valuations.

- The Imputed Value is not an appropriate measure given that Epic Energy's assumptions as to future tariffs (the tariff path as proposed for the Access Arrangement) are not supported by the Sale Process or sale agreement as Epic Energy claims.

- Purchase Price does not comprise a "well recognised asset valuation methodology", but rather it is "market value" that comprises the relevant valuation methodology and purchase price is just an indicator of market value.

125. Imputed Value as an appropriate asset valuation methodology relies on support of assumptions as to the future tariff path. My consideration of Epic Energy's assumptions as to future tariffs in the context of section 8.10(j) of the Code leads me to accept that Imputed Value is not an appropriate asset valuation methodology in this case.

126. I also accept the submissions in relation to Purchase Price, but I note that in some circumstances Purchase Price may represent market value and as such be an appropriate asset valuation methodology. However, my consideration of the Purchase Price in relation to section 8.10(j) supports a rejection of the Purchase Price as representing market value in the circumstances of this case.

127. Section 8.10(d) of the Code requires that consideration be given to:

> the advantages and disadvantages of each valuation methodology applied under paragraphs (a), (b) and (c).

128. Neither section 8.10(d) nor other provisions of section 8.10 provide guidance as to the assessment of advantages and disadvantages of different valuation methodologies. It is therefore necessary to look outside of section 8.10 for objectives and criteria against which advantages and disadvantages may be determined. For this purpose, I have given consideration to the objectives of a Reference Tariff and Reference Tariff Policy as set out in section 8.1 of the Code.

129. Section 8.1(a) of the Code indicates that a Reference Tariff and Reference Tariff Policy should be designed with a view to providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service. The Court has provided some guidance in interpretation of section 8.1(a),

emphasising that section 8.1(a) refers to an *opportunity* for the Service Provider to earn a "stream of revenue" that recovers efficient costs over the expected life of the assets used and that this should not be interpreted as implying that the Service Provider be allowed "at least" efficient costs, nor limited to "at most" efficient costs.[22]

130. In considering the notion of "efficient costs", the Court held that

> the word "efficient" in a code dealing with the regulation of infrastructure in the context of competition policy reform, and in which the concept of "economic efficiency" has been expressly incorporated, strongly suggests a usage which comprehends and reflects that notion in its accepted senses of technical or productive, allocative and dynamic efficiency.[23]

131. In the context of valuation of the Capital Base and "recovery of efficient costs", I have considered two concepts of efficient cost.

- Firstly, costs and efficiency may be considered from an historical perspective, i.e. that the Service Provider should be provided with the opportunity to recover capital costs that were "efficient" at the time the costs were incurred. Such a treatment of historical capital costs would be consistent with the treatment of New Facilities Investment. The cost of New Facilities Investment is rolled into the Capital Base provided that in terms of section 8.16(a) it does not exceed "the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services.

- Secondly, efficient costs can be considered from a forward-looking perspective, i.e. that the Service Provider should be given the opportunity to recover the forward-looking minimum cost of either asset replacement at the end of the life of the asset, or capital investment of a replacement or renewal nature that is necessary to maintain the service capacity of the asset.

132. A DAC value, being equal to the un-recovered capital costs of the pipeline assets, may be consistent with the former of these two concepts of efficient costs if the historical costs of construction were efficient at that time. A DAC valuation is not, however, necessarily consistent with the latter concept of efficient costs. From a forward-looking perspective in regulation, a DAC valuation of assets means that tariffs are not necessarily being determined on the basis of efficient capital costs and "best-practice" in provision of services, nor necessarily taking into account redundancy or obsolescence of assets. As a consequence, I am of the view that a revenue requirement calculated on the basis of an historical cost of assets does not necessarily bear any relation to a Service Provider's forward-looking costs for maintenance and replacement of capital assets. Again, the older the assets and the greater the extent of changes in price levels and relative prices since the time of capital investment, the more likely it is that a DAC value will not reflect a forward-looking efficient capital cost of service provision.

[22] [2002] WASCA 231 para 141.

[23] [2002] WASCA 231 para 139.

133. A DORC value is consistent with the forward-looking concept of efficiency, taking into account the costs of replacement assets with current technology and best practice, and being more consistent with the forward-looking costs of a Service Provider.

134. For the DBNGP, the DORC value exceeds the DAC value and, accordingly, the DORC value would meet the objective of section 8.1(a) under either concept of efficient costs, i.e. the DORC value would provide Epic Energy with the opportunity to recover the efficient costs of delivering the Reference Service, regardless of whether efficient costs are considered from a perspective of historical costs or forward-looking costs.

135. Similarly, given that values derived from the methodologies of Optimised Deprival Value, Imputed Value, or Purchase Price exceed the DAC and DORC values, valuation under any of these methodologies would provide Epic Energy with the opportunity to recover the efficient costs of delivering the Reference Service, regardless of which concept of efficient costs is considered. These other valuation methodologies are therefore also consistent with the objectives of section 8.1(a) of the Code.

136. Section 8.1(b) of the Code requires that a Reference Tariff and Reference Tariff Policy should be designed with a view to replicating the outcome of a competitive market.

137. The Court has indicated that the outcome of a competitive market should be interpreted in terms of a workably competitive market, and that the outcome of a competitive market is one of economic efficiency or, at least, greater efficiency, albeit not necessarily limited to only a forward-looking view of efficiency. Rather, the Court suggested that in a workably competitive market, past investments and risks taken may provide some justification for prices above the efficient level.[24] Accordingly, in this context, I have also given consideration to the purchase price paid by Epic Energy with a view to ensuring that the determination of the Capital Base in this case will not so prejudice the interests of Epic Energy that others will be reluctant to invest in a pipeline.

138. Taking into account the guidance provided by the Court, I take the view that valuation of pipeline assets consistent with the objective of section 8.1(b) requires that the valuation gives rise to tariffs that result in the revenue of the Service Provider being sufficient for the recovery of efficient capital costs, recognising both the "historical cost" and "forward-looking cost" perspectives of efficient costs as described above in relation to section 8.1(a) of the Code. Moreover, noting the view of the Court that in a workably competitive market, past investments and risks may be relevant, I consider that a valuation consistent with the objective of 8.1(b) may in some cases be greater than that which is just sufficient for recovery of efficient capital costs. An amount of the valuation in excess of efficient costs may be consistent with the objective of section 8.1(b) to the extent that it allows for recovery of historical investment that was reasonable at the time the investment was made, even if this investment may not be considered efficient in hindsight.

[24] [2002] WASCA 231 para 144, 145.

139. A DORC valuation of assets would meet that part of the objective of section 8.1(b) that involves a forward-looking view of efficient costs. A DORC valuation of assets would replicate the tariff outcomes of a competitive market, on the reasonable presumption that Service Providers in a competitive market would be forced by competitive pressures to value assets on an optimised replacement cost basis and to depreciate those assets at the lowest rate consistent with recovering sufficient revenue to replace the assets as and when the need arises.

140. To the extent that the DORC value of the DBNGP exceeds the DAC value, the DORC value would also be consistent with an historical perspective of efficient costs, inasmuch as a tariff based on the DORC value would provide the Service Provider with sufficient revenue to recover the residual (un-depreciated) value of historical capital investment.

141. By the same argument, tariffs corresponding to asset values that are greater than the DORC value (such as, in this case, the Optimised Deprival Value, Imputed Value and Purchase Price) would be greater than would be expected in a competitive market because these tariffs would allow for recovery of costs in excess of efficient costs. However, the Court has suggested that the reference to a competitive market in section 8.1(b) is to be read as a reference to a "workably competitive market" which allows for recovery of some level of historical investment that is in addition to what may be considered as efficient costs.

142. The other valuation methodologies advanced by Epic Energy would allow recovery of costs in excess of the capital investment involved in constructing the pipeline and therefore in excess of efficient costs. As noted above, the Court has found that in a workably competitive market past investments and risks taken may provide some justification for prices above the efficient level. Epic Energy has submitted that valuation of the Initial Capital Base on the basis of the price it paid for the Pipeline would be consistent with the objective of section 8.1(b) "to the extent that pricing in a workably competitive market can take account of past investments".[25] However, as was recognized by the Court (and the wording used in the submission by Epic Energy) this allowance is not unlimited. There is only an extent to which prices above the efficient level may be consistent with workable competition. This is because a workably competitive market provides a discipline so that where a price has been paid for an asset that did not properly reflect the risks associated with the future returns that may be obtained by using that asset over time to provide particular goods or services then the additional imprudent part of the price will not be able to be recovered. The value of the asset that can be recovered in the face of competition does not include the imprudent premium and the value of the asset has to be written down by the owner.

143. The fact that Epic Energy has paid a particular price in a tender process does not establish that the price it paid only exceeds the efficient level to the extent that past investments and risks would allow that to occur in a workably competitive market. Even in competitive markets some people pay more for assets than the market allows them to recover, even taking account of risks for other investors. For reasons given later in this decision when I deal with section 8.10(j) of the Code, I find that the price

[25] Epic Energy (WA) Transmission Pty Ltd 11 December 2002, Submission CDS#2 para 9.16.

paid by Epic Energy for the pipeline did not reflect reasonable commercial judgement, and for this reason may be beyond any premium for risk and past investment that a workably competitive market might allow to be recovered.

144. Section 8.1(c) of the Code requires that a Reference Tariff and Reference Tariff Policy should be designed with a view to ensuring the safe and reliable operation of the Pipeline.

145. The Court has interpreted this objective as requiring that attention be given in the design and assessment of every "Reference Tariff consideration" to ensuring that the revenue stream will be sufficient to meet safety and reliability needs as and when that is necessary.[26] In respect of valuation of the Initial Capital Base, this may imply that in order to ensure that a Service Provider is able to obtain sufficient revenue to operate the pipeline safely and reliably, a value of the Capital Base should be determined so as to ensure that, through the rate of return on this Capital Base, sufficient revenue is able to be generated by provision of the Reference Service at the Reference Tariff.

146. I note, however, that other elements of the Reference Tariff determination are also important to ensure that a Service Provider has adequate cash flows to ensure safe and reliable operation of a pipeline, including forecast operating expenditure, forecast capital expenditure and depreciation, which may also be set so as to affect the revenue able to be obtained by a Service Provider.

147. Meeting the objective of section 8.1(c) through the value of the Initial Capital Base would cause different values of the Initial Capital Base to be contemplated without reference to any particular methodology by which a value is derived. The objective set out in section 8.1(c) would thus appear to have little relevance to the consideration of advantages or disadvantages of particular valuation methodologies.

148. Section 8.1(d) of the Code requires that a Reference Tariff and Reference Tariff Policy should be designed with a view to not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries.

149. In examining the objectives of section 8.1(d) of the Code, the Court focussed on the first limb of this objective, being the objective of not distorting investment decisions in Pipeline transportation systems. The Court indicated that this has particular significance in relation to the DBNGP.[27] In respect of valuation of the Initial Capital Base, the Court considered the objective as requiring that consideration be given to the effect of past investments on incentives for future investment.[28] This gave rise to the following statement by the Court in relation to consideration of historical investments in pipelines:[29]

> 154 So understood, it would be consistent with the objective reflected in s 8.1(d) if the Regulator, in an appropriate case, were to accept or to take into account the actual investment of the

[26] [2002] WASCA 231 para 146.

[27] [2002] WASCA 231 para 147.

[28] [2002] WASCA 231 para 152.

[29] [2002] WASCA 231 para 154, 155 (italics in original).

owner in a Covered Pipeline which existed at the time the Act and Code came into force, when establishing the initial Capital Base. This is not to suggest that reckless, mistaken or highly speculative investment decisions should be accepted for this purpose. Such decisions, of course, would be likely to be recognised as such by other investors. However, by virtue of s 8.1(d), it would appear that the outcome under the Code of an investment decision in a pipeline made before the introduction of the Code, even though that decision anticipated some "monopoly" profits, would not be irrelevant to the Regulator's deliberations, under s 8, including the establishment of the initial Capital Base.

155 The reasons of the Regulator in the draft decision reveal that he was well alert to another relevant aspect of the operation of the first limb of s 8.1(d). Future investment decisions in pipelines might well be distorted were it the case that *any* price paid by a service provider to acquire a pipeline, no matter how uncommercial, mistaken or reckless, should automatically be recognised as the initial Capital Base or value of the pipeline for the purposes of the Code. This would encourage the payment of excessive and unrealistic prices to acquire a pipeline in the expectation that the purchase price would be able to be recovered over the life of the pipeline under the Code. It follows that a price paid for a pipeline before the Code applied to it, will need to be carefully evaluated by the Regulator for the purposes of s 8.1(d).

150. In response to guidance provided by the Court, I have given consideration to investment in the sense of:

- the actual historical cost of construction of the assets; and
- the purchase price of the assets.

151. As noted above in relation to the objective of section 8.1(a) of the Code, determination of an Initial Capital Base equal to or above the DAC value would provide for recovery of initial investment in construction of pipeline, and indeed is consistent with treatment of New Facilities Investment under the Code. A valuation methodology that derives an Initial Capital Base value at or above the DAC value should, therefore, provide sufficient comfort to other investors in pipelines that actual capital costs of pipeline constructions will be recognised in subsequent regulation, and hence not be to the detriment of incentives for efficient investment in pipeline construction.

152. Valuation of the Initial Capital Base of an existing pipeline at a value below the purchase price would not *necessarily* affect incentives to invest in, and operate, existing pipelines. In this regard, information provided to me by Epic Energy,[30] and confirmed by further research,[31] indicates that where values of the Initial Capital Base have been established for pipelines prior to the sale of those pipelines, sale prices are typically substantially in excess of the regulatory asset values.

153. There may also be broader considerations of incentives for investment in pipelines than treatment of past capital investment. For example, precedents established by the regulatory treatment of one pipeline may affect investment in other new or existing pipelines. An example of this is the possibility that establishing the Initial Capital Base of existing pipelines at a level in excess of DAC and DORC values would establish a precedent of more favourable regulatory treatment of an existing pipeline

[30] Epic Energy (WA) Transmission Pty Ltd, 25 February 2003, Submission CDAP#1.

[31] Annexure to Affidavit of Gregory John Houston in the Supreme Court of Western Australia No. 2166 of 2001.

than would apply to a new pipeline. The Initial Capital Base of a Covered Pipeline constructed after the commencement of the Code is determined as the actual capital cost of construction, without exercise of discretion by a regulator. If a higher Initial Capital Base (and hence higher regulated tariffs) could be achieved by investment in an existing pipeline, rather than construction of a new pipeline (all other things being equal), then there is potential distortion of investment incentives away from investment in new pipelines to investment in existing pipelines. This could potentially be at a substantial cost to the public through distortion of investment incentives away from investment in new infrastructure towards investment that comprises a mere refinancing and change of ownership of existing infrastructure.

154. In relation to the first limb of section 8.1(d) of the Code, I therefore take the view that distortion of incentives for investment in new pipelines may occur if the Initial Capital Base is valued by a methodology that gives rise to values substantially in excess of the value of construction of the pipeline infrastructure, i.e. a DAC or DORC value. In relation to the valuations considered in respect of the DBNGP, valuation of the Initial Capital Base at the Optimised Deprival Value, Imputed Value or Purchase Price would have the potential to distort future investment in pipelines, particularly in circumstances where the purchase price of the DBNGP was based upon unreasonable assumptions made by Epic Energy with respect to the level of returns that it may be able to earn in excess of efficient costs.[32]

155. The second limb of section 8.1(d) of the Code gives attention to incentives for investment in upstream and downstream industries. This limb of section 8.1(d) was given considerable attention in submissions to me by some Users of the DBNGP. Those submissions indicate, and I accept, that an asset value reflecting more than the efficient cost of the assets (DAC or DORC depending on whether an historical or forward-looking view is taken of efficient cost) would give rise to tariffs that result in higher costs to users of gas and reduce investment in both gas-using industries and up-stream gas production.

156. Section 8.1(e) of the Code requires that a Reference Tariff and Reference Tariff Policy should be designed with a view to efficiency in the level and structure of the Reference Tariff. The Court recognised that efficiency in section 8.1(e) is intended to reflect the concept of economic efficiency.[33]

157. The objective of section 8.1(e) has relevance to the determination of the Initial Capital Base insofar as it deals with the level of the Reference Tariff. To the extent that the Reference Tariff reflects an Initial Capital Base that is in excess of a value that reflects an efficient cost of the capital assets (DAC or DORC, reflecting different concepts of efficiency), the Reference Tariff is itself not efficient. It may thus be concluded that values of the Initial Capital Base in excess of the DORC value (in this case the Optimised Deprival Value, Imputed Value and Purchase Price) would be inconsistent with the objective of section 8.1(e) of the Code.

[32] Refer to the analysis of Epic Energy's purchase price in the discussion on section 8.10(j) of the Code (paragraph 185 and following).

[33] [2002] WASCA 231 para 156.

158. Epic Energy has submitted to me that determination of the Reference Tariff giving weight to the purchase price of the DBNGP would not be inconsistent with the objective of section 8.1(e) of the Code to the extent that recognition of past investment is necessary to prevent distortion of future investment.[34] However, as noted above in relation of section 8.1(d), setting of a value of the initial Capital Base lower than the purchase price would not necessarily distort investment as long as it is at least equal to or greater than the DAC and DORC values. Moreover, a value of the Initial Capital Base in excess of DAC and DORC, such as the value of the purchase price, may itself cause distortions in investment.

159. Section 8.1(f) of the Code requires that a Reference Tariff and Reference Tariff Policy should be designed with a view to providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

160. Provision of incentives for the Service Provider to develop the market for Reference Services and other services relates to the structure of a Reference Tariff and the Incentive Mechanisms in the Reference Tariff Policy, rather than the capital or other costs considered in derivation of the Reference Tariffs. Section 8.1(f) would therefore appear to have little direct bearing on the determination of advantages and disadvantages of alternative valuation methodologies for the Initial Capital Base.

161. Epic Energy contends that valuation of the Initial Capital Base at the purchase price is necessary to meet the objective of section 8.1(f) of the Code as it is necessary to demonstrate to finance providers that Epic Energy has the opportunity to earn a return on an Initial Capital Base established from the actual cost incurred by Epic Energy in purchasing the DBNGP.[35]

162. In so far as section 8.1(f) is relevant to assessing the Initial Capital Base, section 8.1(f) is of greater importance in establishing the structure of the Reference Tariff rather than the Initial Capital Base. The objective expressed in section 8.1(f) concerns the way in which tariffs and tariff policies can provide an incentive to reduce costs and to increase demand. The owner of an asset like a pipeline may have an incentive to maximise its profits by providing fewer services at a higher price. This is the basic market distortion of monopoly pricing. Section 8.1(f) is directed at ensuring that the owner of the pipeline has an incentive to make profits by reducing costs and increasing demand, rather than by increasing prices. It is difficult to see how this objective is advanced by setting an Initial Capital Base at a level that envisages that existing cost levels are covered rather than reduced.

163. It can be seen that the objectives in section 8.1 do not point to a particular valuation methodology being preferred. Rather, they identify a range of considerations to be brought to account in determining the Initial Capital Base. However, they do indicate that the Purchase Price would not be consistent with any of the objectives in section 8.1 to the extent that the Purchase Price did not reflect a reasoned judgment as to the value of the DBNGP at the time it was paid.

[34] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.21.

[35] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.23.

164. Returning to the factors of section 8.10 of the Code, section 8.10(e) of the Code requires that in establishing the Initial Capital Base for a Pipeline, consideration be given to international best practice of Pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries.

165. In regard to the first limb of section 8.10(e), in my Draft Decision I considered precedents for international practice in asset valuation for regulatory purposes are established in the UK and USA. I noted that regulators in the USA have historically relied upon historical cost valuations of assets as a basis for rate-of-return regulation. Regulators in the UK have tended to use replacement cost valuation methods of assets, such as DORC valuations, as a basis for price-cap or revenue-cap regulation.

166. I also made the observation in the Draft Decision that regulators in the UK have utilised a "market valuation" approach to valuing assets for privatised utility companies, typically involving establishing asset values as the market value of company stocks after some period of trading (as opposed to a "purchase price"), or some multiple or fraction of this value. In these cases, the market values have been below the value of replacement cost of assets, and multipliers greater than one have been applied on some occasions to cause the regulatory asset value to be closer to the replacement cost.[36] The rationale for adopting this valuation methodology has been the "fairness" of allowing investors to earn a reasonable rate of return on original investment. However, as market valuations depend on expectations of regulatory decisions and vice versa, it has been recognised that such a valuation approach could create a bias towards higher asset values.[37] I am not aware of any precedent for regulatory valuation of assets at a market value that is substantially in excess of a replacement cost valuation.

167. I also addressed Australian practice in my Draft Decision, noting that DORC valuations have been commonly viewed by other regulatory agencies in Australia as "starting points" for asset valuation, and that Initial Capital Base determinations have been close to or below DORC values.

168. Several submissions made to me by Users of the DBNGP and end-users of gas addressed the second limb of section 8.10(e) – the impact on energy consuming industries. Those submissions indicate, and I accept, that a value of the Initial Capital Base that is in excess of DORC will give rise to gas costs that will tend to reduce the international competitiveness of major industries in the south west of Western Australia.

169. Section 8.10(f) of the Code requires that, in establishing the Initial Capital Base for a pipeline, consideration be given to the basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the Covered Pipeline, and the historical returns to the Service Provider from the Covered Pipeline.

170. The Court has indicated that each of the considerations under section 8.10(f) has a potential relevance to past investment decisions in respect of the pipeline, particularly in a case where there has been a sale of the pipeline before the commencement of the

[36] Whittington, G., 1994. Current cost accounting: its role in regulated utilities, *Fiscal Studies* 15(4): pp 88-101.

[37] Whittington, G., 1994. Current cost accounting: its role in regulated utilities, *Fiscal Studies* 15(4): pp 88-101.

Code,[38] and that these provisions, along with provisions of section 8.10(g) reflect that part of the general objective of the Act and Code that the rights of access to third parties would be on conditions that are fair and reasonable for the owners and operators of the pipelines.[39]

171. In my Draft Decision, I indicated that the basis upon which tariffs had been set prior to Epic Energy's purchase of the DBNGP – under the *Gas Transmission Regulations 1994* – involved the regulatory asset value being considered on an historical cost basis, similar in concept to a DAC value.

172. In submissions made to me, some Users suggested that section 8.10(f) of the Code is not a relevant consideration in respect of the DBNGP, because Epic Energy purchased the DBNGP in full knowledge of the regulatory framework that would be established by the Code. Section 8.10(f) remains a relevant consideration. However, given that the sale of the DBNGP occurred in full knowledge (by both Epic Energy and many Users) of the impending application of the Code, and with a transitional access regime put in place, I take the view that in the circumstances of the present case little weight can be given to the factors in section 8.10(f) arising from the former regulatory regime applying under the *Gas Transmission Regulations 1994*. This is not a case where the same owner has moved from being subject to one regulatory regime to another.

173. Section 8.10(g) of the Code requires that, in establishing the Initial Capital Base for a pipeline, consideration be given to the reasonable expectations of persons under the regulatory regime that applied to the Pipeline prior to the commencement of the Code.

174. The Court deliberated on section 8.10(g) in much the same manner as 8.10(f), indicating that both paragraphs reflect the relevance of the historical returns and tariffs and depreciation, as well as the reasonable expectations of the Service Provider before the commencement of the Code. The Court indicated that it is more particularly 8.10(g) that may be seen to reflect that part of the general objective of the Act and the Code that rights of access to third parties would be on conditions that are fair and reasonable for the owners and operators of pipelines, and is consistent with the more precise expression of that general objective to be found in 2.24(a). The Court noted, however, that consideration of expectations under section 8.10(g) is not limited to consideration of the expectations of the Service Provider, but would also include the expectations of Users.[40]

175. In my Draft Decision, I gave consideration under section 8.10(g) to the expectations that a person may reasonably hold as to the value of tariffs and (explicitly or implicitly) the value of pipeline assets if those expectations were based solely on an assumption of the previous regulatory regime continuing into the future. The regulatory regime existing prior to the commencement of the Code (originating under the *Gas Transmission Regulations 1994*) determined tariffs on the basis of an asset valuation resembling a DAC value, although the written down asset value as at 31 December 1994 was a book value assigned to the assets on transfer from the

[38] [2002] WASCA 231 para 168.

[39] [2002] WASCA 231 para 169.

[40] [2002] WASCA 231 para 169.

SECWA to the newly formed Gas Corporation and may not have accurately reflected capital costs and subsequent depreciation. Notwithstanding this, if past regulation was to be used as an indication as to the likely outcomes of regulation under the Code, then it may be reasonably expected that an Initial Capital Base would be determined by a DAC-type valuation derived from the assumed written down value as at 31 December 1994, with subsequent adjustment for capital expenditure, depreciation and values of any transmission assets not transferred to Epic Energy as part of the DBNGP sale. The asset value determined in this way, and taking into account depreciation and capital expenditure to 31 December 1999, was estimated to be $1,270.1 million as at 31 December 1999.

176. I make the further observation now that, for the same reasons as indicated in respect of section 8.10(f), the regulatory regime applying under the *Gas Transmission Regulations 1994* may have limited relevance in terms of affecting the possible expectations of outcomes of regulation under the Code.

177. I do note, however, a submission from one User of the DBNGP that one element of the transitional arrangements put in place for the application of the Code to the DBNGP was provision for Users with contracts entered into under the *Gas Transmission Regulations 1994* to move to a transmission tariff determined as part of an Access Arrangement under the Code. On this basis, Users may have expected some consistency in determination of regulated tariffs, including in the valuation of assets, between regulation under the *Gas Transmission Regulations 1994* and under the Code. I further address this matter later in this decision when I examine the circumstances of the sale of the DBNGP (paragraph 189 and following).

178. Section 8.10(h) of the Code requires that in establishing the Initial Capital Base for a Pipeline consideration be given to the impact on the economically efficient utilisation of gas resources.

179. The Court has indicated that section 8.10(h) requires that consideration be given to principles of economic efficiency in the context of the utilisation of gas resources, rather than in the more limited focus of the operation of a natural gas pipeline.[41]

180. In my Draft Decision, I adopted an interpretation of this requirement from the then Victorian Office of the Regulator General, as a need to determine whether the valuation methodology that is selected is consistent with providing price signals that give incentives for the development and use of the most efficient source of gas for the relevant market. That is, the asset valuation methodology and gas transportation pricing regime should encourage the development and use of gas sources that minimise the (forward-looking) cost of gas exploration, extraction, transportation and supply to end users.[42]

181. On the basis of this interpretation, section 8.10(h) would generally require that the valuation of the Capital Base be consistent with providing the signals to investors in

[41] [2002] WASCA 231 para 170.

[42] Office of the Regulator General, Victoria, May 1998. Access Arrangements – Multinet Energy Pty Ltd & Multinet (Assets) Pty Ltd, Westar (Gas) Pty Ltd & Westar (Assets) Pty Ltd, Stratus (Gas) Pty Ltd & Stratus Networks (Assets) Pty Ltd, Draft Decision, p 65.

gas transmission assets that motivate a longer-term efficient level of investment in gas transmission assets. There is a disincentive upon investment of adjusting values after the event.[43] This may necessitate a treatment of past investment in a similar manner as for new capital investment, that is, valuation of the Initial Capital Base on the basis of historical costs. A DORC value might also meet this criterion, which is consistent with submissions made to me from Users, indicating that a value of the Initial Capital Base substantially in excess of a DORC value will lead to economically inefficient utilisation of gas resources by increasing the delivered cost of gas to economically inefficient levels, and inefficient use of energy sources generally due to inefficient fuel mixes being used for electricity generation and other energy requirements of industry.

182. Section 8.10(i) of the Code requires that in establishing the Initial Capital Base for a Pipeline consideration be given to the comparability of the cost structure of new pipelines that may compete with the Pipeline in question (for example, a Pipeline that may by-pass some or all of the Pipeline in question).

183. In my Draft Decision, I interpreted section 8.10(i) as a principle that the Initial Capital Base should not be so high as to result in Reference Tariffs that motivate inefficient provision of transmission assets, that is, greater than the minimum or efficient capital costs necessary to provide the transmission services. I took the view that an upper bound on the Initial Capital Base of a "new-entrant" DORC value is consistent with avoiding incentives for inefficient duplication of the existing assets. I also noted that, in practice, Capital Base values well in excess of DORC could potentially be established without motivating inefficient duplication of assets, for reasons that a new entrant would be faced with capital costs of Optimised Replacement Cost rather than DORC to replicate the service potential of the incumbent's assets and there are barriers to entry to the market other than capital costs, including costs that would be incurred in securing a sufficiently large market for gas transmission to warrant the construction of the assets.[44]

184. In submissions made to me, some Users of the DBNGP have put forward the view that section 8.10(i) would favour a DORC valuation of the Initial Capital Base. I do not accept that view. For the reasons given in the preceding paragraph, I consider that section 8.10(i) is not as limiting as this.

185. Section 8.10(j) of the Code requires that, in establishing the Initial Capital Base for a pipeline, consideration be given to the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase.

186. The Court provided substantial direction to me in regard to considerations under section 8.10(j), and in particular to consideration of the price paid by Epic Energy for the DBNGP in respect of section 8.10(j) and also sections 8.10(c) and (d):[45]

---

[43] *Re AGL Cooper Basin Natural Gas Supply Arrangements* (1997) ATPR 41-593 at 44, 215-220.

[44] Johnstone, D., 1999. Comments on Tobin's q and the Supposed Economic Justification for Replacement Cost (DORC) Regulatory Asset Valuation: Report to the Energy Markets Reform Forum (submission to the ACCC from the Energy Markets Reform Forum, 6 September 1999).

[45] [2002] WASCA 231 para 171–173.

> 171 Section 8.10(j) requires consideration of the price paid for any asset "recently purchased" by the service provider and the circumstances of that purchase. Given the precise context of the operation of s 8.10, which is the establishment of the initial Capital Base for a pipeline that was in existence at the commencement of the Code, and the time-lines appropriate to the service life of natural gas pipelines, it was, in my view, open to the Regulator to regard (as he did) the purchase of the DBNGP in March 1998 as one which was made "recently", within the meaning of this provision. It was further submitted for Alinta that this provision should not be construed to apply to the purchase of a complete pipeline but merely to some particular component of a pipeline system. For the purposes of the Gas Pipelines Access Law, which includes the Code (see the Act, s 3(1)), "asset" is defined to mean "any legal or equitable estate or interest" in property of any description. This would extend to the ownership of a complete pipeline. There is no reason apparent from the language, or the context, for limiting the scope of s 8.10(j) in the way contended. The Regulator did not regard it as so limited and considered the purchase of the DBNGP by Epic under this provision. I am not persuaded that there was any error in law in this respect.
>
> 172 What must be considered is the price paid, ie, in this case \$2.407 billion, and also, and significantly, the circumstances of this purchase. The latter consideration is amply wide enough, in my view, to allow an examination of the price paid according to the standards of reasonable commercial judgement as to value, the examination of the extent to which that price might have been influenced by considerations such as the prospect of monopoly profits and, although it is not the present case, the careful scrutiny of transactions between related entities or transactions which may involve motivations unrelated to value which might affect the price paid. With respect to the present case, clearly the nature and conditions of the tender process by which the State sold and Epic purchased the DBNGP would be circumstances which might properly be considered under 8.10(j). I should make it clear that I am not intending by these comments to make any exhaustive analysis of potentially relevant circumstances.
>
> 173 It is to be observed, however, that in a case such as the present where the purchase price is also advanced as reflecting the market valuation of the pipeline for the purposes of s 8.10(c), factors of the type that have been identified as relevant to the circumstances of purchase for the purposes of (j), would equally be relevant to the application of (c) and (d) to that market valuation.

187. The Court determined that consideration in my Draft Decision of the price paid by Epic Energy for the DBNGP was affected by errors of law.[46] The Court also gave direction as to what steps I should take in further considering the purchase price – as cited above in paragraph 172 of the Court Decision, and in paragraphs 188 to 190 of the Court Decision, as follows:

> 188 There is a further and different question whether the price paid by Epic for the DBNGP represented a sound commercial assessment of the value of the pipeline in the circumstances that prevailed at the time of the purchase and which were then reasonably anticipated, or reflected the reasonable expectations of Epic under the regulatory regime that applied to the DBNGP prior to the commencement of the Code.
>
> 189 The mere fact that it was a price paid at public tender is not necessarily determinative of any of these issues. Quite obviously, Epic may have erred in its assessment of value or had unreasonable expectations. It may have had reason to pay higher than true market value. Despite what has been urged on us, these are not matters for this Court to attempt to evaluate or to decide. It is for Epic to seek to justify to the Regulator that the price it paid represented market value at the relevant time and to establish its reasonable expectations under the previous regulatory regime. In this regard it is fair to say that the manner in which Epic sought to demonstrate that it paid market value for the DBNGP has shown itself, in the course of these proceedings, and in the Regulator's draft decision, to be well capable of being misunderstood in more than one material respect, namely the financial provision for future

[46] [2002] WASCA 231 para 205, 209.

> expansion of the capacity of the pipeline, and the period over which it proposed it should recover its capital investment. That will be for Epic to seek to remedy, if it is so minded.
>
> 190 It should also be said that the Regulator's further consideration of the price paid by Epic for the DBNGP will no doubt be undertaken with a different appreciation from that revealed in the draft decision of the meaning and effect of s 2.24 and the scope of its potential operation in s 8.1, and of the meaning and operation of s 8.1, s 8.10 and s 8.11, and their interrelationship. This will enable the purchase price paid by Epic to be viewed in a fresh light. Whether this will lead to any different outcome is a matter for Epic's further submission, if any, and the Regulator's re-assessment and decision.

188. Subsequent to issue of my Draft Decision and the Court Decision I have given considerable attention to the process of the sale of the DBNGP ("**Sale Process**") and to the price paid by Epic Energy.

189. I turn first to the Sale Process.

190. Epic Energy contends that the nature and conduct of the Sale Process for the pipeline gave rise to understandings and expectations on the part of Epic Energy in relation to, *inter alia*, the future transmission tariffs that would apply to the DBNGP, the linkage between the future tariffs and the purchase price, and undertakings by Epic Energy to expand the pipeline.[47] Epic Energy also contends that the nature of the Sale Process resulted in the purchase price of the DBNGP reflecting a "reasonable market value", and that the Sale Process provides justification for Epic Energy's Reference Tariff and Reference Tariff Policy to make provision for Epic Energy to obtain a return on and of the investment represented by Epic Energy's costs of purchasing the DBNGP.[48] I will address these contentions later in these reasons. I make note of them at this stage to establish the context for my consideration of the Sale Process.

191. In July 1996, the Western Australian Government established the Gas Pipeline Sale Steering Committee ("**GPSSC**") to make recommendations to the Government on the sale of the DBNGP, and subsequently to administer the process of the sale. The GPSSC recommended to the Government, and the Government subsequently approved, a four-phase sale process:[49]

- the preliminary phase (August 1996 to November 1996), involving invitation for parties to register interest in the purchase of the DBNGP, preparation of the asset for sale and the compilation of the sale marketing documents (the Information Memorandum[50]);

- the preparation phase (December 1996 to September 1997), involving the provision of the Information Memorandum to potential bidders that signed a confidentiality deed for that purpose;

---

[47] Dampier to Bunbury Natural Gas Pipeline Proposed Access Arrangement under the National Access Code Additional Paper 4: Regulatory Compact 8 September 2000.

[48] Epic Energy (WA) Transmission Pty Ltd 11 December 2002 Submission CDS#2: section 4.

[49] Dampier to Bunbury Natural Gas Pipeline Sale Steering Committee, May 1998. *Report on the Sale of the Dampier to Bunbury Natural Gas Pipeline*, Government of Western Australia.

[50] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum.

- submission to the GPSSC of non-binding bids for pre-selection (October 1997), involving the promotion of the transaction to potential bidders, the submission by bidders of non-binding bids, and the short-listing of bidders to participate in the final bid phase; and

- due diligence and binding bids (December 1997 to March 1998), involving due diligence assessments by the bidders and the seller, provision of bidders with a draft sale agreement, lodgement of binding bids, selection of the successful bidder and sale completion.

192. Initial registrations of interest in acquiring the DBNGP were submitted by 40 parties. Non-binding bids were submitted by seven parties, of which five were short-listed. Three parties subsequently submitted binding bids. Each of these parties submitted one bid complying with the draft sale agreement and at least one "non-complying" bid.

193. The assessment of binding bids was conducted by the GPSSC over three days from the closing date for submission of bids at mid-day on 28 February 1998 to 2 March 1998. A public announcement was made of the success of Epic Energy's bid on 3 March 1998.[51]

194. Prior to the sale of the DBNGP, the Western Australian Government had committed to adopt a regulatory regime for gas pipelines consistent with the National Access Code (subsequently the Code) from 1 January 2000, under which transmission tariffs for the DBNGP would be regulated. The Minister for Energy had also determined, as a separate matter that, in a transitional period between the sale of the DBNGP and introduction of the Code, the transmission tariffs for the DBNGP would be reduced to a target of "about $1.00" by 1 January 2000.

195. The GPSSC considered a range of options in regard to providing direction to bidders on tariffs that may apply during the transitional period and subsequent to introduction of the Code. The GPSSC determined to establish a transitional tariff regime that would see the establishment of tariffs by regulation until 1 January 2000. Tariffs subsequent to 1 January 2000 would be determined under the Code without any ongoing intervention by the Government.

196. In July 1997, the GPSSC issued an invitation to register interest for purchase of the DBNGP. The invitation document included a brief description of the existing and proposed regulatory regime. In regard to the proposed regime, the invitation document stated the following in respect of future regulation of tariffs.

> As a principal element of the process for sale of the DBNGP, the State is reforming the regulatory regime which governs operation of the DBNGP. It is intended that a new negotiation based regime that is consistent with the National Third Party Access Code for Natural Gas Pipeline Systems, currently being developed by Australia's Commonwealth and State Governments, will apply to the DBNGP after a transition period of around two years.
>
> It is intended that the [*Gas Transmission Regulations 1994*] will be substantially amended prior to the sale of the DBNGP Assets to allow the new owner and new and existing customers to negotiate

[51] Government of Western Australia Prior Government Media Statement, Ministerial Media Statement, Premier of Western Australia, 3 March 1998.

the pricing and other terms of service during the transition period. The Minister for Energy has announced that over the two year period prior to the introduction of the Access Code on 1 January 2000, the State expects tariffs on the DBNGP to reduce from current levels of around A$1.25 per gigajoule (GJ) of full haul, firm capacity to around A$1.00/GJ at 100% load factor.[52]

197. On 8 September 1997, the GPSSC released to potential bidders for the DBNGP the Information Memorandum on the DBNGP and details of criteria against which bids for the DBNGP would be assessed. Chapter 9 of the Information Memorandum described the existing and proposed future regulation of the pipeline system, including regulation governing third party access and governing general energy policy and safety.

198. The regulation of third party access and pricing was described in terms of the "existing access regime", a "transitional access regime" and the "access code", as follows.[53]

> … the third party access and pricing regime is found at present in Part 6 and Schedule 5 to the Gas Corporation Act 1994 (WA) ("GCA"), and in the [Gas Transmission Regulations 1994 (WA) ("GTR")] and the Gas Referee Regulations 1995 (WA) ("GRR"). The GCA, GTR and GRR (collectively the "Existing Access Regime") were developed to create a binding obligation on AlintaGas to provide third party access to the DBNGP's transmission services, and to clearly prescribe the terms, conditions and pricing objectives for that access. However, many of the provisions of the Existing Access Regime reflect AlintaGas' ownership of the DBNGP as a State owned entity. As a result, the process for the DBNGP Sale will be accompanied by the development of new DBNGP regulation which is appropriate for private ownership as well as being consistent with the National Third Party Access Code for Natural Gas Pipeline Systems ("NAC") currently being developed by the Commonwealth and the State and Territory Governments.
>
> Development of the new third party access and pricing regulation for the DBNGP will involve a Transitional Access Regime, and a completely new regime to be introduced approximately two years after the intended completion date of the DBNGP Sale. The State intends to adopt a new regulatory framework ("Access Code") for negotiated third party access to DBNGP transmission services, targeted to commence on 1 January 2000. The access Code will be consistent with the NAC. Over the period between 1 January 1998 and 31 December 1999 ("Transition Period"), the Acquirer will be required to develop a new access and pricing arrangement ("Access Arrangement") for the DBNGP within the requirements of the proposed Access Code.
>
> The State intends to restructure the Existing Access Regime prior to the DBNGP Sale to create the Transitional Access Regime which will govern the DBNGP during the Transition Period.

199. The Government indicated in the Information Memorandum that it envisaged a reduction in transmission tariffs under the transitional access regime and the access code:[54]

> The Government has announced its intention for there to be a declining tariff cap from 1 January 1998 to the year 2000. The intended mechanism for introducing this tariff cap is to introduce a Transitional Access regime which will incorporate the declining tariff cap and will be followed by

[52] The term "load factor" is understood to have been used in the "Invitation to Register Interest" to mean the ratio (expressed as a percentage) of the actual quantity of gas transported on behalf of a User in a given time period to that User's contracted maximum quantity for the same time period. The same meaning is given to this term throughout this Final Decision.

[53] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, p 95.

[54] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, pp 98,99.

the introduction on 1 January 2000 of a new regime under the Access Code. It is intended that this reform will be implemented in five principal steps as follows:

- development of the Transitional Access Regime to regulate the DBNGP throughout the Transition Period;
- during the period from 1 January 1998 until 31 December 1999 maximum tariffs will decline from the current level of approximately $1.26/Gj to estimated levels for 1998 and 1999 of approximately $1.24/Gj and approximately $1.12/Gj respectively for full haul T1 Service at 100% load factor;
- development of the Access Code which will be consistent with the NAC;
- development by the Acquirer of a DBNGP Access Arrangement in accordance with the Access Code framework. It is anticipated that transitional provisions for the Access Code will enable the processes of development, and of consideration and, if appropriate, approval by the responsible regulatory body of a DBNGP Access Arrangement, to occur during the Transition period; and
- commencement of the Access Code and DBNGP Access Arrangement on 1 January 2000.

200. The Information Memorandum also described how Reference Tariffs would be determined under the access code and provided estimates of the regulatory asset value and a full-haul Reference Tariff that may be determined under the Code:[55]

> Under the draft NAC, the pipeline operator must calculate Reference Tariffs in accordance with detailed principles relating to matters, including asset valuation, apportionment of costs, depreciation and incentive mechanisms. The Regulator has considerable discretion in determining whether to approve a Reference Tariff. The Regulator under the Access Code will have similar powers as regards the setting of Reference Tariffs.
>
> …
>
> Reference Tariff levels for transmission services to be provided by the DBNGP following the Transition Period will be based upon the Access Code principles, which will provide for a reasonable rate of return on the capital base of the pipeline's various assets. The GPSSC has, for its own purposes, commissioned an independent, indicative valuation ("Indicative Valuation") for the DBNGP Assets, consistent with NAC principles, for the purpose of considering possible future tariff paths for the services provided by the DBNGP. The Indicative Valuation suggests that a supportable capital base for the DBNGP Assets, being an Optimised Depreciated Replacement Cost ("ODRC") base consistent with the NAC principles, would be in the order of A$1,124 million as at 31 December 1997, although it should be noted that other bases of calculating the ODRC could give different values. The adoption of the ODRC as the most appropriate valuation methodology, having regard to the Reference Tariff principles in the Draft NAC, followed consideration of the Depreciated Historical Cost ("DHC") data.
>
> The GPSSC has also commissioned a detailed analysis to estimate the expected level of Reference Tariffs for a Reference Service that would be approximately equivalent to the full haul T1 service at 100% load factor currently offered on the DBNGP under the GTR, and which would be available to new and existing users of the DBNGP from 1 January 2000 when the Access Code is intended to be introduced ("Indicative Global Reference Tariff" or "IGRT"). The Indicative Global Reference Tariff has been calculated on the assumption that all loads are full haul. To the extent that a small proportion of the DBNGP loads are presently part haul, the Indicative Global Reference Tariff underestimates marginally a specifically calculated full haul T1 service at 100% load factor.

[55] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, pp 106,107.

> The IGRT analysis has involved a range of assumptions, including such matters as the manner in which tariffs would be escalated over time. However, the Access Arrangement may utilise differing assumptions in respect of such matters which could also be acceptable to the Regulator.
>
> The IGRT analysis has been based on the Indicative Valuation and a rate of return consistent with the proposed requirements of the draft NAC. The IGRT analysis has considered a number of possible price paths that would support a tariff on a price capping basis of $1.00/Gj, nominal at 1 January 2000. It is the Government's expectation that the tariff will be of that order at that time.

201. The Information Memorandum contained two qualifications on the estimate of the Reference Tariff that may apply under the Code:[56]

> The IGRT assumes only one full haul service is provided to Shippers and does not adjust for provision of part haul, back haul, interruptible and other services which may involve differing cost assumptions and which may, therefore, involve differences in proportional tariff levels given the expected requirements for cost reflective pricing under the Access Code. In addition, no adjustments have been made in estimating the IGRT for the economic effects of existing contractual obligations, such as the Alcoa Agreement, which the Acquirer will be required to assume as part of the DBNGP Sale. The cost reflective analysis which the Acquirer will need to undertake in developing the Access Arrangement will need to incorporate such adjustments and would be expected to result in a range of reference tariffs which may differ from the IGRT estimated above.

202. The study undertaken for the Government to estimate a Reference Tariff that may be approved for the DBNGP under the Code was documented in considerable detail, including a detailed description of a methodology by which a Reference Tariff would most likely be determined under the Code and indicated a range of tariff values that may be possible, depending upon assumptions such as asset valuation and cost parameters for the pipeline business, as well as the future tariff path. While the GPSSC elected to publicise in the Information Memorandum only a single tariff value of $1.00/GJ as an estimate of the tariff that may be approved for a full-haul service under the Code (with no description of the calculations undertaken in deriving the estimated tariff or the critical assumptions underlying the tariff estimate), bidders progressing to the final bid stage were provided with access to the study report and the details of calculations used to derive the estimated tariff.

203. The Information Memorandum also included a disclaimer in respect of the estimate of the future Reference Tariff:[57]

> The Indicative Valuation and the IGRT give an indication of what the Regulator may consider to be an appropriate asset valuation and notional global tariff, respectively, under the Access Code. The GPSSC makes no representation that the Indicative Valuation and the IGRT will have any standing, weight or force in respect of the considerations of, or would be approved by, a Regulator.

204. The information on the future regulatory framework for the DBNGP provided in the Information Memorandum was consistent with the Western Australian Government's obligations under the Natural Gas Pipelines Access Agreement, signed by heads of Australian Governments on 7 November 1997. Under this agreement, the Western Australian Government agreed to enact the Gas Pipelines Access Law (incorporating the Code) as a law of Western Australia. Any exception or exemption of a gas

[56] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, pp 107, 108.

[57] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, p 108.

pipeline system from regulation under the Gas Pipelines Access Law required the grant of a derogation under the *Natural Gas Pipelines Access Agreement*. While derogations were granted for the DBNGP in respect of the timing of application of the Law, there was no derogation made in respect of ultimate regulation. The signing of the Natural Gas Pipelines Access Agreement on 7 November 1997 also committed the Western Australian Government to adoption legislation having an essentially identical effect to the Gas Pipelines Access Law (including the Code). Under the terms of the agreement, Western Australia could not adopt any other version of the Code without the agreement of all other signatory governments.[58]

205. The intent of the Government in respect of future regulation of third-party access to the DBNGP was publicly stated in media releases from the Minister for Energy in September 1997[59] at the time the Information Memorandum was released and in November 1997[60] when the proposed legislation for sale of the DBNGP was introduced in Parliament.

206. Despite the indications in the Information Memorandum that there would be a regulated tariff introduced under the transitional access regime, and that tariffs after 1 January 2000 would be established under the Code, prospective bidders for the pipeline were required to set out proposed tariff paths.

207. Bidders were required to provide details of proposed tariff paths as a component of schedules to the Asset Sale Agreement, which had to be completed by each bidder as part of a final bid. Clause 9 of Schedule 5 to the Asset Sale Agreement stated:[61]

> The Final Bid Information contains details of the tariff rates for gas transmission and tariff path which the Buyer has indicated to the Seller it proposes to apply in the conduct of the business of the DBNGP Assets:
>
> (a) which, based upon all information available to the Buyer, reflect tariffs for gas transmission that will provide the Buyer with an acceptable return on investment; and
>
> (b) which, the Seller may (and the Buyer irrevocably authorises the Seller to) freely disclose to any Governmental Agency or generally in the course of any public enquiry or other determination process relating to tariff rates for gas transmission.

208. During the months of January and February 1998 and leading up to the submission of binding bids for the DBNGP, meetings were held between some members of the GPSSC, advisors to the GPSSC and representatives from bidding parties. I have not been able to locate any minutes of these meetings.

209. Epic Energy contends that it discussed the matter of future tariff paths with members of the GPSSC at these meetings, and was directed to base its bid on a presumption of a tariff at and after 2000 of $1.00/GJ.[62]

---

[58] Natural Gas Pipelines Access Agreement, 7 November 1997, clause 5.3.

[59] Government of Western Australia Prior Government Media Statement, Ministerial Media Statement, Minister for Energy, 7 September 1997.

[60] Government of Western Australia Prior Government Media Statement, Ministerial Media Statement, Minister for Energy, 11 November 1997.

[61] Quoted by Epic Energy in the Access Arrangement Information, 28 July 2000, p24.

[62] Epic Energy (WA) Transmission Pty Ltd, 12 May 2000, Submission 4, The Regulatory Compact.

210. Epic Energy has indicated in a submission to me that representatives from Epic Energy met with GPSSC members and advisors to the GPSSC a few weeks prior to the closing date for final bids. Epic Energy states that at that meeting, a representative from Epic Energy stated that he believed, given statements from the Government, that the State may be interested in a tariff lower than $1.00, and that a lower tariff would have a lower purchase price associated with it. According to Epic Energy's submissions, a member of the GPSSC and one of the GPSSC's advisors stated that Epic Energy should "solve" its purchase price based on a tariff of $1.00, although another member of the GPSSC indicated to Epic Energy (possibly at a different and later meeting) that as the future regulatory regime and criteria are not yet established, Epic must take a view on what the future regime will determine as a reasonable tariff, and it is Epic Energy's risk and something that Epic Energy and other bidders will have to take a view on.

211. In a further submission to me, Epic Energy indicated that at meetings between Epic and the GPSSC, Epic Energy questioned the GPSSC as to whether Epic Energy should make its bid conditional on the $1.00/GJ tariff. Epic Energy says that in response it was told by a member of the GPSSC "no … as the Government would do the right thing".[63]

212. Although I invited a relevant member of the GPSSC and an advisor to the GPSSC to comment on the statements attributed to them by Epic Energy, I have not received any evidence that contradicts the statements Epic Energy says were made.

213. Final bids for the pipeline were received by the GPSSC on Saturday 28 February 1998.

214. On the basis of confidential information obtained by me, it is apparent that Epic Energy's proposed tariff path subsequent to 1 January 2000 was considered of secondary importance in the selection of Epic Energy's complying bid as the preferred bid for the reason that, regardless of the proposed tariff path, the owner of the pipeline would be subject to a regulatory regime consistent with the National Access Code.

215. I have examined the written disclaimers and warranties that form part of the information provided to bidders and of the sale agreement, which are consistent with the position that there was no commitment by the Government as to tariffs beyond 1 January 2000. These disclaimers and warranties are consistent with the statement in the report on the sale of the DBNGP that:[64]

> Epic Energy committed to lower gas tariffs through the transitional access regime where tariffs will fall from $1.19 nominal in 1998 to $1.00 nominal in 2000. From the year 2000 the National Access Code is to be adopted.

[63] Epic Energy (WA) Transmission Pty Ltd, 30 November 2001, Additional Information DD5: Additional Information on DBNGP Sale Process.

[64] Minister for Energy, May 1998, *Submission to Parliament: Report on the Sale of the Dampier to Bunbury Natural Gas Pipeline*.

216. Several statements made by the Government immediately subsequent to the selection of Epic Energy as the preferred bidder are consistent in indicating that tariffs after 1 January 2000 after which the National Access Code would apply.[65]

217. Future regulation of transmission tariffs was a matter given substantial consideration by the GPSSC and was addressed in documentation provided to potential bidders for the pipeline. The documented information provided by the Government to potential bidders for the pipeline is consistent and unambiguous in statements as to future regulation of third-party access to the DBNGP, including regulation of tariffs, indicating that:

- the Government intended to specify a transitional access regime to the year 2000 whereby the transmission tariff would be reduced, by government regulation under a transitional access regime, from the tariff of $1.27/GJ in 1997 to $1.24/GJ for 1998 and $1.12/GJ for 1999;

- the Government intended to introduce the National Third Party Access Code for Natural Gas Pipeline Systems, under which an Access Arrangement for the pipeline would be required to be submitted for approval by an independent regulator, and Reference Tariffs (as well as other elements of the Access Arrangement) would be subject to the approval of an independent regulator;

- the Government expected an Access Arrangement for the DBNGP to be effective as of 1 January 2000, and that this Access Arrangement would include a Reference Tariff for a full-haul service; and

- by virtue of the envisaged independence of the Regulator under the Code, the Government was unable to make a definitive statement as to the value of regulated transmission tariffs after 1 January 2000, although the Government did indicate that a Reference Tariff at 100% load factor of about $1.00/GJ was expected for a Reference Service that would be approximately equivalent to the full haul T1 Service.

218. Despite the indication of the Government's position on future tariffs set out above, statements made during the Sale Process as to tariffs suggest to me that a reasonable person making a bid for the pipeline could have attached some weight to a prospect of a headline full-haul transmission tariff of $1.00 per GJ as an approved regulated tariff under the Code as of 1 January 2000, and a tariff path subsequent to 1 January 2000 based on escalation of the $1.00 tariff.

219. Having provided this description of the Sale Process, I move now to an examination of Epic Energy's purchase price for the DBNGP.

[65] Government of Western Australia Prior Government Media Statement, Ministerial Media Statement, Premier of Western Australia, 3 March 1998. Hon Colin Barnett, MLA Minister for Energy, Brief Ministerial Statement 10 March 1998 Sale of the Dampier to Bunbury Natural Gas Pipeline. Hon Colin Barnett, MLA Minister for Energy, Sale of the Dampier to Bunbury Natural Gas Pipeline, Statement by Minister for Energy, Hansard, Legislative Assembly 10 March 1998, pp 138,139. Hon Colin Barnett, MLA Minister for Energy, in response to question from Hon. J Grill, Hansard, Legislative Assembly 10 March 1998, pp 333, 334.

220. In March 1998, Epic Energy paid $2,407 million for the DBNGP. Epic Energy has also indicated that it incurred costs of $42.49 million of associated acquisition costs,[66] giving a total cost of purchase of $2,449.49 million.

221. In addition to the nature and conditions of the tender process by which the State sold the DBNGP, the Court found that the requirement under section 8.10(j) to consider the circumstances of the purchase includes consideration of whether the purchase price represented a reasonable commercial judgment as to the value of the DBNGP and an examination of the extent to which the price might have been influenced by considerations such as the prospect of monopoly profits.[67]

222. In assessing whether the sale price represented a reasonable commercial judgment as to the value of the DBNGP, I have considered whether Epic Energy erred in its assessment of value or had unreasonable expectations at the time of the purchase.

223. I have examined the purchase price on the basis of information made available to me by Epic Energy, parent companies of Epic Energy and Epic Energy's financiers. Despite its obvious relevance (from the terms of the Code, the decision by the Court and the inquiries made by me of Epic Energy), Epic Energy has informed me that no substantive documentation evidencing the business case in relation to the bid was put before the board of any Epic Energy companies because the entities set up to purchase the DBNGP were only incorporated immediately prior to the final bid being made.

224. In a submission made to me, Epic Energy has stated that a mathematical model was developed by a key strategic adviser for Epic Energy and Epic Energy's owners in relation to Epic Energy's bid for the DBNGP, and that this model derived the expected value of the investment and hence supported the purchase price.[68] Epic Energy has provided me with the following original sources of information regarding the mathematical model ("**Acquisition Model**") and the assumptions that were applied to the model.

- Three spreadsheet (Excel) models (regulatory model v13 (final).xls; revenue model v13 (final).xls and financial model v13 (final).xls) and a print out of those models (marked as printed on 1 June 1998). These models are referred to collectively as Version 13 of the Acquisition Model.

- A print-out of earlier versions of the above models (marked as printed on 26 February 1998), referred to as Version 12B of the Acquisition Model. This version of the model was audited by a financial advisor to Epic Energy. An electronic version of this model was not provided.

- A report from Epic Energy's key strategic advisor entitled *Epic Energy Bid for the Dampier to Bunbury Natural Gas Pipeline: Databook of Assumptions Contained in the Financial Model Base Case 13 (Final)*, dated 25 March 1998.

---

[66] Indicated by Epic Energy to include borrowing expenses and other costs associated with the acquisition, and net adjustments for spares, linepack and construction work in progress (Epic Energy response to OffGAR Information Request 6, section 3.2).

[67] [2002] WASCA 231 para 172.

[68] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#3, para.6.15.

- A report from Epic Energy's key strategic advisor entitled *Epic Energy Pty Limited Potential Acquisition of the Dampier to Bunbury Natural Gas Pipeline: Development of Future Tariffs*, dated 14 January 1998.

- A report from a financial advisor to Epic Energy entitled *Dampier to Bunbury Gas Pipeline: Review of the Financial Model – Equity*, dated 27 February 1998.

225. Epic Energy has submitted to me that even though the final version of the Acquisition Model (Version 13) post-dates the lodgement of Epic Energy's final bid, this model sets out the actual basis on which the purchase price was derived.

226. Epic Energy has also provided me with copies of reports on due diligence studies conducted prior to submission of its final bid, copies of some materials provided to boards of the parent companies of Epic Energy in respect of decisions related to purchase of the DBNGP, and minutes of some board meetings at which the purchase of the DBNGP was considered.

227. Examination of this information allows insight into how Epic Energy determined the value of its final bid and matters that were considered by Epic Energy and/or its advisors in deriving the value of the final bid. The information also indicates forecast financial out-workings of the purchase price. It is evident from this information that Epic Energy was aware of the explicit and implicit assumptions underlying the bid value, and the potential financial out-workings of a purchase price equal to the bid.

228. The basis of assumptions made by Epic Energy's advisors about the proposed future tariffs for the period after 1 January 2000 is not clear from the Acquisition Model or from related information. The information provided by Epic Energy would suggest that Epic Energy made assumptions as to future tariffs by:

- determining the tariffs that would deliver a revenue stream equal to its calculated annual "cost-of-service", reflecting its assumptions about the position on matters including the cost of capital, depreciation and asset value that could be defended before a regulator under the Code; and

- assuming that it would be able to charge tariffs that were higher than tariffs set precisely at its calculated annual cost of service (or, more precisely, tariffs that would decline at a lower rate in real terms than would be implied by its calculated annual cost-of-service).[69]

229. Epic Energy has indicated to me that the tariffs assumed for the period after 1 January 2000 (and indicated in schedule 39 of the Sale Agreement) were influenced by the

[69] The depreciation schedule is the mechanism through which different time paths for regulated tariffs can be delivered, *while holding the value of the revenue stream constant*. A depreciation schedule that defers the recovery of capital – such as annuity depreciation – will imply *lower* tariffs initially compared to a depreciation schedule that results in an earlier return of capital (like straight-line depreciation), but *higher* prices in the future (compared to straight-line depreciation). The reduction in revenue initially under annuity depreciation (compared to straight-line depreciation) is offset by higher revenue in later years (compared to straight-line depreciation) – with the result that both depreciation schedules deliver the same present value of revenue (when calculated using a consistent discount rate), with only the time path of tariffs affected. The evidence suggests that Epic Energy selected a depreciation schedule (annuity) to produce a price for 2000 that was consistent with the Government's expectations.

Government's desire for a tariff of $1.00/GJ in 2000 and the Government's expectations that this tariff would be supportable under the Code. However, the future tariffs proposed by Epic Energy in schedule 39 of the Sale Agreement were different to the tariff of $1.00/GJ expected by the Government. It is evident from the Government's Information Memorandum that the $1.00/GJ indicated as expected by the Government comprised a tariff for full-haul gas transmission under the T1 Service established by the *Gas Transmission Regulations 1994*.[70] The tariffs proposed by Epic Energy in schedule 39 of the Sale Agreement comprised a combination of tariffs of $1.00/GJ for gas delivery to Perth and $1.08/GJ for Delivery Points downstream of Kwinana Junction. The tariffs proposed by Epic Energy also comprised a different tariff structure than existed for the T1 Service, resulting in the proposed tariff of $1.00/GJ for gas delivery to Perth being, in practical effect, a tariff in excess of the $1.00/GJ that the Government indicated as expected in a situation where gas is transmitted for a User at less than 100 percent load factor.[71] The information provided to me does not indicate how Epic Energy derived the tariffs that it proposed in schedule 39 of the Sale Agreement.

230. Epic Energy has further indicated to me that, for the reason that it calculated its purchase price on the basis of tariffs other than those determined by its regulatory model forming part of its Acquisition Model, and that the regulatory sub-model of the Acquisition Model was developed only to provide some comfort to owners that the tariff used by Epic Energy for its bid was supportable under the Code. For these reasons Epic Energy says the regulatory model played only a minor role in the development of the purchase price.

231. If Epic Energy did develop its purchase price without significant regard to the methodology that might be adopted under the Code, even though it had obtained expert advice concerning that methodology, then I am of the view there is a real issue as to the prudence of the approach adopted by Epic Energy in formulating its bid.

232. Despite Epic Energy having indicated to me that the regulatory model played only a minor role in the development of Epic Energy's purchase price, the information provided to me indicates that management boards of Epic Energy's owners were advised that the expected tariffs for the DBNGP were based on, or supported by, tariffs derived by a cost-of-service calculation. On the evidence available to me, particularly the contemporaneous documentary evidence, I am unable to accept that management boards of Epic Energy's owners were informed that the forecast future tariffs were based on representations made by the GPSSC or Government as to the tariffs that may apply under the Code, rather than tariffs based on a cost-of-service

[70] Government of Western Australia, August 1997, Sale of the Dampier to Bunbury Natural Gas Pipeline, Information Memorandum, pp 106, 107.

[71] The tariff for the T1 Service put in place on 1 January 2000 by the *Gas Pipelines Access (Privatised DBNGP System) (Transitional) Regulations 1999* comprised a capacity reservation charge of $0.728029/GJ and a commodity charge of $0.271971/GJ, totalling $1.00 for gas delivery at 100 percent load factor. The tariff proposed by Epic Energy in Schedule 39 of the Sale Agreement (for delivery to Perth) comprised a fixed charges totalling $0.857/GJ and throughput-related charge of $0.148/GJ, also totalling approximately $1.00/GJ at 100 percent load factor. For both tariffs, the effective total tariff is in excess of $1.00 if load factor is less than 100 percent. The higher component of fixed charges in the proposed tariff for the Firm Service results in the effective per GJ tariff for the Firm Service being greater than for the T1 Service for the same load factor, where that load factor is less than 100 percent.

calculation. I am therefore unable to accept Epic Energy's contention that the regulatory sub-model and the cost-of-service tariffs calculated in this model played only a minor role in development of Epic Energy's purchase price.

233. While the information provided to me suggests that the Government's stated objective of a tariff of $1.00/GJ in 2000 affected the assumptions made by Epic Energy about the tariffs that would apply under the Code (even though Epic Energy assumed tariffs that were in excess of the stated expectation), I am not satisfied that the Government's stated objective in relation to tariffs affected the assumptions made by Epic Energy about the future regulator's view of the cost-of-service for the DBNGP over the life of the pipeline. Rather, the evidence suggests that Epic Energy and/or its advisors considered the assumptions about the main inputs to the life-time cost of service for the DBNGP – which are the Initial Capital Base and regulated rate of return on assets – to be capable of being supported before an independent regulator under the Code, and to be the basis of future regulated tariffs under the Code.

234. One key assumption of the cost-of-service calculation was that a regulator under the Code would set the Initial Capital Base of the DBNGP at a value of $1,100 million which was close to a DORC value of $1,124 million derived by Price Waterhouse for the GPSSC. It was considered that this value may be increased after further work to re-estimate a DORC value. Consideration was given to values of ±$100 million around the value of $1,100 million, but I am not satisfied that any values of the Initial Capital Base outside of this range, or other than a DORC value, were given material consideration in the estimation of the expected value of the pipeline or in determining a value of Epic Energy's final bid. This appears to me to be a reasonable assumption given the information available at the time. The only regulatory decision under the "Code" available at the time adopted a value for the relevant pipeline that was lower than that pipeline's DORC value.[72] However, the circumstances of the DBNGP (in particular, the fact that the use of a DORC value would not have lead to an increase in regulated tariffs) would have suggested that a DORC value could be approved as the regulatory value.

235. The second key assumption required to forecast future regulated tariffs is the rate of return (or cost of capital) that a future regulator would approve for the DBNGP's regulated activities (referred to below as the regulatory rate of return) for the purpose of approving regulated tariffs under an Access Arrangement.

236. An express assumption in the Acquisition Model was that the Regulator would approve a regulatory rate of return on assets equal to a real pre-tax weighted average cost of capital ("**WACC**") of 11.83 percent. The assumption of a real regulatory rate of return of 11 to 12 percent was indicated in due diligence reports and papers presented to management boards of the owners of Epic Energy.

237. My examination of the Acquisition Model indicates that the expected value of the DBNGP is very sensitive to the assumption of the regulatory rate of return, with a

---

[72] Independent Pricing and Regulatory Tribunal, July 1997, Determination on the Proposed Access Undertaking (As Varied) of AGL Gas Networks Limited. IPART made its decision under an interim NSW Gas Code. The provisions dealing with the Initial Capital Base and Rate of Return were materially the same as those ultimately forming part of the *National Third Party Access Code for Natural Gas Pipeline Systems*.

one-percentage point difference in the regulatory rate of return corresponding to an approximately $200 million difference in the expected value of the pipeline. Although Epic Energy has submitted that the corresponding difference in the expected value of the pipeline is not $200 million but $150 million, I am satisfied that my examination is correct. Whichever value is applied, given this sensitivity a reasonable bidder would have undertaken analysis to assess the probability of the regulatory rate of return being different to that assumed so that those risks could be reflected in the bid price.

238. There were a number of substantial downside risks associated with the assumed regulatory rate of return. These downside risks were capable of being identified, based upon information available at the time, by a prudent and objective assessment of a future independent regulator's likely position on the cost of capital. The assessment of the expected value of the DBNGP appears to have been deficient in not identifying these risks.

239. First, there were a number of risks in respect of the input values to the Capital Asset Pricing Model (used by Epic Energy's key strategic advisor to estimate the WACC) that should have been known to Epic Energy and/or its advisor at the time of the sale of the DBNGP, but which do not appear to have been given material consideration. These included the possibility that the future regulator under the Code would:

- ascribe value to franking credits;
- take account of the features of the tax law (in particular, accelerated depreciation) deriving an allowance for taxation (which is reflected implicitly in the regulatory WACC), or at least take account of changes in the statutory rate of taxation;
- revise the estimate of the WACC in accordance with changes in interest rates; and
- adopt an assumption about gearing of the regulated business that was consistent with observed practice.

240. Secondly, there appears to have been an incorrect interpretation of precedent information that provides some indication of a future independent regulator's likely position on the cost of capital.

241. A report from Epic Energy's key strategic advisor (prior to the final bid) refers to three "precedents" of regulatory rates of return that were available at the time of the sale of the DBNGP, which are WACC values labelled as "IPART AGL" of July 1997,[73] "VIC GTC" of November 1997[74] and "EIG DBNGP" of December 1997.[75]

242. The real pre-tax WACCs quoted in the report for these precedents were as follows:

[73] This is assumed to be a reference to: Independent Pricing and Regulatory Tribunal, Determination on the Proposed Access Undertaking (As Varied) of AGL Gas Networks Limited, July 1997.

[74] This is assumed to be a reference to: Victorian Government, Access Arrangement Information for Transmission Pipelines Australia, November 1997.

[75] Understood to be a reference to: AlintaGas Tranmission, 1997, Dampier to Bunbury Natural Gas Pipeline: Price Redetermination prepared in Accordance with Regulation 151 of the *Gas Transmission Regulations 1994*.

- IPART AGL – 11.63 percent;
- VIC GTC – 10.79 percent; and
- EIG DBNGP – 7.88 percent.

243. In reporting of the WACC estimates produced by IPART in its July 1997 determination and by the Victorian Government in its proposed Access Arrangement for Transmission Pipelines Australia in November 1997, Epic Energy's key strategic advisor introduced changes in the values of the CAPM parameters used in the WACC calculations of these other parties.

- The discussion of the IPART decision appeared to use the parameters that were used in its first draft determination, rather than those accepted in its second draft determination (May 1997) and its determination (July 1997). The most significant change between the first draft determination and the latter decisions was IPART's acceptance that franking credits have value. This resulted in the WACC value estimated by IPART being lower (at 10.26 percent) than cited by Epic Energy's key strategic advisor (11.63 percent).[76]
- The discussion of the Victorian Government proposal quotes a value attributed to franking credits, but the key strategic advisor used a value of zero in its own calculation of the Victorian Governments proposed WACC, resulting in the advisor deriving a different WACC value (10.79 percent) than the Victorian Government (at 9.73 percent). This is despite the Victorian Government's proposed real pre-tax WACC being clearly stated in its proposed Access Arrangement.[77]

244. In addition, a reasonable analysis of precedent WACC values requires comparison of WACC values on the basis of consistent assumptions as to market interest rates and inflation. Epic Energy recognised that tariffs would be re-set to take into account, *inter alia*, changes in inflation and real interest rates. The key strategic advisor made its own assumptions about market interest rates and inflation which were different to the assumptions of IPART and the Victorian Government. When revised to reflect the advisor's own assumptions for these parameters, the IPART and Victorian Government WACC estimates provide precedent estimates of real pre-tax WACC values of 8.82 percent and 8.62 percent, respectively.

245. These matters serve to highlight the risks associated with estimating a regulatory rate of return that might be approved by a future regulator and serve to emphasise that prudence requires due allowance to be made for these risks. I am not satisfied on the material available to me that any such allowance was made.

246. Thirdly, there does not appear to have been any comparison between the assumed regulatory rate of return of 11.83 percent that would be approved by the regulator, and

[76] Independent Pricing and Regulatory Tribunal, Determination on the Proposed Access Undertaking (As Varied) of AGL Gas Networks Limited, July 1997, pp.66, 119.

[77] Victorian Government, Access Arrangement Information for Transmission Pipelines Australia, November 1997, Table 2.5(e).

actual rate of return from the DBNGP, as implied by Epic Energy's bid for the pipeline. I have calculated that the Acquisition Model implies an internal rate of return on the investment (and hence assumed cost of capital) to Epic Energy on its purchase price of a certain percent[78] (real, pre-tax). Epic Energy has disputed the calculation made by me advising that the value is 7.2%. Whichever value is applied, there appears to have been no recognition of the risk associated with an assumption that a regulator would estimate the cost of capital for the DBNGP to be 11.83 percent, when the actual cost of capital to investors was assumed (when valuing the asset) to be substantially lower.

247. While there was some uncertainty at the time of the sale of the DBNGP as to the rate of return that a regulator may approve for regulatory purposes, it is my view that insufficient weight was given by Epic Energy, and/or its advisors, to the requirements of the Code that the regulator would approve a rate of return "which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service". It is also my view that insufficient weight was given to the risk, evident from information available at the time, that the rate of return approved by a regulator under the Code could be significantly lower than the assumed 11.83 percent.

248. The Acquisition Model suggests that the difference between the price paid for the DBNGP ($2,407 million) and the assumed regulatory value ($1,100 million) can in large part be explained by the assumption that a future regulator would approve a regulatory rate of return well in excess of the cost of capital implicitly assumed by the investors in the DBNGP assets.

249. It appears that the assumption of a regulatory rate of return of 11.83 percent was adopted from the January 1998 report of Epic Energy's key strategic advisor. The executive summary to the report states:

> While a 'revenue cap' tariff path is an appropriate methodology for calculating allowed returns on the asset base of a pipeline, it is (*sic*) does not necessarily represent the most appropriate tariff structure for inclusion in Epic's business plan or in its final bid document for the DBNGP. We note that Australian regulators favour a 'price cap' (CPI-linked) approach to regulation over the more traditional 'rate of return' and 'revenue cap' methodologies, and that the Code specifically provides for the adoption of a CPI minus "X" regulator approach. At this time we propose that Epic adopt a similar approach, however with a % of CPI methodology, to defining the tariff path in its Final Bid. The merits of this approach are that:
>
> - It would not reveal any information to possible future regulators as to assumed asset values, WACCs, etc. used in setting tariffs;
> - The [Profit and Loss] and Balance Sheet ratios used to support the tariff path would be based upon the actual purchase price and costs of Epic; and
> - It would establish the principle that the economic viability of Epic's DBNGP operation should be a key consideration of the regulator and in the regulatory process.

[78] My calculations are based upon a mathematical model provided to me in respect of which a claim for confidentiality has been made. Therefore the precise percentage figure appears in confidential Annexure A to my Final Decision.

250. It should have been evident to those reading the report that:

- the approach recommended in the report to specifying a tariff path appears to have been developed to make it difficult for the future regulator under the Code to obtain information used to determine the bid price;
- the regulatory rate of return that had been adopted in the report had been adopted on the basis that it would be possible to prevent the future regulator from obtaining the information that was used to determine the bid price;
- reliance was being placed upon a strategy of tying the bid price to the tariff of $1.00/GJ as the basis upon which to support that tariff in submissions to the Regulator.

251. In summary, the evidence of the Acquisition Model and the other information provided to me by Epic Energy and its owners shows that Epic Energy supported the value of its bid for the DBNGP, and hence the subsequent purchase price, taking account of a cost-of-service tariff that it considered would be supportable before a regulator under the Code. In these circumstances, I am not convinced that the value of Epic Energy's bid for the DBNGP was affected by any representations or statements by the Government as to the tariffs that may apply under the Code subsequent to 1 January 2000.

252. Notwithstanding this, advisors to Epic Energy recommended a strategy of linking the bid price to the tariff so as to create a basis for supporting the tariff of $1.00/GJ when an Access Arrangement came to be approved under the Code. This suggests that Epic Energy knew of the uncertainties that the Code might bring for future revision of the tariff. Yet, the bid price does not appear to have brought these uncertainties to account.

253. Having now considered the circumstances of the purchase, including the nature and conditions of the tender process by which the State sold and Epic Energy purchased the DBNGP, I now turn to two further matters that the Court has referred to in relation to the purchase price.[79]

254. Firstly, the Court referred to the price paid for the DBNGP according to standards of reasonable commercial judgment as to value. In this regard, the evidence before me suggests that the value of Epic Energy's bid for the DBNGP was very sensitive to an assumption made by Epic Energy's advisors as to the rate of return on assets that would be approved by a regulator for the purposes of approving a tariff under the Code. For the reasons set out above, I find that in deriving the expected value of the DBNGP and the purchase price, no proper consideration was given to substantial downside risk in the assumption made as to the rate of return that may be approved by a regulator. Therefore the price did not reflect reasonable commercial judgement. A prudent and objective assessment of a future independent regulator's likely position on the rate of return, based upon information available at the time, should have identified this risk and reflected this risk by assuming a lower regulatory rate of return

[79] [2002] WASCA 231, para 172

in assessing the value of the pipeline. As a consequence, the price paid for the pipeline by Epic Energy exceeded a reasonable market value for the asset.

255. Secondly, the Court has referred to the extent to which the price might have been influenced by considerations such as the prospect of monopoly profits. In this regard, the Acquisition Model suggests that the difference between the DORC value contemplated by Epic Energy and/or its advisors as the regulatory asset value for the DBNGP and the value of Epic Energy's final bid is largely explained by the assumptions that a regulator would approve a rate of return on assets substantially in excess of Epic Energy's actual cost of capital and that a regulator would approve tariffs in excess of its true cost-of-service tariffs. The expected value arising from these assumptions may be considered to comprise a value of monopoly profits that would be able to be captured by Epic Energy. That is, in assuming that a regulator would allow Epic Energy to charge a tariff based on a rate of return on assets well in excess of its own cost of capital, there was an assumption made that Epic Energy would be able to earn revenues in excess of costs (where those costs included a return on investment), consistent with a definition of monopoly profits.

256. The assumptions giving rise to the foreseen prospect of capturing monopoly profits were assumptions made by Epic Energy and, on the basis of evidence before me, did not reflect reasonable commercial judgment in so far as these assumptions did not take into account a substantial downside risk in the rate of return, and hence tariffs, that would be approved by a regulator. They were also assumptions made in circumstances where Epic Energy was aware that the provisions of the Code may result in the tariff being reduced.

257. The above consideration of the purchase price of the DBNGP was undertaken in relation to a requirement under section 8.10(j) of the Code, relating to the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase. I now consider section 8.10(k).

258. Section 8.10(k) of the Code requires that, in establishing the Initial Capital Base for a pipeline, consideration be given to any other factors that the Relevant Regulator considers relevant.

259. Since my Draft Decision a subsequent submission to me from a User of the DBNGP indicated that I should consider relevant, and consequently give weight as a fundamental element to, the Commonwealth and Western Australian Governments' policies and commitments with respect to limiting national and state greenhouse gas emissions, respectively, noting that the high tariffs that may result from valuation of the Initial Capital Base at the purchase price may cause a switch in fuel sources for electricity generation away from natural gas to other fuel sources, with a consequent increase in emissions of greenhouse gases. It is my view that this matter falls within the scope of the objectives of section 8.1 of the Code, especially as these objectives relate to the efficient pricing of gas transmission services and therefore of gas as an energy source. I do not consider that the matter warrants further consideration as a stand-alone issue.

260. In noting the submission concerning emissions of greenhouse gases, I conclude my consideration of the section 8.10 matters and move on to section 8.11 of the Code.

261. Section 8.11 of the Code provides that the Initial Capital base for Covered Pipelines that were in existence at the commencement of the Code normally should not fall outside the range of values determined under paragraphs (a) and (b) of section 8.10, being the DAC and DORC values respectively.

262. Epic Energy's proposed Initial Capital Base is greater than the estimated DAC and DORC values of the pipeline and thus outside of the range contemplated by section 8.11 of the Code.

263. In my Draft Decision, I indicated that there was no reason to value the Initial Capital Base outside of the range of values contemplated by section 8.11 of the Code, that is the range of values between DAC and DORC. In particular, I did not consider there to be any reason to value the Initial Capital Base in excess of a DORC value.

264. Users of the DBNGP have submitted that there is no basis to justify a value of the Initial Capital Base outside of the range contemplated by section 8.11.

265. The Court Decision addressed section 8.11 indicating that reasons for valuation of the Initial Capital Base outside the "normal" range contemplated by section 8.11 may arise as a result of the requirement to consider factors other than economic efficiency in determination of the Initial Capital Base,[80] including considerations under sections 8.10(c), (d), (g) and (j) of the Code. The Court emphasised that the acquisition of a pipeline on the open market before the commencement of the Code is a circumstance that may take the application of section 8.10 outside of what is normal within the meaning of section 8.11, because a sale at a market value may well involve the capitalisation of some monopoly returns, the recovery of which may be a legitimate business interest of the new purchaser.[81] On this point, the Court further indicated that:[82]

> 179 At least in cases where an investment in a pipeline before the Code applied is made in the course of an arm's-length commercial transaction, and is based on a sound commercial assessment of the value of the pipeline in the circumstances then prevailing and anticipated, it is not apparent from the terms of the Act and the Code that the intention is, automatically and necessarily, to preclude consideration of the investment, or the interests of the service provider in recovering it together with a reasonable return, or the reasonable expectations under the preceding regulatory regime of such a service provider. The interests of such a service provider may well be in tension with other considerations, but it is not apparent that their exclusion is intended by the Act and the Code. Were that the intention, some much clearer expression of it would be expected. In some cases, at least, to exclude such interests would infringe seriously on established and legitimate rights, interests and expectations. In my view, that result should not be arrived at by strained implication and in the face of many clear indications of a contrary intention.

266. It is evident from the Court Decision that the circumstances of the purchase of the DBNGP require consideration of values of the Initial Capital Base outside of the range contemplated by section 8.11. In view of this I have looked to other provisions of section 8.10 of the Code and to the objectives of section 8.1 for the purposes of

[80] [2002] WASCA 231 para 176, 177.

[81] [2002] WASCA 231 para 178.

[82] [2002] WASCA 231 para 179.

determining whether there is justification for establishing the value of the Initial Capital base outside the range contemplated by section 8.11.

267. As I have already indicated in my discussion of section 8.10(d) of the Code, the proposed Initial Capital Base is inconsistent, or likely to be inconsistent, with some of the objectives of 8.1(b), 8.1(d) and 8.1(e). It is also likely to have little direct relevance to the objectives of 8.1(c) and 8.1(f) (paragraphs 129 to 161).

268. In view of the inconsistency of the proposed Initial Capital Base for the DBNGP with many of the objectives of section 8.1, I have examined the proposed Initial Capital Base guided by the factors of section 2.24. Epic Energy has sought to substantiate its proposed Initial Capital Base by reference to the factors of sections 2.24(a), 2.24(d) and 2.24(e). I examine these factors here in relation to the proposed Initial Capital Base, noting that I return to the factors of section 2.24 later in these reasons in relation to my consideration of Epic Energy's Reference Tariff and Reference Tariff Policy.

269. Section 2.24(a) of the Code requires that I take into account the Service Provider's legitimate business interests and investment in the Covered Pipeline.

270. The requirement for me to take account of the legitimate business interests of the Service Provider under section 2.24(a) has been given considerable attention by Epic Energy in information put to me in support of the proposed value of the Initial Capital Base.

271. Epic Energy's case for valuation of the Initial Capital Base at the cost of purchase of the DBNGP appears to have two limbs: firstly, that the costs incurred by Epic Energy in the purchase were reasonable, and, secondly, that it is consistent with Epic Energy's legitimate business interests to have regulated tariffs provide for a return on, and a return of, Epic Energy's investment in the DBNGP as represented by the cost of purchase.

272. The reasons cited by Epic Energy in support of its contention that the costs incurred by Epic Energy in the purchase were reasonable include:

- the design of the Sale Process would have resulted in a sale price representing a reasonable market valuation of the DBNGP,[83] reflecting that –
    - as part of the Sale Process indications were made to bidders that a tariff of \$1.00/GJ to Perth would apply under the Code;
    - the two-stage bid process of the sale would have motivated bidders in the pipeline to be conservative in the value of their bids and thus would have mitigated potential for the winning bidder to bid more than a reasonable market value for the pipeline and thus suffer the "winners curse";
    - the prospect of a bidder making an unreasonably high bid would be mitigated by all bidders being provided with the same information in relation to the DBNGP business and related matters;[84]

[83] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.12.

- further evidence for the reasonableness of Epic Energy's bid for the DBNGP lies in –
  - support of the bid by debt financiers;[85]
  - Epic Energy's thorough due diligence of demand forecasts for the DBNGP;[86]
  - other bidders having based bids on similar assumptions as to future volumes of gas being transported through the DBNGP and similar tariffs applying subsequent to 1 January 2000;
  - Epic Energy's *ex post* analysis of its purchase of the DBNGP indicated that the second highest complying bid for the DBNGP was only 7.5 percent less than the Epic Energy bid;[87] and
- the other components of Epic Energy's actual investment – the transaction costs incurred by Epic Energy in purchasing the DBNGP and the subsequent expansion cost (of $121.6 million) – were reasonable costs.[88]

273. The reasons cited by Epic Energy in support of its contention that it is within Epic Energy's legitimate business interests to have the opportunity to recover its investment in the DBNGP, and for this recovery to be explicitly provided for in determination of the value of the Initial Capital Base, appear to include:

- the objectives and process of sale of the DBNGP were determined by the State Government with a primary objective of maximising the sale price and by virtue of this the State must have anticipated and implicitly sanctioned the recovery of those returns by the successful bidder;[89]
- following from the Full Court's observation that it may be legitimate for Epic Energy to recover monopoly rent in setting tariff levels, if the State extracted capitalised monopoly profits (which, after all, accrued for the general benefit of all Western Australians) as part of the sale price, it is legitimate for Epic Energy to pass on this component of the cost to Users;[90]
- Epic Energy is entitled to earn a return which allows it sufficient profits to operate as a viable commercial business, to the extent that Epic Energy has made reasonable and appropriate forecasts as to future demand, and such a return is essential if private operators of infrastructure assets are to exist;[91]

---

[84] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.33 and following

[85] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.30 and following.

[86] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.39 and following

[87] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.50.

[88] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.51.

[89] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.10, 4.13.

[90] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.71.

[91] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.72.

- Epic Energy should be allowed to earn an appropriate return on its investment to permit it to stay in business, and to provide a reasonable and appropriate return to its stakeholders;[92]

- it is within Epic Energy's legitimate business interests that it should be permitted to earn an appropriate level of return upon its ownership of the pipeline to allow it to invest in the expansion of the pipeline;[93] and

- Epic Energy seeks only to be afforded the opportunity to recover its investment once-over.[94]

274. I will address Epic Energy's contentions in respect of each of the two limbs of its case for valuation of the Initial Capital Base at the cost of purchase of the DBNGP.

275. In regard to Epic Energy's contention that the purchase price for the DBNGP was reasonable, I refer to my observations on the purchase price as outlined already in the reasons, in relation to section 8.10(j) of the Code. On the evidence before me, I am not satisfied that the value of Epic Energy's bid for the DBNGP was dependent upon statements made by the Government as to the potential value of regulated tariffs after 1 January 2000. Moreover, I am satisfied that the purchase price did not reflect reasonable commercial judgment due to failure to give any or any sufficient weight to a substantial downside risk in the rate of return that it was assumed would be approved by an independent regulator.

276. Epic Energy's contention that the second highest bid for the DBNGP was 7.5 percent less than the Epic Energy bid is incorrect. I have examined all of the final bids made for the DBNGP. I note that all the other complying bids were lower than Epic Energy's bid by amounts well in excess of 7.5 percent. The other bidders also made substantially different assumptions.[95]

277. In regard to Epic Energy's contention that it is within Epic Energy's legitimate business interests to have the opportunity to recover its investment in the DBNGP, and for this recovery to be explicitly provided for in determination of the value of the Initial Capital Base, I also refer to my previous consideration of the Sale Process and Epic Energy's purchase price (paragraph 185 and following).

278. From the information provided to me I am satisfied that at the time of the sale neither the Government nor Epic Energy gave material consideration to a prospect of the Initial Capital Base being valued at the price bid by Epic Energy, nor that Epic Energy gave material consideration to a value of the Initial Capital Base other than at or close to a DORC value.

279. Moreover, while Epic Energy anticipated a prospect of capturing returns that may be regarded as monopoly profits and factored these returns into its purchase price, this

[92] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.72.

[93] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.73.

[94] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.74.

[95] The relevant details of the bids, other than Epic Energy's, appear as confidential Annexure B to this, my Final Decision.

prospect rested on assumptions made by Epic Energy and/or its advisors, which I have found to be unreasonable, rather than on any representations made by the Government.

280. Finally, Epic Energy contends that it is entitled to earn a return that allows it sufficient profits to operate as a viable commercial business and be permitted to earn an appropriate level of return upon its ownership of the pipeline to allow it to invest in the expansion of the pipeline. However, under its proposed Access Arrangement, Epic Energy does not anticipate charging tariffs derived from its proposed Initial Capital Base within the foreseeable future. These contentions do not substantiate a claim to value the Initial Capital Base at the purchase price for reasons of operating as a viable commercial business.

281. Section 2.24(d) of the Code requires that the Regulator take into account the economically efficient operation of the pipeline.

282. Epic Energy has sought to substantiate valuation of the Initial Capital Base at the cost of purchase by reference to section 2.24(d). Epic Energy contends that:

> …it is appropriate, and economically efficient, to adopt a rule which bases its Reference Tariff upon the historical cost of purchasing the DBNGP (at least to a substantial extent). This is because of an important policy consideration. Backward looking rules, which set access charges depending on costs at the time of investment, are more successful at promoting investment. Like forward looking rules, they allow the firm to shift the cost of investing earlier onto its users, who enjoy the benefit of an investment which would not otherwise have been made. Unlike forward looking rules, they do not expose the firm to the risk of future movements of costs.[96]

283. Epic Energy appears to contend that valuation of the Initial Capital Base at the cost of purchase is consistent with economic efficiency because a value of the Initial Capital Base at less than the value of investment by Epic Energy would result in a less than efficient level of investment in pipelines and similar assets.

284. I examined above the implications of different valuations of the Initial Capital Base for investment incentives in relation to section 8.10(d) of the Code, and the objective of section 8.1(d). My conclusions in this regard were that:

- a valuation methodology that derives an Initial Capital Base value at or above the DAC value should provide sufficient comfort to investors in pipelines that actual capital cost of investment will be recognised in subsequent regulation, and hence not be to the detriment of incentives for efficient investment in pipeline construction;

- valuation of the Initial Capital Base of an existing pipeline at a value below the purchase price would not necessarily affect incentives to invest in, and operate, pipelines, although it may affect the prices that investors would pay for existing pipelines;

- distortion of incentives for investment in new pipelines may occur if more favourable regulatory outcomes can be achieved for existing pipelines than for new pipelines; such as through a higher valuation of the Initial Capital Base for an

[96] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.99.

existing pipeline than for an equivalent new pipeline, which would occur if an existing pipeline is valued by a methodology that gives rise to values based on other than the value of construction of the pipeline infrastructure, i.e. a DAC or DORC value; and

- although the purchase of the DBNGP was an arm's-length commercial transaction, the price paid was not based upon sound commercial assessment of the value of the pipeline in the circumstances then prevailing and anticipated, by reason of Epic Energy's failure to recognise a substantial downside risk in its assumption of a rate of return that would be approved by a regulator, and hence the tariffs that would be approved by a regulator.

285. In these circumstances I am of the view that valuation of the Initial Capital Base at Epic Energy's cost of purchase is not supported by consideration of section 2.24(d) of the Code.

286. Section 2.24(e) of the Code requires that the Regulator take into account the public interest, including the public interest in having competition in markets (whether or not in Australia).

287. Epic Energy has drawn on section 2.24(e) in support of its case for both its proposed Reference Tariff, and its proposed Initial Capital Base. In regard to the Initial Capital Base, Epic Energy makes the following contentions.

- The Western Australian public has benefited from the sale proceeds of the DBNGP.[97]

- The State Government made a conscious decision to accept the highest bid for the DBNGP (on the basis of a tariff of $1/GJ to Perth) rather than to accept the bid offering the lowest tariff. This was due to the State Government's positive decision that it was of greater public interest to obtain a high bid, than to have a low tariff, so long as existing tariffs were reduced to the level of $1/GJ to Perth.[98]

- A major source of funds provided by equity participants in the DBNGP purchase, was from superannuation trustees conducting business in Australia. Deutsche Asset Management holds its interest for the NSW State Superannuation Fund. In addition, AMP's interest is for the benefit of other superannuation funds. The State Government was aware of this fact. To the extent that the Regulator may decide to reduce the capital value of the DBNGP for the purposes of calculating a return on investment, the funds at most risk are those provided by the equity participants, i.e. people employed throughout Australia.[99]

288. I accept that there is a public interest in the Western Australian public having received benefit from the proceeds from sale of the DBNGP. I also take into account that erosion of the financial viability of a company may be contrary to the public interest where there are potentially high impacts on other companies and on society.

[97] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.109.

[98] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.111.

[99] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 4.113.

However, the public interest extends beyond these factors and would include the public interest in having competition in markets (as specifically recognised by the Code) and a public interest in a supply of competitively-priced gas. The proposed Initial Capital Base is contrary to these broader aspects of the public interest. Epic Energy's contention that an Initial Capital Base equal to the purchase price is justified by the public interest of the benefits to the State from the sale proceeds would displace other aspects of public interest. However, where the purchase price was not induced by representations by the Government as to the public interest, this reason for setting the Initial Capital Base equal to the purchase price is less compelling.

289. After considering the factors of 8.10 of the Code and examining Epic Energy's proposed Initial Capital Base for the DBNGP against the objectives of section 8.1 and guided by the factors of section 2.24, I am not satisfied that valuation of the Initial Capital Base on the basis of Epic Energy's cost of purchase is an approach that best satisfies the relevant principles and objectives of the Code. Rather, I am of the view that the Initial Capital Base should be established at a lower value giving sufficient recognition to the interests of Users and Prospective Users. I address this further in my assessment of the Reference Tariff and Reference Tariff Policy, and my statement of the amendments that must be made to the Access Arrangement in order for me to approve it.

New Facilities Investment

290. Sections 8.15 to 8.21 of the Code provide for capital costs incurred in New Facilities Investment to be included in the Capital Base of a Covered Pipeline, and for capital costs forecast for an Access Arrangement Period to be considered in determination of Reference Tariffs for that Access Arrangement Period.

291. Section 8.16 of the Code sets out criteria that must be met by any New Facilities Investment if the actual capital cost of that investment is to be added to the Capital Base. These criteria are:

(a) Subject to sections 8.16(b) and sections 8.20 to 8.22, the Capital Base may be increased under section 8.15 by the amount of the actual New Facilities Investment in the immediately preceding Access Arrangement period provided that:

i. that amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services; and

ii. one of the following conditions is satisfied –

A. the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or

B the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or

C. the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

(b) If pursuant to section 8.20 the Relevant Regulator agrees to Reference Tariffs being determined on the basis of forecast New Facilities Investment, the Capital Base may be increased by the amount of the New Facilities Investment forecast to occur within the new

Access Arrangement Period determined in accordance with sections 8.20 and 8.21 and subject to adjustment in accordance with 8.22.

292. Section 8.17 of the Code sets out two factors that the Regulator must consider in determining whether Capital Expenditure meets the criteria set out in section 8.16:

(a) whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and

(b) whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over that time frame.

293. Section 8.18 of the Code allows for a Reference Tariff Policy to state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of section 8.16, and for the Capital Base to be increased by that part of such investment that does satisfy section 8.16 (the Recoverable Portion). Section 8.19 of the Code allows for an amount of the balance of the investment to be assigned to a Speculative Investment Fund, and to be added to the Capital Base at some future time if the criteria of section 8.16 are met. Section 8.19 also sets out the manner in which the value of the Speculative Investment Fund is determined at any time.

294. Section 8.20 of the Code provides for Reference Tariffs to be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period provided that the investment is reasonably expected to pass the requirements of section 8.16 when the investment is forecast to occur. This does not, however, mean that the forecast New Facilities Investment will automatically be added to the Capital Base after it has occurred (section 8.21). Rather, the Regulator will assess whether the investment meets the criteria of section 8.16 of the Code either at the time of review of the Access Arrangement or at any other time if asked to do so by the Service Provider.

295. Section 8.22 of the Code requires that either the Reference Tariff Policy should describe, or the Regulator shall determine, how the New Facilities Investment is to be determined for the purposes of additions to the Capital Base at the commencement of the subsequent Access Arrangement Period. This includes how the Capital base at the commencement of the next Access Arrangement Period will be adjusted if the actual New facilities Investment or Recoverable Portion (whichever is relevant) is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in section 8.1).

296. Sections 8.23 to 8.26 of the Code set out provisions for New Facilities Investment to be financed in whole or in part by capital contributions from Users, or from surcharges over and above Reference Tariffs to be charged to Users.

297. Epic Energy addresses New Facilities Investment as part of its Reference Tariff Policy in sub-clause 7.8 of the proposed Access Arrangement.

(a) New facilities investment during the Access Arrangement Period is reasonably expected to pass the requirements of section 8.16 of the Code when the new facilities investment is forecast to occur.

(b) For the purposes of calculating the capital base at the commencement of the next Access Arrangement Period in accordance with section 8.9 of the Code, the new facilities investment will consist only of actual new facilities investment that has occurred during this Access Arrangement period.

298. Details of planned Capital Expenditure for the Access Arrangement Period are provided in sections 3.6 and 3.7 of the Access Arrangement Information – summarised as follows with values converted to real dollar values.

Epic Energy forecast Capital Expenditure
(31 December 1999 $million, year ending 31 December)

Type of Investment	2000	2001	2002	2003	2004	Total
Pipeline Expenditure						
Flood damage mitigation		0.05	0.05	0.05	0.05	0.20
Pipeline protection		0.20		0.20		0.40
Mainline valve CCVT upgrade			0.08	0.08	0.08	0.24
Mainline valve GEA upgrades		0.04	0.04	0.04		0.12
Mainline valve and repeater earthing	0.03	0.03	0.03	0.03	0.03	0.15
WLPG heat exchanger	0.40					0.40
Total Pipeline Expenditure	**0.43**	**0.32**	**0.20**	**0.40**	**0.16**	**1.50**
Compression Expenditure						
Turbine/Compressor Upgrades	20.19	1.3	1.40			22.89
UPS upgrade		0.15	0.15	0.15	0.15	0.60
Airstrip upgrade	0.15	0.20	0.20			0.55
Water treatment plants		0.05	0.05	0.05	0.05	0.20
Air conditioning units		0.05	0.05	0.05	0.05	0.20
Compressor station facilities	0.11	0.05				0.16
Station MMI upgrades		0.03	0.10	0.08	0.10	0.31
Portable flares		0.02				0.02
Sulphur deposition mitigation		1.00	1.00			2.00
Greenhouse NOx/SOx control		1.50	1.50	1.50	1.50	6.00
Total Compression Expenditure	**20.45**	**4.35**	**4.45**	**1.83**	**1.85**	**32.93**
Metering Expenditure						
Meter Station noise control		0.05	0.05	0.05	0.05	0.20
Other Expenditure						
Microwave system upgrade	0.25	3.80	4.70	3.80		12.55
VHF communications upgrade		0.20	0.25	0.20		0.65
SCADA upgrade		0.30	0.25	0.20		0.75
Customer reporting system	2.40					2.40
Computer system upgrades	0.62	0.15	0.15	0.15	0.15	1.22
Information management system	0.50					0.50
SCADA master station protocols		0.08				0.08
SCADA master station CS6, 9 visibility	0.10					0.10
Motor vehicles		0.25	0.25	0.25	0.25	1.00
Tools and equipment	0.28	0.05	0.05	0.05	0.05	0.48
Inventory management	0.20	0.20	0.20	0.20	0.20	1.00
Emergency response caravan		0.06				0.06
Buildings	0.30	0.10	0.10	0.10	0.10	0.70
Security systems		0.10				0.10
Fitness for purpose project	0.60					0.60
Corrosion protection upgrades			0.02	0.02	0.02	0.06
Land management (GIS)	0.06					0.06
Total Other Expenditure	**5.31**	**5.29**	**5.97**	**4.97**	**0.77**	**22.31**
Total	**26.19**	**10.01**	**10.67**	**7.25**	**2.83**	**56.95**

299. In my Draft Decision I provided an assessment of the forecast New Facilities Investment on a “project-by-project” basis against the requirements of sections 8.20 and 8.21 of the Code, giving attention to whether the forecast New Facilities Investment is reasonably expected to pass the requirements of section 8.16 of the Code at the time that the New Facilities Investment is forecast to occur. I indicated that expenditure on several projects was poorly justified and that while the expenditure would be deemed likely to satisfy the requirements of section 8.16 of the Code for the purposes of the Draft Decision, more rigorous justification of the expenditure would be required before the associated New Facilities Investment would be rolled into the Capital Base. The expenditure items in question are:

- WLPG heat exchanger;
- compressor station computer facilities and software;
- sulphur deposition mitigation programme;
- microwave system upgrade;
- replacement of remote terminal units;
- customer reporting system;
- computer system upgrades; and
- information management system.

300. Despite further justification of the proposed New Facilities Investment ultimately being required before the value of this investment would be rolled into the Capital Base, I took the view in the Draft Decision that the proposed costs were adequately justified for the purposes of recognising the forecast costs in determination of the Reference Tariff for the current Access Arrangement Period, and I did not seek any revision of the forecast costs. I did, however, seek two changes to the manner in which forecast capital expenditure was accommodated in the determination of Total Revenue:

- forecast costs indicated for the cost classifications of flood damage mitigation, GEA upgrades, maintenance of tools and equipment and inventory management are in the nature of non-capital costs and should be incorporated in the forecast Non Capital Costs for the respective years of the Access Arrangement Period; and
- committed capital expenditure on the Stage 3A compression enhancement should be incorporated into valuation of the Initial Capital Base rather than being considered as forecast capital costs in 2000.

301. In a submission to me subsequent to issue of the Draft Decision, Epic Energy indicated that there is some uncertainty as to whether capital expenditure on items not directly associated with the pipeline assets – such as communication systems and computer systems – may be recognised in forecasts of New Facilities Investment for the purposes of determining Total Revenue and, ultimately, rolled into the Capital

Base. This is an issue I have previously considered in respect of New Facilities Investment to be undertaken by AlintaGas in relation to full retail contestability.[100]

302. Subsequent to Epic Energy's submission, amendments have been made to the Code to address this issue and allow the relevant classes of New Facilities Investment to be recognised. These amendments came into effect on 17 April 2003 pursuant to the Seventh Amending Agreement of the Code. Where there are statutory powers being exercised, and in the absence of any contrary statutory intention, it is proper to apply the provisions of the relevant statute at the time of exercise of the power. Accordingly I am obliged to make my assessment of the proposed Access Arrangement on the basis of the Code as it exists at the time of my Final Decision. The relevant elements of the forecast New Facilities Investment are therefore able to be taken into account in determination of the Reference Tariff.

303. In its submission to me Epic Energy has also noted that in my Draft Decision I indicated that the information provided in respect of some elements of forecast New Facilities Investment would be inadequate to meet the requirements for the Regulator to approve the rolling in of such expenditure into the Capital Base. Epic Energy has provided further information on the relevant items of forecast New Facilities Investment, seeking assurance from me that this expenditure will be able to be rolled into the Capital Base at the commencement of the next Access Arrangement Period.

304. While I understand Epic Energy's concern for certainty in respect of determination of the Capital Base for the next Access Arrangement Period, it is not part of my assessment of the proposed Access Arrangement to approve the "rolling in" of items of capital expenditure into the Capital Base. This would be a matter for the Regulator of the time to address either when specifically asked to do so by Epic Energy (in advance of the expenditure actually occurring and in accordance with the provisions of section 8.21 of the Code) or when revisions to the Access Arrangement are being considered and the value of the Capital Base at the commencement of the next Access Arrangement Period is being determined.

305. As a final matter in relation to forecast New Facilities Investment, Epic Energy has submitted to me that three of the cost items that I considered should be regarded as Non Capital Costs (flood-damage mitigation, maintenance of tools and equipment, inventory management) are costs of a capital nature.

306. In regard to flood-damage mitigation, Epic Energy has argued that the works are of a capital nature, aimed to prevent damage, rather than of a maintenance or repair nature and thus should be considered as capital costs. I accept Epic Energy's submission on this matter.

307. In regard to maintenance of tools and equipment, Epic has cited accounting standards to indicate that "spare parts" are properly regarded as capital items, with Epic Energy suggesting that this also applies to tools and maintenance of tools. Epic Energy's submission does not support its case for maintenance of tools to be considered a

[100] Acting Independent Gas Pipelines Access Regulator, Western Australia, 27 December 2002, Information Paper: Recover of Costs, Introduction of Full Retail Contestability, Mid West and South West Gas Distribution Networks of Western Australia.

capital cost, which is a different matter than the purchase of tools and equipment and which would not appear relevant to the accounting standards cited by Epic Energy. I thus maintain the view that these costs should be regarded as Non Capital Costs for the purposes of determining Reference Tariffs.

308. In regard to inventory management, Epic Energy has again cited accounting standards to indicate that inventories of spare parts are properly regarded as capital items. However, the costs referred to by Epic Energy for inventory management relate to ongoing studies to improve the management of inventories rather than costs of the inventory itself. As such, I do not consider that there is reason for me to change my view that these costs should be regarded as Non Capital Costs for the purposes of determining Reference Tariffs.

309. The forecast costs of New Facilities Investment revised in accordance with the above are as follows (31 December 1999 $million).

Year ending 31 December	**2000**	**2001**	**2002**	**2003**	**2004**	**Total**
Pipeline	0.43	0.28	0.16	0.36	0.16	1.38
Compression	0.96	4.35	4.45	1.83	1.85	13.44
Metering	0.00	0.05	0.05	0.05	0.05	0.20
Other	5.06	5.04	5.72	4.72	0.52	21.06
Total	6.45	9.62	10.28	6.86	2.48	35.69

Rate of Return

310. Sections 8.30 and 8.31 of the Code state the principles for establishing the Rate of Return used in determining a Reference Tariff:

> 8.30 The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).
>
> 8.31 By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

311. Epic Energy has addressed the Rate of Return in its Reference Tariff Policy, indicating in sub-clause 7.5 of the Access Arrangement that:

> (a) The rate of return has been set as a weighted average of the returns applicable to debt and equity.
>
> (b) The return on equity referred to in paragraph 7.5(a) has been determined using the capital asset pricing model.
>
> (c) The return on debt referred to in paragraph 7.5(a) has been determined as the sum of a risk free rate of return and the estimated corporate debt premium.

312. Epic Energy's estimate of the weighted average cost of capital (WACC) is described in Appendix 2 of the Access Arrangement Information. The parameter values of the CAPM used by Epic Energy for this estimation of the WACC are indicated in the table below. On the basis of these parameter values, Epic Energy has proposed a real pre-tax WACC of 8.5 percent (11.2 percent in pre-tax nominal terms).

313. In assessing the derivation of the WACC for the purposes of the Draft Decision I undertook:

- a review of the methodology employed by Epic Energy for calculation of the WACC and of the reasonableness of the values adopted for specific variables; and

- re-calculation of the cost of capital applicable to the DBNGP business based on a methodology and values of input variables determined by me to be appropriate.

314. I adopted a similar methodology to that of Epic Energy in applying the Capital Asset Pricing Model to the determination of a WACC,[101] but with some differences of view in regard to values of input variables to the WACC calculation. A comparison of values of input variables used by Epic Energy with values that I considered reasonable is provided as follows.

[101] There are a number of different versions of the CAPM for determination of the after-tax WACC, which are derived by transferring one or more of the particular costs or benefits from the cash flows to inclusion in the WACC formula. I have used the "Officer" WACC, which has the following formula:

$$WACC = R_e \cdot \frac{E}{V} \cdot \frac{1-t_c}{(1-t_c(1-g))} + R_d \cdot \frac{D}{V} \cdot (1-t_c)$$

where $\frac{E}{V}$ and $\frac{D}{V}$ are equity and debt as shares of total assets, V, R_e is the cost of equity, R_d is the cost of debt, t_c is the corporate tax rate, and g is the value of franking credits created. Epic Energy used a variation of the Officer WACC whereby the *gamma* term was replaced by a function of the utilisation of franking credits (q); the dividend payout ratio (a); and a factor reflecting the ratio of franked dividends to total dividends (k). Its formula for the post tax WACC was therefore:

$$WACC = R_e \cdot \frac{E}{V} \cdot \frac{1-t_c}{(1-t_c(1-a.kq))} + R_d \cdot \frac{D}{V} \cdot (1-t_c)$$

Proposed and Draft Decision CAPM Parameter Values

Parameter	Parameter symbol	Epic Energy	Draft Decision
Risk free rate (nominal)	R_f	6.40%	5.96%
Market risk premium	–	6.50%	6.0%
Asset beta	b_a	0.58	0.60
Equity beta	b_e	1.15	1.20
Debt beta	b_d	0.12	0.20
Cost of debt margin		1.20%	1.20%
Corporate tax rate	T	36%	31.4%
Franking credit value	g	44% [102]	50%
Debt to total assets ratio	D/V	55%	60%
Equity to total assets ratio	E/V	45%	40%
Expected inflation	p_e	2.5%	2.48%
Estimated Return on Equity			
Nominal post-tax		13.90	13.16%
Real post-tax		11.12	10.42%
Nominal pre-tax		17.41	15.61%
Real pre-tax		14.55	12.81%
Estimated WACC			
Nominal post-tax		7.69%	7.23%
Real post-tax		5.06%	4.64%
Nominal pre-tax		11.21%	10.54%
Real pre-tax		8.50%	7.87%

315. Rounding the real pre-tax WACC to the nearest five basis points, I adopted a value of 7.85 percent for the purposes of my Draft Decision.

316. In a submission to me, Epic Energy contests my deliberations on the Rate of Return on a number of points related to both the process under the Code for determining a Rate of Return, and my deliberations under the Draft Decision in respect of the values of certain parameters of the CAPM. I address these as follows.

[102] While Epic Energy stated an assumed franking credit (gamma) value of 0.44, in calculating WACC values it scaled this value by a dividend payout ratio of 0.7 to give an effective dividend credit value of 0.308.

317. The first matter raised by Epic Energy concerns the process under the Code for determining the Rate of Return:[103]

> The Regulator's approach to the question of the appropriate rate of return in his draft decision dated 21 June 2001 was to assess the rate of return which he considered appropriate, and reject the rate proposed by Epic Energy as it did not match his own determination. That approach is flawed. As previously emphasised, the approach that the Regulator ought to adopt, as was made clear by the comments of Parker J on 28 November 2002, is to ask himself the question whether the rate of return proposed by Epic Energy is outside the legitimate range which could reasonably be allowed. It is beside the point if the Regulator himself might favour another outcome within the legitimate range. He can only reject the proposed rate of return advanced by Epic Energy if he can demonstrate that it is commercially unreasonable or unjustified. Quite apparently, the draft decision does not set out to address that question.

318. In addressing Epic Energy's submission, I refer to sections 8.30 and 8.31 of the Code. Section 8.30 requires the Rate of Return that is factored into the assessment of the Reference Tariff to reflect the cost of capital associated with delivering the Reference Service. Section 8.31 provides additional guidance on how to estimate the cost of capital. It specifically allows for returns to be determined on the basis of a well-accepted financial model, such as the CAPM. Section 8.31 also encourages the use of benchmarks for such matters as financing arrangements.

319. The other relevant guidance for determination of the Rate of Return is provided in section 8.2(e) of the Code. The "return which is commensurate with prevailing conditions in the market for funds involved in delivering the Reference Service" is a parameter that cannot be observed, but can only be estimated and forecast for the Access Arrangement Period. Accordingly, the Code also requires that the estimate of this return reflect a "best estimate arrived at on a reasonable basis".

320. It can be noted that, while there is a degree of statistical uncertainty associated with the estimation and forecasting of the cost of capital associated with an activity, section 8.2(e) of the Code requires that the Rate of Return reflect the *best* estimate of the true cost of capital. While conventional statistical analysis may not be able to disprove definitively a value within a range – and potentially a wide range – all values within that range are not equally plausible.[104] The Code requires the selection of the *best* value from within any such range and I am thus required to reach a view as to whether the proposed Access Arrangement complies with the requirements of the Code.

321. Epic Energy also states in its submission that I, as the Regulator under the Code, can only reject the proposed rate of return advanced by Epic Energy if I can demonstrate

---

[103] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.39.

[104] There are a number of different technical criteria in statistics for defining the best value for an estimator. One definition is that the best value is that which has the lowest estimation error (variance) amongst the class of unbiased estimators (unbiased means that, if the experiment were run many times, the true value would be obtained, on average). However, alternative criteria imply that the best measure should allow a degree of bias in the estimator if this achieves more than a compensating reduction in the variance of the estimator (mean square error is an example). In practice, however, the derivation of the best estimators for many of the inputs required to estimate a cost of capital require information from a number of different sources to be taken into account, which cannot be undertaken with a mechanical algorithm, but rather requires judgement to be exercised.

that it is commercially unreasonable or unjustified.[105] For the reasons already stated, this submission is rejected.

322. The second matter raised by Epic Energy relates to the point in time at which the Cost of Capital is estimated. Use of the CAPM requires estimation of a risk-free rate of return and a forecast rate of inflation. In my Draft Decision, I indicated a preference for estimating the nominal risk free rate from a recent average of the yields on Commonwealth bond rates, the real risk free rate from a recent average of the yields on Commonwealth index-linked bonds over the same period, and calculating the inflation forecast as the difference between these yields. In my Draft Decision I used the yield to maturity on 10 year Commonwealth Government Treasury Bonds as a proxy for the nominal risk free rate and the yield to maturity on the 10 year Commonwealth Government Capital Indexed Treasury Bonds as the proxy for the real risk free rate. The observed yield for the relevant bonds was taken as the average of the 20 trading days to 31 May 2001, which was three weeks before issue of the Draft Decision.

323. Epic Energy submits that:[106]

> [T]he date at which the rate of return is assessed should be the date of the commencement of the access arrangement period. Epic Energy should not be prejudiced from any movements over time in the market variable elements of the rate of return calculation just because of a delay in the regulatory approval process. This is consistent with both the task of the Regulator in assessing a service provider's access arrangement and with the need to promote regulatory certainty over set periods.

324. I take the view that the latest information should be used in estimating the cost of capital. The use of new information is consistent with the requirement of section 8.2(e) of the Code that the estimate of the cost of capital be a best estimate. I consider it appropriate that an estimate be used of the current risk free rate of return.

325. The third matter raised by Epic Energy relates to the assumption of capital structure (ratio of debt to equity) used in estimation of the cost of capital, which is a weighted average of the estimated costs of debt and equity. Epic Energy submits that:[107]

> Epic Energy's derivation of the rate of return used a capital structure comprising 55% debt and 45% equity. This capital structure was, in the view of Epic Energy's expert adviser on rate of return, The Brattle Group, consistent with evidence from Australia and overseas on the capital structures of comparable companies. Gearing ratios (levels of debt to total assets) for those companies, summarized in The Brattle Group's report, were in the range 50% to 60%.
>
> In his Draft Decision, the Regulator required the use of a capital structure comprising 60% debt and 40% equity. No evidence supporting the use of this capital structure was provided, and no argument was presented that Epic Energy's proposal was commercially, or otherwise, unreasonable.

326. In accordance with Epic Energy's submission, I accept that observations of capital structure amongst similar companies are a legitimate input into making an assumption

[105] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.39, 9.41, 9.43.

[106] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.40.

[107] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.42, 9.43.

about capital structure. However, I consider the following two principles should be observed in using such observations.

- Firstly, companies that are "more similar" to the business under consideration are more relevant, that is, companies that are closer to "pure-play" gas transmission or distribution entities with regulation of activities. Cash flows from regulated activities are likely to be more certain and capable of sustaining higher levels of gearing (for a given credit rating). Unregulated activities would lower the debt able to be carried (or, equivalently, reduce the expected credit rating for a given level of debt). As an estimate of the cost of capital is being made for the regulated activities only of Epic Energy, the presence of unregulated activities in companies from which observations of capital structure are made would tend to bias downwards the assumed level of debt.

- Secondly, the optimal level of gearing of a company reflects a number of factors, including tax law, bankruptcy provisions, etc., many of which may vary across countries. As such, observations of capital structure for domestic firms are more relevant.

327. The Essential Services Commission of Victoria has cited gearing levels for a range of Australian gas transmission and distribution companies, comprising AGL, Envestra. United Energy, Australian Pipeline Trust, GasNet and AlintaGas, for which gearing levels at June 2000 range from 35 percent (AlintaGas) to 74 Percent (Envestra).[108] The simple average of these gearing levels is 54 percent. However, restricting the sample to near pure-play regulated gas transmission and distribution companies (i.e. excluding AlintaGas, United Energy and AGL) changes the average to 66 percent. This suggests that the assumption of 55 percent gearing used by Epic Energy is below the gearing level suggested by market evidence. For the purposes of this Final Decision, I consider that an assumption of 60 percent gearing is appropriate and, if anything, conservative.

328. The final matter raised by Epic Energy in relation to the Rate of Return is that of assumptions related to dividend imputation:[109]

> Epic Energy proposed that the value of franking credits available to shareholders under the dividend imputation provisions of the Australian taxation system be recognized through use of a value of GAMMA of 44% in its derivation of the rate of return. The parameter GAMMA measures the ratio of utilized franking credits to corporate tax paid on income paid out of dividends.
>
> At the time Epic Energy submitted its proposed Access Arrangement to the Regulator (December 1999), allowance for dividend imputation in the derivation of the rate of return was still relatively new and somewhat contentious. No allowance had been made for it in the tariff analysis undertaken by Price Waterhouse, for the Government of Western Australia, in August 1997, and later made available, in the sale data room, to bidders for the Pipeline. Epic Energy's expert advisor on rate of return, The Brattle Group, sought to estimate GAMMA as the product of a franking credit utilization factor (the proportion of franking credits that are redeemed) and a franking ratio (the ratio of franked dividends to total dividends). Values for the franking credit utilization factor, and for the franking ratio, were obtained from a number of studies by Australian finance academics. These studies indicated a utilization factor of 55%, and a franking ratio of

[108] Essential Services Commission, October 2002, Review of Gas Access Arrangements, Final Decision, p 360.

[109] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.44 – 9.47.

> 80%. Accordingly, The Brattle Group's estimate of GAMMA was 44% (55% x 0.80). In applying this estimate, an adjustment was made for the dividend payout ratio (estimated to be 0.70), so that the effective value of GAMMA in The Brattle Group's derivation of a rate of return for the DBNGP was 30.8% (0.70 x 44%).
>
> In his Draft Decision, the Regulator refers to a more recent study that indicates a higher value for the franking ratio, and that consistent application of the Capital Asset Pricing Model in the derivation of a return on equity requires the assumption that all investors are Australian and can fully utilize franking credits. According to the Regulator, these two factors suggest a franking credit utilization factor higher than the 55% assumed by Epic Energy. Further arguments are advanced by the Regulator which purport to show that the transformation method used by Epic Energy (and by the Regulator) to account for the effects of taxation requires assumption of a higher rather than a lower value for GAMMA. On the basis of the additional evidence, and these more theoretical arguments, the Regulator concludes that the appropriate value for GAMMA is that which has been assumed for other regulatory decisions in Australia.
>
> There appears to be no basis for this conclusion, other than the fact that other regulatory decisions have assumed (without justification) a value of GAMMA of 50%, which is higher than the estimate used by Epic Energy.

329. In response to this submission from Epic Energy I refer to my Draft Decision in which these matters are addressed.[110] I have also undertaken further analysis of this issue which has indicated that Epic Energy's contentions are not supported by empirical evidence and research studies subsequent to my Draft Decision.[111]

330. After consideration of the submissions made to me in respect of the Rate of Return, I take the view that the Rate of Return proposed by Epic Energy over-estimates the current cost of capital that would apply to the activities of the DBNGP, at current interest rates. I consider that the Rate of Return should be revised to 7.4 percent (rounded to the nearest five basis points), reflecting CAPM parameters and market interest rates as follows.

[110] Draft Decision, Part B pp 205 – 209.

[111] Refer to Appendix 1 of this Final Decision.

Revised CAPM Parameter Values and Rate of Return

Parameter	Parameter symbol	Final Decision
Risk free rate (nominal)	R_f	5.28%
Market risk premium	–	6.0%
Asset beta	b_a	0.60
Equity beta	b_e	1.20
Debt beta	b_d	0.20
Cost of debt margin		1.20%
Corporate tax rate	T	31.4%
Franking credit value	g	50%
Debt to total assets ratio	D/V	60%
Equity to total assets ratio	E/V	40%
Expected inflation	p_e	2.25%
Estimated Return on Equity		
Nominal post-tax		12.48%
Real post-tax		10.00%
Nominal pre-tax		14.80%
Real pre-tax		12.28%
Estimated WACC		
Nominal post-tax		6.73%
Real post-tax		4.38%
Nominal pre-tax		9.81%
Real pre-tax		7.39%

Depreciation

331. Sections 8.32 to 8.35 of the Code relate to depreciation of assets that form part of the Capital Base, for the purposes of determining a Reference Tariff.

332. Section 8.32 defines a Depreciation Schedule as:

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

333. Section 8.33 requires that the Depreciation Schedule be designed:

> (a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly

where the calculation of the Reference Tariffs has assumed significant market growth and the pipeline has been sized accordingly);

(b) so that each asset or group of assets that form part of the Capital Base is depreciated over the economic life of that asset or group of assets;

(c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the Capital Base is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and

(d) subject to provisions for capital redundancy in section 8.27 of the Code, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base).

334. Section 8.34 provides for the application of depreciation principles in the determination of Total Revenue using IRR or NPV methodologies. If the IRR or NPV methodology is used, then the notional depreciation over the Access Arrangement Period for each asset or group of assets that form part of the Capital Base 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; and

(b) for a New Facility installed during the Access Arrangement Period, the difference between the actual cost or forecast cost of the Facility (whichever is relevant) and the value of that asset that is reflected in the Residual Value,

and, to comply with section 8.33:

(c) the Residual Value of the Capital Base should reflect notional depreciation that meets the principles of section 8.33; and

(d) subject to section 8.27, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base, subject to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to section 8.5A).

335. Section 8.35 of the Code provides for the cash flow needs of the Service Provider to be recognised in the determination of the Depreciation Schedule:

> In implementing the principles in section 8.33 or 8.34, regard must be had to the reasonable cash flow needs for Non Capital Costs, financing cost requirements and similar needs of the Service Provider.

336. The Depreciation Schedule proposed by Epic Energy is described in section 3.4 of the Access Arrangement Information.

337. Epic Energy has determined depreciation schedules for each of four classes of assets that form the DBNGP:

- pipeline assets, with depreciation schedules constructed for each pipeline zone;
- compression assets, with depreciation schedules determined for each compressor station;

- metering assets, with depreciation schedules constructed for each Delivery Point; and
- other assets, depreciated as a single homogenous class of assets.

Capital values ascribed to two components of the Capital Base – land and linepack – are not depreciated.

338. Depreciation of values ascribed to physical assets (the physical asset account) was determined using the annuity method. In general terms, the annuity methodology involves determining a depreciation schedule over the expected lives of assets such that the total annual capital costs (return on capital plus depreciation) are held at a constant value (the "annuity") but assets are fully depreciated over the period of assumed asset lives. By this methodology, the composition of capital costs changes over time with the return-on-capital component decreasing over time and the depreciation component increasing over time.

339. Epic Energy has proposed depreciation of assets over the following asset lives.

Epic Energy assumptions as to asset life

Asset class	Economic life (years)	Average remaining life as at 1 January 2000 (years)
Pipeline assets	100	86
Compression assets	57	49
Metering assets	71	63
Other assets	50	39

340. In the calculation of depreciation schedules, the capital cost of New Facilities Investment is added to the physical asset account and subsequently depreciated by the annuity method over the assumed economic lives for relevant asset classes.

341. With Epic Energy's proposed value of the Initial Capital Base and the proposed Reference Tariff, the expected notional revenue from the DBNGP over the Access Arrangement Period (if all transmission occurred under the Reference Tariff) is insufficient to cover the annuity charges. Epic Energy has proposed treating the shortfall in capital charges by way of "economic depreciation". Under Epic Energy's proposed treatment of capital charges, economic depreciation for a given year is defined as the difference between the expected revenue from the DBNGP in that year (given the Reference Tariff) and the sum of physical asset depreciation, return on the Capital Base, and Non Capital Costs.[112] Where economic depreciation is negative

[112] Section 3.4 of the Access Arrangement Information indicates that economic depreciation was calculated as the difference between forecast revenue and the sum of Capital Expenditure, return on the Capital Base and Non Capital Costs. Table 3.3 of the Access Arrangement reflected calculation of economic depreciation as so described. Calculation of economic depreciation in this way would have the effect of "double counting" Capital Expenditure in the Capital Base. Epic Energy advised the Regulator that the description of economic depreciation in the Access Arrangement Information is incorrect, and that the description should indicate

(revenue is less than the sum of physical asset depreciation, return on the Capital Base, and Non Capital Costs) the difference is added to a deferred recovery account and the balance of this account increases. Where economic depreciation is positive (revenue is in excess of the sum of physical asset depreciation, return on the Capital Base, and Non Capital Costs) the difference is subtracted from the deferred recovery account and the balance of this account decreases. For the purposes of determining the return on capital, the Capital Base comprises the sum of the balances of the physical asset account and the deferred recovery account.

342. Epic Energy's proposed regulatory asset account, incorporating the Depreciation Schedule for the Access Arrangement Period, is as follows.

Epic Energy Regulatory Asset Accounting (nominal $million, year ending 31 December)

	2000	2001	2002	2003	2004
Beginning of year balances					
Physical asset account …(1)	2,570.37	2,596.49	2,606.44	2,617.30	2,624.65
Deferred recovery account …(2)	0.00	106.47	226.98	360.12	505.81
Capital Base (1+2) …(3)	2,570.37	2,702.97	2,833.42	2,978.42	3,130.46
Forecast revenue …(4)	221.23	224.28	228.79	235.96	242.45
Return on Capital Base …(5)	288.20	303.07	317.70	333.96	351.00
Depreciation: physical asset account …(6)	0.39	0.44	0.49	0.55	0.62
Non Capital Costs …(7)	39.11	41.28	44.74	46.14	46.84
Depreciation: deferred recovery account (4–(5+6+7)) …(8)	-106.47	-120.51	-134.14	-144.69	-156.01
New Facilities Investment … (9)	26.51	10.38	11.35	7.90	3.16
End of year balance					
Physical asset account (3+9–2–6) …(10)	2,596.49	2,606.44	2,617.30	2,624.65	2,627.19
Deferred recovery account $\lvert\Sigma(8)\rvert$ …(11)	106.47	226.98	361.12	505.81	661.82

343. In my Draft Decision, I addressed three matters in relation to the Depreciation Schedule proposed by Epic Energy, concluding that:

- the asset lives assumed by Epic Energy for depreciation purposes are excessively long and should be revised to be consistent with common industry assumptions for gas transmission pipelines (70 years for pipelines, 30 years for compression assets, 50 years for metering assets and 30 years for other depreciable assets);
- the annuity method of depreciation is consistent with the principles set out in the Code for a Depreciation Schedule; and
- for the DBNGP at present, there is no reasonable justification for economic depreciation (as defined by Epic Energy) with deferred recovery of capital costs so as to accommodate a higher value of the Initial Capital Base.

economic depreciation to be calculated as forecast revenue minus the sum of physical asset depreciation, return on the Capital Base, and Non Capital Costs. (Epic Energy, response to Information Request 6: Application of the Brattle Group Regulatory Model 24 November 2000.)

344. In submissions made to me subsequent to issue of the Draft Decision, Epic Energy reiterated the reasons for the proposed depreciation schedule as put to me in submissions prior to the Draft Decision. Epic Energy again indicated that precedents exist for use of deferred depreciation in situations where growth in the market for services is expected, with particular reference to the Central West Pipeline in New South Wales and the SITCO Pipeline in the USA.

345. On the basis of the information provided to me by Epic Energy, I consider that the additional example of the SITCO pipeline referred to by Epic Energy is an example of application of a deferred recovery scheme similar to the Central West Pipeline in NSW, wherein a pipeline is constructed to a capacity that is in excess of immediate requirements, but a regulated tariff is established that is less than would be justifiable on a cost-of-service basis. “Losses” resulting from the under-recovery of construction costs are capitalised with a view to recovery in the future when demand for pipeline services is greater. Both of the examples cited by Epic Energy reflect situations of pipelines that are different to the situation of the DBNGP, which is operating at close to full capacity, and for which the proposed system of deferred recovery is intended to provide a mechanism of recovering a purchase cost well in excess of construction costs.

346. I maintain my view as expressed in the Draft Decision that I see no in-principle justification for deferred recovery of capital costs in the situation of the DBNGP.

Non Capital Costs

347. Sections 8.36 and 8.37 of the Code provide for the recovery of Non Capital Costs through the Reference Tariff:

> 8.36 Non Capital Costs are the operating, maintenance and other costs incurred in the delivery of the Reference Service.
>
> 8.37 A Reference Tariff may provide for the recovery of all Non Capital Costs (or forecast Non Capital Costs, as relevant) except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service.

348. Epic Energy forecast Non Capital Costs for the Access Arrangement Period as follows (converted to real 31 December 1999 dollar values).

Epic Energy forecast Non Capital Costs (1999 $million, year ending 31 December)

Type of Investment	2000	2001	2002	2003	2004	Total
Wages and salaries	9.68	9.68	9.68	9.68	9.68	48.38
Materials and services	10.58	11.29	13.18	12.82	12.23	60.09
Property taxes	0.05	0.05	0.05	0.05	0.05	0.25
Marketing	0.44	0.44	0.44	0.44	0.44	2.19
Corporate overheads	3.85	3.75	3.91	3.87	3.80	19.18
Gas used in operations	13.56	14.09	14.30	14.95	15.20	72.10
Total	**38.15**	**39.29**	**41.55**	**41.80**	**41.40**	**202.18**

349. In my Draft Decision, I gave specific attention to components of Non Capital Costs – including compressor fuel costs, corporate overhead costs and marketing costs – and to time trends in total non-capital costs. I took the view in the Draft Decision that cost forecasts have not been substantiated or supported sufficiently to indicate that the forecast costs are consistent with the requirements of section 8.37 of the Code, that is, sufficient to demonstrate that the costs are consistent with those that would be incurred by a prudent operator, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service. However, I considered that while the cost forecasts are inadequately substantiated, there is insufficient technical justification at the current time to seek amendment of these costs. I have no new information that would cause me to change this view. However, after consideration of proposed New Facilities Investment (paragraphs 290 to 308 of this Final Decision), I am of the view that some costs proposed by Epic Energy in relation to forecast New Facilities Investment should be considered for the purposes of the Access Arrangement as Non Capital Costs, and the forecasts of capital costs and Non Capital Costs should be amended to refect this. The revised forecasts of Non Capital Costs are as follows (31 December 1999 $million).

Year ending 31 December	2000	2001	2002	2003	2004	Total
Total Non Capital Costs	38.41	39.58	41.83	42.09	41.65	203.56

350. In my Draft Decision, I also addressed other matters related to Non Capital Costs including provision for Users to supply their own fuel gas in lieu of payment of a fuel gas charge, and requirement for Epic Energy to provide information on performance indicators that would be of use in assessing proposed Non Capital Costs.

351. Under the proposed Access Arrangement, Users would not be able to supply their own fuel gas, but rather would meet the costs of fuel gas through Epic Energy's proposed compressor fuel charge that is one of the charges making up the Reference Tariff. Epic Energy indicated to me that the proposal to not allow Users to provide gas in lieu of paying a compression fuel charge is a result of Epic Energy being bound by long-term contracts for purchase of gas, including a contract with AlintaGas entered into prior to Epic Energy assuming ownership of the DBNGP. Epic Energy indicated that as a result of the contractual commitments, it would not be able to contemplate Users providing gas prior to at least 2005.[113]

352. I took the view in my Draft Decision that, given the contractual commitments of Epic Energy, it would not be appropriate to require that Epic Energy make provision in the current Access Arrangement Period for Users to supply their own fuel gas, but that Users should have the option to supply fuel gas in lieu of paying the Compressor Fuel Charge after expiry of Epic Energy's current contracts for purchase of gas for this purpose.

353. Epic Energy has subsequently made a submission to me objecting to a requirement to amend the Access Arrangement to allow Users to supply their own fuel gas, indicating that the matter should be deferred to subsequent review of the Access Arrangement so

[113] Epic Energy (WA) Transmission Pty Ltd, 16 March 2001, Proposed Access Arrangement under the National Access Code, Information Request 17: System Use Gas.

that Epic Energy's negotiating position with gas suppliers is not compromised, and to allow consideration of whether Users in general will benefit from being allowed to provide their own fuel gas, or whether the benefits will flow to a few Users leaving others to pay higher prices either through their own gas purchase contracts, or through a contract for a diminished quantity of gas negotiated by Epic Energy.

354. After consideration of Epic Energy's submission, and recognising the current contractual commitments of Epic Energy to purchase fuel gas, I concur with Epic Energy that provision for Users to supply their own fuel gas should be a matter considered in relation to the next Access Arrangement Period.

355. In my Draft Decision, I indicated that the Access Arrangement Information should be amended to include information on key performance indicators. On further consideration of this issue, I consider that this requirement would be of limited value for the assessment of the proposed Access Arrangement. I would expect, however, that such information would be considered in respect of revisions to the Access Arrangement and prior to the next Access Arrangement Period and in this regard performance indicators would be developed in consultation with Epic Energy.

356. In regard to Non Capital Costs I have also given consideration to the extent to which, and manner by which, costs associated with regulation under the Code may be recovered through regulated tariffs.

357. The Gas Pipelines Access legislation provides a user-pays system of regulation so that the costs of regulation are borne by the Users of the pipeline who benefit from the regulation.

358. The *Gas Pipelines Access (Western Australia) (Funding) Regulations 1999* (WA) provide for the Regulator's costs to be charged to pipeline owners. However, the user-pays system will only be carried into effect if the costs of regulation form part of the operating costs to be considered in approving an access arrangement.

359. In response to my request for submissions from Epic Energy as to how additional regulation costs associated with this access arrangement should be dealt with in the access arrangement, Epic Energy has submitted that it should be able to recover all costs of regulation from Users as Non Capital Costs by means of a separate charge in the Reference Tariff calculation rather than such costs being incorporated into the Pipeline Commodity Charge. Epic Energy has made an alternative submission that, if I choose to incorporate the costs of regulation into the Pipeline Commodity Charge, then I should increase Epic Energy's current assessment of Non Capital Costs to take into account the costs of regulation to date, future costs of regulation and all Epic Energy's costs in connection with the regulatory process. Epic Energy has submitted that there has been a substantial increase in its non-capital costs by reason of the increased costs of regulation.

360. The current Access Arrangement period commenced on 1 January 2000 and is due to expire on 31 December 2004. As such, Epic Energy has recognised the potential for some Users to be disadvantaged if all of the increased costs of regulation are passed on to existing users in the current Access Arrangement Period. Therefore, Epic Energy has sought to pass on the uncharged increased costs of regulation over into the next Access Arrangement Period.

361. I am conscious of the need to ensure that any approach to allowing the recovery of regulatory costs is consistent with objectives of the Code that require fairness for pipeline operators, the need to ensure equitable allocation of costs between Users of pipeline services, the need to ensure that costs are not allocated in a way that leads to inefficiencies and the need to provide incentives to reduce costs, including the costs associated with the regulatory process.

362. I note that this is a new issue which has not been the subject of submissions from Users. Subsequent to an invitation from me, Epic Energy made submissions on 16 and 19 May 2003. Further, given the uncertainty about the precise quantum and timing of passing these costs to Users, I have decided not to allow Epic Energy to pass on these increased costs of regulation to Users during the period of this Access Arrangement. However I consider that these increased costs, together with any appropriate interest component, may be appropriate for Epic Energy to seek to recover the next Access Arrangement.

363. In the circumstances, I accept the submission of Epic Energy that it is appropriate for the regulatory costs associated with the Access Arrangement (including interest on those costs that have been paid by Epic Energy) to be considered as part of the next Access Arrangement. At that time I will receive submissions from all interested parties as to the quantum of these costs that Epic Energy should be allowed to recover and the manner in which recovery of such costs should be provided for in the Access Arrangement.

Total Revenue

364. Sections 8.4 and 8.5 of the Code require that the revenue to be generated from the sales (or forecast sales) of all services over the Access Arrangement Period (the Total Revenue) be determined, or be able to be expressed in terms of, one of three methodologies.

> Cost of Service: the Total Revenue is equal to the cost of providing all services (some of which may be the forecast of such costs), and with this cost to be calculated on the basis of:
>
> (a) a return (Rate of Return) on the value of the capital assets that form the Covered Pipeline or are otherwise used to provide Services (Capital Base);
>
> (b) depreciation of the Capital Base (depreciation); and
>
> (c) the operating, maintenance and other non-capital costs incurred in providing all Services provided by the Covered Pipeline (Non Capital Costs).
>
> Internal Rate of Return (IRR): the Total Revenue will provide a forecast IRR for the Covered Pipeline that is consistent with the principles in sections 8.30 and 8.31 of the Code. The IRR should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period. The initial value of the Covered Pipeline in the IRR calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed residual value of the Covered Pipeline at the end of the Access Arrangement Period (Residual Value) should be calculated consistently with the principles in section 8 of the Code.
>
> Net Present Value (NPV): the Total Revenue will provide a forecast NPV for the Covered Pipeline equal to zero. The NPV should be calculated on the basis of a forecast of all costs to be incurred in providing such services (including capital costs) during the Access Arrangement Period, and using a discount rate that would provide the Service Provider with a return consistent with the principles in sections 8.30 and 8.31 of the Code. The initial value of the Covered Pipeline in the NPV

> calculation is to be given by the Capital Base at the commencement of the Access Arrangement Period and the assumed Residual Value at the end of the Access Arrangement Period should be calculated consistently with the principles in section 8 of the Code.
>
> The methodology used to calculate the Cost of Service, an IRR or NPV should be in accordance with generally accepted industry practice.
>
> However, the methodology used to calculate the Cost of Service, an IRR or NPV may also allow the Service Provider to retain some or all of the benefits arising from efficiency gains under an Incentive Mechanism. The amount of the benefit will be determined by the Relevant Regulator in the range of between 100% and 0% of the total efficiency gains achieved.

365. Section 8.6 of the Code recognises that a range of values may be attributed to the Total Revenue by the above methodologies. This gives recognition to the manner in which the Rate of Return, Capital Base, Depreciation Schedule and Non Capital Costs may be determined, in each case involving the exercise of my discretion.

366. In order to determine an appropriate value within this range, the Regulator may have regard to any financial and operational performance indicators considered by the Regulator to be relevant in order to determine the level of costs within the range of feasible outcomes under section 8.4 of the Code that is most consistent with the objectives contained in section 8.1 of the Code. Section 8.7 of the Code requires that, if the Regulator has considered financial and operational performance indicators for the purposes of section 8.6 of the Code, it must identify the indicators and provide an explanation of how they have been taken into account.

367. Epic Energy has determined a Total Revenue requirement using the "cost of service" methodology described in section 8.4 of the Code. The forecast total costs of providing services are indicated in Table 2.2 of the Access Arrangement Information, as follows.

Epic Energy forecast total costs of providing services (nominal $million, year ending 31 December)

	2000	2001	2002	2003	2004
Return on Capital Base					
Physical asset account					
Pipeline	235.89	235.94	235.97	235.99	236.04
Compressor stations	39.51	41.80	42.27	42.75	42.93
Metering assets	3.24	3.24	3.25	3.25	3.26
Other assets	9.55	10.15	10.76	11.47	12.07
Deferred recovery account	0.00	14.89	29.88	46.68	64.46
Depreciation					
Physical asset account					
Pipeline assets	0.03	0.03	0.04	0.04	0.05
Compressor stations	0.32	0.36	0.40	0.45	0.50
Metering assets	0.01	0.01	0.01	0.01	0.01
Other assets	0.03	0.04	0.05	0.06	0.06
Non Capital Costs					
Pipeline maintenance	10.64	10.49	10.77	11.08	11.43
Compressor maintenance	3.63	3.73	5.83	6.39	5.77
Compressor fuel	13.05	13.95	14.28	15.47	16.34
Other costs	11.80	13.11	13.85	13.20	13.29
Total	**327.70**	**347.74**	**367.36**	**386.83**	**406.20**

368. In my Draft Decision, I observed that the Total Revenue for the DBNGP indicated by Epic Energy reflects provision for deferred recovery of capital costs, involving credit to a deferred recovery account of the value of any deficit of forecast actual revenue (given the proposed Reference Tariff) under the total cost of service provision. The balance of the deferred recovery account constitutes part of the Capital Base, and a return on the balance of the deferred recovery account comprises part of the Total Revenue requirement.

369. By including in Total Revenue the cost of a return on the balance of the deferred recovery account, Epic Energy has not provided an indication of the total cost of service provision that would be derived in a more conventional cost-of-service approach to determination of Total Revenue. The Total Revenue requirement consistent with Epic Energy's assumptions and calculations for Reference Tariffs, but without deferred depreciation or the cost of a return on the balance of the deferred recovery account, is as follows.

Epic Energy forecast total costs of providing services, without costs of deferred depreciation (nominal $million, year ending 31 December)

	2000	2001	2002	2003	2004
Return on Capital Base					
Physical asset account					
Pipeline	235.89	235.94	235.97	235.99	236.04
Compressor stations	39.51	41.80	42.27	42.75	42.93
Metering assets	3.24	3.24	3.25	3.25	3.26
Other assets	9.55	10.15	10.76	11.47	12.07
Depreciation					
Physical asset account					
Pipeline assets	0.03	0.03	0.04	0.04	0.05
Compressor stations	0.32	0.36	0.40	0.45	0.50
Metering assets	0.01	0.01	0.01	0.01	0.01
Other assets	0.03	0.04	0.05	0.06	0.06
Non Capital Costs					
Pipeline maintenance	10.64	10.49	10.77	11.08	11.43
Compressor maintenance	3.63	3.73	5.83	6.39	5.77
Compressor fuel	13.05	13.95	14.28	15.47	16.34
Other costs	11.80	13.11	13.85	13.20	13.29
Total	**327.70**	**332.85**	**337.48**	**340.15**	**341.74**

370. The Total Revenue projected for the pipeline in the Access Arrangement Period will be affected by the value of the Initial Capital Base. I therefore return to consideration of the Total Revenue later in this Final Decision when I further consider the Initial Capital Base.

Cost/Revenue Allocation and the Reference Tariff

371. In determining Reference Tariffs, a Service Provider must determine (explicitly or implicitly) the costs or share of costs of pipeline operation that will be recovered from revenues from Reference Services and other services. Rules for the allocation of costs/revenues between services are provided in sections 8.38 to 8.43 of the Code.

372. Section 8.38 of the Code requires that Reference Tariffs should be designed to only recover that portion of Total Revenue which includes:

(a) all of the Total Revenue that reflects costs incurred (including capital costs) that are directly attributable to the Reference Service; and

(b) a share of the Total Revenue that reflects costs incurred (including capital costs) that are attributable to providing the Reference Service jointly with other Services, with this share to be determined in accordance with a methodology that meets the objectives set out in section 8.1 of the Code and is otherwise fair and reasonable.

373. Section 8.39 of the Code provides for the Regulator to require a different methodology to be used for cost/revenue allocation than may have been proposed by a Service Provider in an Access Arrangement pursuant to section 8.38 of the Code. However, if such a requirement is proposed, the Regulator must provide a detailed explanation of the methodology that is required to be used.

374. Section 8.40 of the Code addresses the allocation of Costs/Revenue between Reference Services and Rebatable Services. A Rebatable Service occurs where a

portion of any revenue realised from sales of service is rebated to Users (either through a reduction in the tariff or through a direct rebate to the relevant User or Users). Under section 10.8 of the Code, a Rebatable Service is a service where:

(a) there is substantial uncertainty regarding expected future revenue from sales of that Service due to the nature of the Service and/or the market for that Service; and

(b) the nature of the Service and the market for that Service is substantially different to any Reference Service and the market for that Reference Service.

375. If a Reference Service is provided jointly with a Rebatable Service, then all or part of the Total Revenue that would have been recovered from the Rebatable Service under section 8.38 of the Code (if that service was a Reference Service) may be recovered from the Reference Service provided that an appropriate portion of any revenue realised from sales of any such Rebatable Service is rebated to Users of the Reference Service (either through a reduction in the Reference Tariff or through a direct rebate to the relevant User or Users). The structure of such a rebate mechanism should be determined having regard to the following objectives:

(a) providing the Service Provider with an incentive to promote the efficient use of capacity, including through the sale of Rebatable Services; and

(b) Users of the Reference Service sharing in the gains from additional sales of services, including from sales of Rebatable Services.

376. Section 8.41 provides a Service Provider with discretion to adopt alternative approaches to cost/revenue allocation subject to any approach adopted having substantially the same effect as the approach outlined in section 8.38 and 8.40 of the Code.

377. Section 8.42 relates to the allocation of costs/revenue between Users. This section requires that, subject to provisions for prudent discounts in section 8.43 of the Code, the Reference Tariff be designed such that the proportion of Total Revenue recovered from actual or forecast sales of a Reference Service to a particular User of that service is consistent with the principles described in section 8.38 of the Code.

378. Section 8.43 of the Code provides for a Service Provider to give prudent discounts on Reference Tariffs or Equivalent Tariffs for Non-Reference Services in particular circumstances. A User receiving a discount would be paying a proportion of Total Revenue that is less than the proportion that would be paid by the User under the principles of sections 8.38 and 8.40 of the Code. Section 8.43 of the Code provides for such a discount to be given to a User if:

(a) the nature of the market in which a User or Prospective User of a Reference Service or some other Service operates, or the price of alternative fuels available to such a User or Prospective User, is such that the Service, if priced at the nearest Reference Tariff (or, if the Service is not a Reference Service, at the Equivalent Tariff) would not be used by that User or Prospective User; and

(b) a Reference Tariff (or Equivalent Tariff) calculated without regard to revenues from that User or Prospective User would be greater than the Reference Tariff (or Equivalent Tariff) if calculated having regard to revenues received from that User or Prospective User on the basis that it is served at a price less than the Reference Tariff (or Equivalent Tariff).

379. The effect of section 8.43(b) is to require that a discount may only be provided to a User if the incremental revenue from that User exceeds the incremental cost of

providing a service to that User, and hence the incremental revenue still makes some contribution to the joint costs of providing pipeline services. The proportion of Total Revenue that comprises the discount may be recovered from other Users of the Reference Service or some other service or services in a manner that the Regulator is satisfied is fair and reasonable.

380. The cost-allocation methodology used by Epic Energy in determining the Reference Tariff is described in section 2.4 of the Access Arrangement Information.

381. For the purposes of determining the Reference Tariff, Epic Energy assumed that the total costs of providing services (i.e. Total Revenue) would be recovered from Users of firm capacity as if those Users are users of the Reference Service that pay the Reference Tariff. No costs were allocated to Non-Reference Services, some of which are proposed to be treated as Rebatable Services.

382. The Reference Tariff proposed by Epic Energy comprises multiple charges:

- Pipeline Capacity Charge;
- Compression Capacity Charge;
- Compressor Fuel Charge;
- Gas Receipt Charge; and
- Delivery Point Charge.

383. In developing a Reference Tariff, components of the total cost of providing services in the first year of the Access Arrangement Period (2000) were allocated to various charges that make up the Reference Tariff. The allocation was determined so that a User pays a share of total costs reflecting pipeline assets used and the costs incurred in providing the service to the User. The basis for allocation of forecast total costs to charges is described in Table 2.3 of the Access Arrangement Information and interpreted by the Regulator as follows.

Epic Energy proposed cost allocation to Reference Tariff charges

Reference Tariff Charge	Costs Recovered	Basis of Charge
Pipeline Capacity Charge	Return on pipeline asset value by pipeline zone. Depreciation of pipeline asset value by pipeline zone. Pipeline maintenance costs by pipeline zone.	Charge per unit of contracted MDQ in each zone.
Compression Capacity Charge	Return on compressor station asset value for each compressor station. Depreciation of compressor station asset value for each compressor station. Compressor station maintenance costs for each compressor station.	Charge per unit of contracted MDQ transported to pipeline downstream of the relevant compressor station.
Compressor Fuel Charge	Compressor fuel costs for each compressor station.	Charge per unit of gas throughput transported to pipeline downstream of the relevant compressor station.
Gas Receipt Charge	Return on asset value for "other" assets. Depreciation of asset value for "other" assets. Non Capital Costs other than pipeline and compressor station maintenance costs.	Charge per unit of contracted Delivery Point MDQ.
Delivery Point Charge	Return on asset value for metering assets at Delivery Points. Depreciation of asset value for metering assets at Delivery Points.	Fixed charge for each Delivery Point.

384. The allocation of costs to charges of the Reference Tariff arises from an attribution of the Initial Capital Base, Capital Expenditure and Non Capital Costs to particular assets or activities and to particular zones of the Pipeline. Consequently, costs of return on capital, depreciation and the Non Capital Costs are attributed to particular zones of the pipeline and particular assets. Epic Energy has indicated that this attribution of costs allows charges to be set to recover costs from Users according to the parts of the DBNGP nominally utilised by each User. Accordingly, Epic Energy has described each charge as follows.

- The Pipeline Capacity Charge is payable for each zone between a Shipper's Receipt Point and Delivery Point (including the zones in which the Receipt Point and Delivery Point are located).
- The Compression Capacity Charge is payable by a Shipper for each compressor station located between the Shipper's Receipt Point and Delivery Point.
- The Compressor Fuel Charge is payable by a Shipper in respect of each compressor station located between the Shipper's Receipt Point and Delivery Point.
- The Gas Receipt Charge is a fixed charge payable by each Shipper in respect of costs not assigned to sections of the pipeline or particular assets.

- The Delivery Point Charge is a fixed charge in respect of costs assigned to assets of Delivery Point facilities.

385. Epic Energy's proposed Total Revenue requirement would, in the absence of any deferred recovery of revenue, give rise to total tariffs (at 100 percent load factor) of $1.41/GJ for delivery from Zone 1a to Zone 9, and $1.62/GJ for delivery from Zone 1a to Zone 10. The Delivery Point Charge would be additional to these tariffs. On the basis of throughput forecasts for the Access Arrangement Period, the average value of the Delivery Point Charge across Users would be 8.2 cents per gigajoule, although this would vary between 0.3 cents and 34.8 cents per gigajoule. The Reference Tariff charges would be as follows.[114]

Proposed Pipeline Capacity Charges ($/GJ MDQ)
Gas Receipt Point Located in Zone 1a or Zone 1b

Delivery point located in:

Zone 1a	Zone 1b	Zone 2	Zone3	Zone4	Zone 4a	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
0.0181	0.2272	0.3236	0.4185	0.5137	15.799	0.6106	0.7086	0.8220	0.9264	1.0657	1.2615

Compression Capacity Charges Derived from Epic Energy 2000 Total Revenue ($/GJ MDQ)

Delivery point located between:

Dampier & Zone 1a	Zone 1a & CS2	CS2 & CS3	CS3 & CS4	CS4 & CS5	CS5 & CS6	CS6 & CS7	CS7 & CS8	CS8 & CS9	CS9 & CS10	CS10 & MLV157
0.0000	0.0000	0.0000	0.0268	0.0422	0.0762	0.1056	0.1205	0.1488	0.1799	0.1904

Compressor Fuel Charges Derived from Epic Energy 2000 Total Revenue ($/GJ throughput)

Delivery point located between:

Dampier & Zone 1a	Zone 1a & CS2	CS2 & CS3	CS3 & CS4	CS4 & CS5	CS5 & CS6	CS6 & CS7	CS7 & CS8	CS8 & CS9	CS9 & CS10	CS10 & MLV157
0.0000	0.0145	0.0145	0.0221	0.0297	0.0374	0.0450	0.0527	0.0606	0.0685	0.0718

Gas Receipt Charge Derived from Epic Energy 2000 Total Revenue ($/GJ MDQ)

Delivery point located in:

Zone 1a	Zone 1b	Zone 2	Zone 3	Zone 4	Zone 4a	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985	0.0985

[114] Determined using a tariff model provided to the Regulator by Epic Energy.

Delivery Point Charge Derived from Epic Energy 2000 Total Revenue ($/day)

Delivery Zone	Delivery Point	Charge
Zone 1a	Hamersley Iron	303.36
	Robe River	193.57
Zone 4	Carnarvon	177.77
Zone 7	Geraldton (Nangetty Road)	167.68
	Eradu Road	136.10
	Mungarra	263.27
	Pye Road	165.96
	Mondarra	152.11
	Mount Adams Road	161.65
	Eneabba	174.17
Zone 9	Muchea	219.80
	Della Road	117.81
	Pinjar	676.79
	Ellenbrook	153.66
	Harrow Street	237.03
	Caversham	171.15
	Welshpool	255.72
	Forrestdale	255.72
	Russell Road	171.03
Zone 10	Wesfarmers LPG	0.00
	Australian Gold Reagents	144.72
	Alcoa Kwinana	415.20
	Kwinana Power Station	758.51
	Barter Road/HiSmelt	329.18
	Mission Energy Cogeneration	143.48
	Thomas Road	222.35
	Kwinana Beach Road	184.94
	WMC	148.38
	Rockingham	167.31
	Pinjarra	165.70
	Alcoa Pinjarra	543.18
	Oakley Road	143.00
	Alcoa Wagerup	382.63
	Harvey	179.26
	Worsley	358.54
	South West Cogeneration	118.59
	Kemerton	156.83
	Clifton Road	179.43

386. Epic Energy has noted in section 2.5 of the Access Arrangement Information that a Reference Tariff derived from the forecast total costs of services (Total Revenue) would be significantly higher than the gas transmission tariffs to which Epic Energy purportedly gave a commitment to implementing in Schedule 39 of the DBNGP Asset Sale Agreement, that is, $1.00/GJ to Kwinana Junction and a greater tariff for Delivery Points downstream of Kwinana Junction. Epic Energy goes on to indicate that in order to satisfy commitments that it made at the time the DBNGP was sold, pro-rata adjustments were made to the charges, other than the Delivery Point Charge, to derive a Reference Tariff with the following attributes.

- for gas transportation from a Receipt Point in Zone 1 to a Delivery Point in Zone 9 (for a Shipper with a load factor of 100 percent), the aggregate of the tariff components excluding the Delivery Point charge, is $1.00/GJ as at 1 January 2000; and

- for gas transportation from a Receipt Point in Zone 1 to a Delivery Point in Zone 10 (for a Shipper with a load factor of 100 percent), the aggregate of the tariff components excluding the Delivery Point charge is $1.08/GJ as at 1 January 2000.

387. The tariff adjustments were made by multiplying the Pipeline Capacity Charges, Compression Capacity Charges, Compressor Fuel Charges and Gas Receipt Charges derived from the total cost of services by the following scaling factors.

- Charges for Zones 1 to 9 – scaling factor of 0.7078
- Charges for Zone 10 – scaling factor of 0.3817.

388. The adjusted charges of Epic Energy's proposed Reference Tariff are as follows.

Pipeline Capacity Charges Derived from Epic Energy 2000 Total Revenue ($/GJ MDQ)
Gas Receipt Point Located in Zone 1a or Zone 1b

Delivery point located in:

Zone 1a	Zone 1b	Zone 2	Zone 3	Zone 4	Zone 4a	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
0.0129	0.1610	0.2292	0.2965	0.3639	11.1924	0.4326	0.5020	0.5816	0.6556	0.7543	0.8290

Compression Capacity Charges Derived from Epic Energy 2000 Total Revenue ($/GJ MDQ)

Delivery point located between:

Dampier & Zone 1a	Zone 1a & CS2	CS2 & CS3	CS3 & CS4	CS4 & CS5	CS5 & CS6	CS6 & CS7	CS7 & CS8	CS8 & CS9	CS9 & CS10	CS10 & MLV157
0.0000	0.0000	0.0000	0.0190	0.0299	0.0540	0.0748	0.0854	0.1054	0.1274	0.1314

Compressor Fuel Charges Derived from Epic Energy 2000 Total Revenue ($/GJ)

Delivery point located between:

Dampier & Zone 1a	Zone 1a & CS2	CS2 & CS3	CS3 & CS4	CS4 & CS5	CS5 & CS6	CS6 & CS7	CS7 & CS8	CS8 & CS9	CS9 & CS10	CS10 & MLV157
0.0000	0.0103	0.0103	0.0157	0.0211	0.0265	0.0319	0.0373	0.0429	0.0486	0.0498

Gas Receipt Charge Derived from Epic Energy 2000 Total Revenue ($/GJ MDQ)

Delivery point located in:

Zone 1a	Zone 1b	Zone 2	Zone 3	Zone 4	Zone 4a	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698	0.0698

389. In section 9 of the proposed Access Arrangement, Epic Energy has proposed that some Non-Reference Services be Rebatable Services. The Non-Reference Services that are to be Rebatable Services are indicated in section 9.1 of the proposed Access Arrangement to be the Seasonal Service, the Park and Loan Service, the Secondary Market Service and any other service nominated by Epic Energy. Additionally, Epic Energy has also proposed that revenue (less the Compressor Fuel Charge) obtained by

Epic Energy from Overrun charges under sub-clause 5.2 of the Access Contract Terms and Conditions is Rebatable Revenue.

390. Section 9.2(a) of the proposed Access Arrangement sets out a mechanism for determining an amount of the Rebatable Revenue that is "Distributable Revenue". Subsequent to submission of the proposed Access Arrangement, Epic Energy advised the Regulator that the mechanism set out in section 9 of the proposed Access Arrangement was in need of revision, and submitted a revised, although similar, specification of the mechanism.[115] This is set out as follows.

> The Distributable Revenue for a year is defined as the amount by which the Rebateable Revenue for that year exceeds the sum of:
>
> - the difference between that part of Total Revenue attributable to the provision of Firm Service and actual revenue from the sale of Firm Service;
> - the difference between forecast revenue from Shippers with Prior Contracts and actual revenue from Shippers with Prior Contracts; and
> - the costs of providing the services from which the Rebateable Revenue was obtained.
>
> The Distributable Revenue ("DR") is then:
>
> $$\begin{aligned} DR &= RR - [(TRFS - RFS) + (FPR - PR) + r \times Q] \\ &= RR - (TRFS - RFS + r \times Q) - FPR + PR \\ &= (RR + PR) - (TR + FPR) \end{aligned}$$
>
> where:
>
> RR = Rebateable Revenue;
>
> TR = TRFS – RFS + r x Q, is Threshold Revenue (the amount by which actual revenue from the sale of Firm Service (RFS) falls short of that component of Total Revenue attributable to the provision of Firm Service (TRFS), plus the cost of providing those services from which Rebateable Revenue was obtained (r x Q));
>
> FPR = forecast revenue from Shippers with Prior Contracts; and
>
> PR = actual revenue from Shippers with Prior Contracts.
>
> The amount by which actual revenue from the sale of Firm Service (RFS) falls short of that component of Total Revenue attributable to the provision of Firm Service (TRFS) is approximately equal to:
>
> $$a_1 \times (FSC - PAC) \times C_1 + a_2 \times (FSV - PAV) \times C_2 - RFS + r \times Q$$
>
> where:
>
> a_1 = forecast average revenue from capacity related charges (Gas Receipt Charge, Pipeline Capacity Charge, and Compression Capacity Charge) for Firm Service in the first year of the proposed Access Arrangement; and
>
> a_2 = forecast average revenue from the Compressor Fuel Charge for Firm Service in the first year of the proposed Access Arrangement.
>
> FSC = forecast of contracted capacity for the year used in the modelling to support determination of the proposed DBNGP Reference Tariff assuming all T1 and T2 (full

[115] Epic Energy (WA) Transmission Pty Ltd,, 31 January 2001, Additional Paper 6: Rebateable Revenue.

haul and part haul) Shippers, and Alcoa, are Firm Service Shippers, as set out in the table of paragraph 9.2(a) of the proposed Access Arrangement;

C_1 = sum of Zone 10 Gas Receipt Charge, Pipeline Capacity Charge and Compression Capacity Charge rates for the Year (that is, the sum of the Zone 10 Capacity Charge rates as escalated from year to year in accordance with the Reference Tariff Policy of the proposed Access Arrangement);

FSV = volume of throughput forecast for the Year used in the modelling to support determination of the proposed DBNGP Reference Tariff assuming all T1 and T2 (full haul and part haul) Shippers, and Alcoa, are Firm Service Shippers, as set out in the table of paragraph 9.2(a) of the proposed Access Arrangement;

C2 = Compressor Fuel Charge rate for a Delivery Point located between Compressor Station 10 and MLV 157A for the year (that is, the Compressor Fuel Charge rate as escalated from year to year in accordance with the Reference Tariff Policy of the proposed Access Arrangement);

PAC = capacity contracted to Shippers under Prior Contracts (other than the Alcoa of Australia Exempt Contract) for the year, plus the use of capacity in the year made by Alcoa of Australia under the Exempt Contract); and

PAV = volume delivered to Shippers under Prior Contracts.

The cost of providing the services from which Rebateable Revenue was obtained is the product of:

r = the marginal cost of delivering additional volume (the principal components of which will be a loss in per unit revenue under the Alcoa Exempt Contract, and the cost of additional comp ressor fuel); and

Q = the volume delivered via services from which Rebateable Revenue was obtained.

Both a_1 and a_2 are determined from the modelling which supports determination of the proposed DBNGP Reference Tariff. Their values are:

Parameter	Value
a_1	0.903292359
a_2	0.902369200

391. Section 9.2(b) of the proposed Access Arrangement sets out a proportional distribution of distributable revenue as follows.

Where DR is greater than zero, then the amount of Rebatable Revenue equal to DR shall be distributed as follows:

- 45% is to be distributed to Rebate Sharing Shippers during the year;
- 40% is added to the deferred recovery account balance as described in Paragraph 7.3 of the proposed Access Arrangement;[116] and
- 15% is to be retained by Epic Energy.

If DR is less than or equal to zero, the Rebateable Revenue is to be retained by Epic Energy.

392. In assessing the proposed allocation of Total Revenue and the proposed Reference Tariff for the purposes of the Draft Decision, I considered the following issues.

[116] For clarification, additions of positive sums to the deferred recovery account act to reduce the "negative balance" of the account.

- Allocation of costs between services.
- The zonal tariff structure and allocation of costs to pipeline zones.
- Forecast gas throughput for the DBNGP over the Access Arrangement Period.
- The magnitude of the Reference Tariff.
- The charge structure of the Reference Tariff and allocation of costs to individual charges.
- The method of adjustment of the cost-based tariffs (i.e. tariffs that would be derived from the calculated Total Revenue) to the proposed Reference Tariff.
- Requirements for payment of charges in advance of receiving services.
- Prudent discounts to the Reference Tariff.
- Rebatable services.

393. I have given further consideration to each of these matters subsequent to the Draft Decision and taking into account submissions that I have received. My deliberations and conclusions on each of these matters are summarised as follows.

394. In regard to allocation of costs between services, Epic Energy has adopted an assumption that all gas throughput for the Access Arrangement Period occurs under the proposed Reference Service (the Firm Service). In considering this basis for allocation of costs, I took into account the requirements of section 8.38 of the Code, which requires that the portion of Total Revenue that a Reference Tariff is designed to recover should include all of the Total Revenue that reflects costs directly attributable to the Reference Service, and a share of the Total Revenue that reflects costs attributable to the Reference Service jointly with other services. There is no reason to assume that the costs directly attributable to providing the Reference Service, or the share of joint costs attributable to the Reference Service should be materially different on a per unit basis from services provided under contracts entered into under the *Gas Transmission Regulations 1994*, *Dampier to Bunbury Pipeline Regulations 1998* or the Alcoa contract. I therefore took the view that an assumption that all forecast throughput occurs under the proposed Reference Service is a reasonable basis for cost allocation and meets the requirements of the Code.

395. In response to submissions, I also noted in the Draft Decision that it is neither necessary nor appropriate in determining a cost allocation to consider the expected revenue to be received from gas transmission under existing contracts. The purpose of doing so would be, supposedly, to set a Reference Tariff to recover the difference between revenue gained from existing contracts and the required Total Revenue. Such an approach would have the effect of rewarding the Service Provider if the tariffs for existing contracts are less than the tariff that would be determined if costs were allocated evenly across existing contracts and the Reference Service, and penalising the Service Provider if the reverse is true. In the first case this could penalise new Users, and in the second case may have the effect of depriving the Service Provider of a contractual right (to obtain revenue) that was in existence prior

to the date of the proposed Access Arrangement, which would be contrary to the provisions of section 2.25 of the Code.

396. In regard to the zonal structure of the Reference Tariff, Epic Energy's proposed Reference Tariff includes three charges that are to be levied on a quasi-distance basis:

- the Pipeline Capacity Charge, that is payable for each pipeline zone between a Shipper's Receipt Point and Delivery Point (including the zones in which the Receipt Point and Delivery Point are located);

- the Compression Capacity Charge, that is payable by a Shipper for each compressor station (other than Compressor Stations 1 and 2) located between the Shipper's Receipt Point and Delivery Point; and

- the Compressor Fuel Charge, that is payable by a Shipper in respect of each compressor station (other than Compressor Stations 1 and 2) located between the Shipper's Receipt Point and Delivery Point.

397. In actual determination of the Reference Tariff and specification of the Reference Tariff Policy in the proposed Access Arrangement, Epic Energy has proposed in the text of the Access Arrangement Information that compression charges be determined on a "pass through" basis such that a User only pays compression charges relating to compressors between the User's Receipt Point and Delivery Point.[117] However, in the actual determination of the Reference Tariffs and specification of the Reference Tariff in the proposed Access Arrangement (as opposed to the description of tariff charges in the Access Arrangement Information), Epic Energy has determined the Compression Capacity Charge and the Compressor Fuel Charge on the basis of the pipeline zones rather than, as stated in the Access Arrangement Information, on the basis of the compressor stations between a User's Receipt Point and Delivery Point. With current locations of Receipt Points and Delivery Points, the results of this are:

- Users with Delivery Points in Zone 1a would pay Compression Capacity Charges and Compressor Fuel Charges associated with Compressor Stations 1 and 2 regardless of whether or not these compressor stations lie between the contracted gas Receipt Points and Delivery Points; and

- Users with Delivery Points in Zone 10 but upstream of Compressor Station 10 would pay Compression Capacity Charges and Compressor Fuel Charges associated with Compressor Station 10.

398. I consider that compressor fuel costs and some other compression-related costs (particularly compressor maintenance costs) can be regarded as avoidable costs in the provision of services to a particular User. As such, determining compressor-related charges on a zonal basis rather than on the basis of the passing of gas through compressors can be considered contrary to a criterion of efficiency in the tariff structure. Compressor fuel costs and some other compression-related costs (particularly compressor maintenance costs) may be regarded as avoidable costs in the provision of services to a particular User. An efficient structure of the Reference

[117] Access Arrangement Information, section 2.2.

Tariff would therefore be more readily achieved with compression charges being determined on a pass through basis, as proposed by Epic Energy in the Access Arrangement Information, rather than on a zone basis, as used by Epic Energy in its specification of tariffs.

399. Epic Energy has proposed that the Pipeline Capacity Charge recover fixed costs associated with actual pipeline assets, comprising maintenance costs and capital costs. As the Pipeline Capacity Charge recovers these costs on a quasi-distance basis (through pipeline zones) and recovery of costs is in proportion to a User's contracted capacity on the pipeline, it is unlikely that the charges would exceed the corresponding costs of a stand-alone service for any User. There is therefore no basis upon which to object to the zonal structure of the Pipeline Capacity Charge on efficiency grounds.

400. In regard to considerations of equity, distanced-based charges as well as postage-stamp charges are both common forms of pricing in the gas transmission industry (including to date with the DBNGP), and both meet (different) criteria of equity in recovery of fixed costs. As a combination of the two generic types of charge structure, the zonal Pipeline Capacity Charge is consistent with a broad equity consideration of charges determined on the basis of a User's level of use of assets. That is, under the zonal tariff structure Users with similar (but not necessarily equal) haulage distances would in many cases be paying the same charge. I am therefore of the view that the zonal structure of the Pipeline Capacity Charge is equitable.

401. Several submissions made in regard to the zonal structure of the Reference Tariff suggested that the proposed boundaries of pipeline zones result in an inequitable tariff. Concerns were expressed in regard to boundaries of Zones 9 and 10 of the pipeline in relation to Delivery Points, and boundaries of Zone 1 of the pipeline in relation to Receipt Points.

402. Under the tariff structure of the *Dampier to Bunbury Pipeline Regulations 1998* all Users with Delivery Points in what is proposed to be Zones 9 and 10 faced a single "postage stamp" tariff. It was either stated or implied in the submissions made to me that this tariff structure should be maintained, with the part of the DBNGP downstream of Compressor Station 9 being treated as a single pipeline zone. One submission also suggested that the higher tariff for Zone 10 results in subsidisation of Users in Zones 1 to 9 by Users in Zone 10.

403. In considering the issue of pipeline zones downstream of Compressor Station 9, I recognise that Epic Energy's proposal for dividing the section of the DBNGP south of Compressor Station 9 into two zones for the purposes of the Reference Tariff has the effect of introducing a quasi distance-based tariff for this part of the pipeline. Submissions made to me on the proposed Access Arrangement appear to be generally supportive of some form of distance-based tariff, at least for the section of the pipeline upstream of Compressor Station 9, and that this appears to be a commonly accepted criterion of equity in a transmission pipeline tariff. Submissions are somewhat self-contradictory in supporting a distance-based tariff for the pipeline section upstream of Compressor Station 9 while opposing a similar tariff structure in the downstream section of the pipeline. I take the view that a distance-based tariff is broadly supported by Users, at least in principle, and thus I see no reason to reject Epic

Energy's proposal for creation of two pipeline zones in the section of the DBNGP downstream of Compressor Station 9 for the Firm Service.

404. In regard to whether a higher charge for Users in Zone 10 than in Zone 9 results in a cross subsidy from Zone-10 Users to Zone-9 Users, several tests may be used to indicate the presence or absence of cross subsidies. A customer may be cross subsidising others if the price paid by that customer exceeds the stand-alone cost of a service to that customer. Alternatively, a customer may be cross subsidised if the price being paid is less than the incremental cost of providing the service to that customer. In practice, there can be a wide band between stand-alone and incremental costs of service provision, and hence there may be a wide range of "cross-subsidy-free" prices. It is likely that regardless of the difference in tariffs between Zones 9 and 10 that each User would be paying more than the avoidable cost of the service they are receiving and less than the stand alone cost, and hence it cannot be held that there is a cross subsidy between Users.

405. Submissions made to me also address the proposed locations of zone boundaries, particularly the boundary between Zones 9 and 10, and in particular inconsistencies in specifying zone boundaries in relation to compressor stations. Most of the boundaries are one kilometre downstream of the relevant compressor station, except for the Zone 10 boundary that is upstream of Compressor Station 10. It is suggested in submissions that the boundary between Zones 9 and 10 has been located to capture the majority of the Perth metropolitan gas demand and Kwinana demand within Zone 10, and hence charge a higher tariff for this gas transmission.

406. As I have indicated above, the zonal tariff structure should be applied only in determination and imposition of the Pipeline Capacity Charge and not to compression charges (paragraph 398). The proposed location of the boundary between Zones 9 and 10 would result in Users with Delivery Points in Kwinana paying a charge that is based in part on recovery of costs associated with the pipeline assets in Zone 10. However, if compression charges are determined strictly on the basis of whether or not a User's gas passes through the relevant compressor stations, it does not result in these Users paying charges related to Compressor Station 10 unless the Delivery Points are located downstream of this compressor station.

407. Submissions also indicated opposition to the definition of Zone 1 that has all gas Receipt Points for the pipeline located in this zone, and results in transmission charges being the same for any given Delivery Point regardless of the location of the Receipt Point. The view was expressed in submissions that this has the effect of negating cost advantages in gas transmission for gas producers closer to the South-West market.

408. North West Shelf Gas also commented on the proposal for all gas Receipt Points to be considered as being in a single zone of the pipeline, noting that this would cause the North West Shelf Joint Venturers to lose their present geographical advantage (under the part-haul tariff arrangements of the *Dampier to Bunbury Pipeline Regulations 1998*) to supply gas to Hamersley Iron and Robe River Mining. North West Shelf Gas did, however, indicate support for the definition of Zone 1 on the basis that it will help to provide "level playing field" conditions and promote effective competition between gas producers. North West Shelf Gas also supported the principle of back haul to Delivery Points in Zone 1 being the same cost as forward haul to Delivery Points in Zone 1. If back haul were to be offered at a lower cost than forward haul, it

would destroy the 'level playing field' in favour of gas producers further south on the DBNGP. Such a situation would fail to recognise the role of the North West Shelf Joint Venturers in developing the gas reserves of the North West Shelf to underpin the construction of the DBNGP in the first place. North West Shelf Gas did, however, indicate concern over the ability of other gas producers to negotiate with Epic Energy to secure lower back haul tariffs (than the proposed Access Arrangement Reference Tariff) to customers in Zone 1a that are geographically close to the plant of the North West Shelf Joint Venturers.

409. Notwithstanding the indication of general support for the zonal structure and inclusion of all current Receipt Points for gas in Zone 1, North West Shelf Gas suggested that the zone boundaries be altered to either extend the downstream boundary of Sub-Zone 1a to the inlet point of Compressor Station 1, or to split the current Sub-Zone 1a into two sub-zones. The stated reason for such changes was to allow gas to be transported to future Delivery Points in that part of the DBNGP that is currently in Sub-Zone 1b, but upstream of Compressor Station 1, at tariffs less than those that would apply to Sub-Zone 1b.

410. The submissions on the proposed inclusion of all current Receipt Points in a single pipeline zone reflect the economic positions of the parties making the submissions, and in particular the advantages or disadvantages that would accrue to the particular parties from having tariffs vary according to the location of gas receipt into the DBNGP. North West Shelf Gas, which utilises a Receipt Point at the upstream end of the DBNGP, supported the proposal. Apache Energy, which utilises a Receipt Point some 137 km downstream of the North West Shelf Gas Receipt Point, opposed the proposal.

411. I noted above that the proposed zonal structure of the pipeline is, or at least should be, important only in relation to the determination of the Pipeline Capacity Charge and not to compression charges.

412. The Pipeline Capacity Charge is designed to recover the fixed costs of providing and maintaining the pipeline assets of Zone 1. These costs are incurred jointly in the provision of services to all Users regardless of the location of Receipt Points. Consequently, an economically efficient charge for recovery of these costs would be one where Users pay an amount less than the costs to the User of constructing assets for a stand-alone service. Epic Energy's proposed "uniform rate" Pipeline Capacity Charge for Zone 1 would appear to meet this efficiency criterion.

413. In regard to matters of equity in Epic Energy's proposed definition of Zone 1 and the Pipeline Capacity Charge, I again note that the issue is one of recovery of joint costs of service provision. The views expressed in the submission from North West Shelf Gas are of some relevance here in that all current gas producers are utilising existing pipeline assets representing a "sunk" capital investment. A range of criteria of equity could be applied in assessment of a proposed tariff structure, including that the costs should be recovered uniformly, or that costs should be recovered on a throughput basis, or that costs should be recovered on a distance basis. No single criterion necessarily has any superiority over another, except in so far as it may be generally acceptable as reasonable in the specific context in which it is being applied. I am of the view that the proposed definition of Zone 1 and uniform rate of the Pipeline Capacity Charge is one criterion, possibly amongst many, that would be considered

generally acceptable and on this basis I do not consider there to be any reason to reject Epic Energy's treatment of Zone 1 for reasons of it being inequitable.

414. As a final matter in relation to pipeline zones, a submission to me drew attention to a possible discrepancy in the description of Delivery Points in different pipeline zones, noting that the Eradu Road Delivery Point (to send gas into the Mid-West Pipeline) is within one kilometre downstream of the CS7 isolation valve (MLV 90) and therefore should be within Zone 6 and not Zone 7 as stated in the proposed Access Arrangement. After having this matter drawn to its attention by the submission, Epic Energy has confirmed that the Eradu Road Delivery Point is indeed in Zone 6 of the pipeline.

415. A matter potentially affecting the determination of the Reference Tariff is the forecast of throughput for the Access Arrangement Period. Under Epic Energy's proposed Reference Tariff Policy, the throughput forecast would not affect the Reference Tariff for the Access Arrangement Period. It would, however, affect the forecast revenue for the Access Arrangement Period and the amount of deferred depreciation and, hence, potentially the magnitude of Reference Tariffs in the future.

416. Several submissions made to me questioned Epic Energy's demand forecasts for the Access Arrangement Period provided in section 6.3 of the Access Arrangement Information. The forecasts provide for overall increases in contracted capacity and throughput of 13.2 TJ/day (2.2 percent) and 25.3 TJ/day (4.8 percent), respectively, over the Access Arrangement Period, with all of the forecast increase in throughput occurring in Zones 9 and 10 of the pipeline, and decreases in contracted capacity and/or throughput occurring in Zone 1a (Hamersley Iron and Robe River Mining Delivery Points) and Zones 6 and 7 (Eradu Road and Geraldton to Eneabba Delivery Points).

417. In my Draft Decision, I examined information from a range of sources for the purpose of validating Epic Energy's demand forecasts:

- forecasts by the Office of Energy of demand for natural gas over the period 2000 to 2009;[118]
- forecasts of gas throughput for the AlintaGas Mid-West and South-West Gas Distribution Systems;[119] and
- historical contracted capacity and gas throughput for the DBNGP for the years 1998, 1999 and 2000.

418. Overall, I took the view that Epic Energy's throughput forecast was reasonable if major industrial projects such as the An Feng Kingstream and Mt Gibson projects were not taken into consideration, which in hindsight has proved prudent.

[118] Office of Energy Western Australia, 2001. *Energy 2000 Western Australia*.

[119] AlintaGas, 2000. *AlintaGas's Access Arrangement Information for the Mid-West and South-West Gas Distribution Systems*.

419. Turning to the magnitude of the Reference Tariff, several submissions made to me included comment on the magnitude of the proposed Reference Tariff, independently of comments made in regard to Epic Energy's proposed methodology of cost allocation and tariff structure. The comments in relation to the Reference Tariff generally related to comparisons of the proposed Reference Tariff with either tariffs established by the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998*, tariffs proposed by Epic Energy in the DBNGP Asset Sale Agreement, and/or levels of tariffs indicated in statements made by the Minister for Energy. Submissions made particular comment on the level of the proposed tariffs for Delivery Points located in the Pilbara Region (pipeline Zone 1a), for Carnarvon (Zone 4a) and for the Perth metropolitan and South West regions (Zones 9 and 10).

420. In regard to a general matter on the level of the Reference Tariff, submissions from existing Users indicated that the proposed Reference Tariffs are substantially greater than the current tariff for parties with contracts entered into under the Gas Transmission Regulations 1994. Submissions indicated that the Reference Tariff for Zones 9 and 10 would exceed the current tariff as a result of the $1.08/GJ tariff proposed for Zone 10, Delivery Point Charges which is over and above the $1.00 or $1.08 headline tariffs, and the different tariff structure for the Firm Service tariff with a higher proportion of capacity-related charges. The submissions also pointed out that such a tariff is contrary to Users' expectations from the Sale Process which was for a $1.00 tariff for both zones 9 and 10 with a tariff structure the same as the T1 Service under the *Dampier to Bunbury Pipeline Regulations 1998*.

421. Submissions also noted very substantial increases in tariffs that would occur for Users with Delivery Points in the Pilbara Region and at Carnarvon, noting that the tariff increases would have substantial effects on competition, including competition between gas and other fuels for electricity generation, and competition between gas producers for potential gas delivery via the DBNGP into the Goldfields Gas Pipeline. One submission also noted that tariffs for gas delivery at Mondarra would also be sufficiently high as to discourage competition between the DBNGP and the Parmelia Pipeline for delivery of gas from Mondarra.

422. I address first the issue of the magnitude of the proposed Reference Tariff in Zones 9 and 10 of the pipeline. The charges proposed by Epic Energy that make up the Reference Tariff for the Firm Service correspond to "100 percent load factor" tariffs for these zones of $1.00/GJ and $1.08/GJ, plus the amount of the Delivery Point Charge. My own analysis of these charges leads me to concur with parties making submissions that these charges would give rise to prices for gas transmission significantly greater than would arise from the 100 percent load factor tariff of $1.00/GJ currently applying under the *Dampier to Bunbury Pipeline Regulations 1998*.

423. Epic Energy has indicated that justification for its proposed Reference Tariff arises from the process of the sale of the DBNGP and the foreshadowing of these tariffs by section 39 of the sale agreement. While I am of the view that the Sale Process could have led a reasonable person bidding for the DBNGP to give weight to a future tariff path arising from the Sale Process, I do not consider that it would have been reasonable to consider such a prospect other than as a tariff in the nature of full-haul transmission tariff of $1.00 per GJ as at 1 January 2000, with this tariff being consistent with the tariff for the T1 Service, in relation to matters such as tariff

structure. I therefore do not consider that Epic Energy's proposed tariffs are justified as an outcome of the Sale Process.

424. In regard to the level of the Proposed Reference Tariffs in other zones of the pipeline, I note that in my Draft Decision I foreshadowed a significant decrease in the Reference Tariff for gas transmission to Zones 9 and 10 relative to that proposed by Epic Energy, and relative to the current tariff under the Dampier to Bunbury Pipeline Regulations. I indicated in those circumstances that it would be inappropriate for Users with Delivery Points in other Zones to experience substantial increases in tariffs. I still maintain the general view that while some tariff change may appropriately result from different cost allocations, that a substantial tariff increase within a short period for some Users, while tariffs for the pipeline as a whole generally decrease or are held approximately constant, is unreasonably contrary to the interests of Users.

425. Several submissions made comment on the proposed tariff structure, both in terms of the nature of proposed charges making up the Reference Tariff and the proportions of the charges that comprise fixed (capacity-related) charges relative to variable (throughput-related) charges. It was generally noted in submissions that an effect of the high proportion of fixed charges would be to shift the commercial risk of lower demands for transmission services from Epic Energy to Users. AlintaGas indicated that for a given value of a 100 percent load factor tariff, a higher fixed charge component of the tariff results in a higher effective tariff once load factors of less than 100 percent are taken into account, which particularly affects gas transmission costs for the supply of gas to residential and small-business end users.

426. Epic Energy has limited throughput charges to the recovery of compressor fuel costs through the Compressor Fuel Charge. Under Epic Energy's proposed tariff structure, this causes throughput charges to comprise approximately five percent of the 100 percent load factor tariff for Delivery Points downstream of Zone 1. Epic Energy's justification for this distribution of cost recovery to the throughput charge is that compressor fuel costs are the only costs incurred in the operation of the DBNGP that vary with throughput.

427. An efficient tariff structure would in general be one where for the last unit of a service consumed, the User would pay a tariff equal to the incremental cost to the Service Provider of providing that last unit. This is consistent with a tariff structure based on recovery of fixed costs by up-front charges (e.g. capacity charges) and recovery of variable costs by a charge per unit of the service consumed (e.g. throughput charges). The tariff structure proposed by Epic Energy would meet this criterion of efficiency if, as argued by Epic Energy, the only variable cost is the cost of compressor fuel.

428. Definitions of variable costs may differ between industry participants, ranging from all operations and maintenance costs to strictly incremental costs that arise as throughput is increased. I am of the view that in relation to an efficient tariff structure, the appropriate definition of variable costs would be the latter. This would include compressor fuel costs, as proposed by Epic Energy, and possibly also some compressor maintenance costs. I accept, however, the position put by Epic Energy that, within the range of short-term fluctuations in throughput, compression maintenance costs might be regarded as fixed costs. In view of this, I consider it is

not inconsistent with criteria of economic efficiency that the only throughput charge is a charge for recovery of compressor fuel costs.

429. I have noted the concerns expressed in submissions as to the implications of the fixed and throughput components of the tariff for the relative risks borne by Users and Epic Energy, and equity in both the distribution of risk and the actual costs of gas transmission to Users. Where Users transport gas at a load factor of less than 100 percent, a relatively small throughput component of the proposed Reference Tariff would have the result of producing a lower "100 percent load factor" tariff if the target Total Revenue remains the same. In comparison with a tariff that has a higher throughput component, this would result in Users with relatively low load factors paying more for gas transmission and Users with relatively high load factors paying less. This was noted in a submission from AlintaGas that indicated the effect of increasing transmission costs for gas used to supply residential and small-business customers for whom load factors are typically low. Further, the financial risk of reductions in gas throughput during the term of an Access Contract are borne to a greater extent by the User than by Epic Energy, as the User pays a higher proportion of the tariff as fixed or capacity charges. These consequences of the tariff structure proposed by Epic Energy have implications in consideration of the proposed tariff against criteria of equity.

430. Turning to matters related to individual charges of the Reference Tariff, a submission made to me raises concern that the nature of the Compressor Fuel Charge, with recovery of forecast costs of gas use rather than the actual cost, reduces incentives for Epic Energy to efficiently operate the pipeline. I have considered this matter and come to a contrary view. An incentive for efficient operation of the pipeline is created by Epic Energy being able to capture the benefits of efficiency gains over a period before the Access Arrangement is reviewed and cost savings passed on to Users through lower tariffs in the subsequent Access Arrangement Period. Such an incentive is consistent with the principles of the Code.

431. Further submissions commented on the compression charges in relation to Compressor Station 10, suggesting that the necessity of Compressor Station 10 arises at least in part from the reduction in gas pressure occurring as gas passes through the Wesfarmers LPG plant. In view of this, it was questioned whether Users in Zone 10 should be paying for compression, the need for which arises from an activity in Zone 9, or whether Wesfarmers LPG should be meeting part of these compression costs. I note that the contractual arrangements between Epic Energy and Wesfarmers LPG require gas to be returned from the LPG plant to the pipeline at a minimum pressure not less than 100 kPa less than the delivery pressure to the LPG plant, up to a maximum pressure of 4.75 MPa. Further, the requirement for Compressor Station 10 arises from increases in demand for services downstream of the Wesfarmers LPG plant. In view of both of these factors, I consider it reasonable that the costs associated with Compressor Station 10 are recovered from Users with Delivery Points downstream of this compressor station.

432. Several submissions addressed the proposed Gas Receipt Charge. Epic Energy has determined the Gas Receipt Charge to recover costs attributed to:

- return on assets other than pipeline, compression and metering assets;

- depreciation of assets other than pipeline, compression and metering assets; and
- Non Capital Costs other than costs attributed to operation and maintenance of pipeline, compressor stations, and metering assets.

433. The proposed Gas Receipt Charge is a fixed, periodic charge, independent of contracted capacity, throughput or distance of gas transmission.

434. Submissions queried whether a constant charge across all Users is equitable, and queried whether the proposed charge over-recovers the overhead Non Capital Costs that it is purported to recover, and whether these costs are indeed fixed or are variable.

435. Epic Energy has provided information to me to indicate that the Non Capital Costs recovered by the Gas Receipt Charge included costs associated with finance and administration, human resources, legal services, information technology, marketing and business development, public relations, corporate overheads and "special projects". I am satisfied from the information provided by Epic Energy that the costs recovered by the Gas Receipt Charge do not include costs of compressor fuel gas, although I note that the costs recovered by the charge do include costs for other gas used in operations such as gas lost in blow-downs and purges.

436. I am also satisfied that the costs recovered by the Gas Receipt Charge are, for all practical purposes, fixed costs with respect to pipeline throughput, at least within the range of throughput being considered for the Access Arrangement Period. The allocation of costs between Users is largely arbitrary, although the allocation may be assessed against broad considerations of equity.

437. Epic Energy has proposed that the Gas Receipt Charge be levied as a rate per unit of contracted capacity (MDQ) without regard to a User's distance of gas transmission. Given that most of the costs recovered by the Gas Receipt Charge are not related to specific assets for the DBNGP nor are incurred directly in operation of the DBNGP, I consider that this basis for the Gas Receipt Charge is a compromise between a fixed charge per user and a charge levied on a basis of distance and quantity of gas delivery. In view of this, I do not consider there is reason to reject, in principle, Epic Energy's proposed basis for levying the Gas Receipt Charge.

438. Notwithstanding this, the Gas Receipt Charge, as currently determined, is the principle factor contributing to the proposed Reference Tariff for gas transmission to Delivery Points in the Pilbara region being greater than the tariff that would currently apply under the *Dampier to Bunbury Pipeline Regulations 1998*, a matter which I have indicated above to not be consistent with the reasonable interests of affected Users.

439. The remaining component of the Reference Tariff attracting comment in submissions was the Delivery Point Charge. Epic Energy has proposed that the Delivery Point Charge recover costs attributed to:

- return on Delivery Point assets; and
- depreciation of Delivery Point assets.

440. Several submissions made to me addressed the Delivery Point Charge, querying the level and justification for the charge, and the manner of application of the charge. In considering Epic Energy's proposed Delivery Point Charge and the public submissions made on this matter, I have given consideration to the following matters:

- The nature of the capital costs that Epic Energy proposes to recover through the Delivery Point Charge and whether it is reasonable for these costs to be recovered in the manner proposed.

- The provisions for apportionment of the Delivery Point Charge where a Delivery Point is used by multiple Users.

441. While Delivery Point facilities are owned by Epic Energy, in many cases these Delivery Points have been paid for, or are being paid for, by Users through either up-front or annuity payments. The investment in Delivery Point facilities has, therefore, in many cases been financed by Users rather than the owner of the DBNGP, in a manner similar to that contemplated by sections 8.23 and 8.24 of the Code in respect of capital contributions.

442. The existing Users that have met, or are meeting, the costs of the Delivery Point facilities would continue to receive services under the terms and conditions of existing contracts, meaning that they would not, at least in the first instance, be paying additional capital costs of these facilities through the proposed Delivery Point Charge. However, new and existing Users may pay the Delivery Point Charge in respect of new or additional contracted capacity. This could conceivably result in Epic Energy earning revenue from facilities for which the cost was not met by either Epic Energy or previous owners of the DBNGP.

443. Circumstances of capital contributions from Users and interactions with Reference Tariffs and charges are dealt with in sections 6.20, 6.23 and 8.23 to 8.26 of the Code. While these provisions of the Code may not necessarily be relevant or binding in respect of all situations for which Users paid for facilities prior to the commencement of the Code, the provisions nevertheless give some guidance as to how such circumstances may be dealt with for the purposes of the proposed Access Arrangement and Reference Tariff. The general principles of the Code in this respect are as follows:

- Where a User makes capital contributions in respect of New Facilities, the terms of access for that User should reflect the value to the Service Provider of the contribution that the User made. That is, the tariff to the User should incorporate a rebate that, in effect, returns to the User the "return on assets" and "depreciation" associated with the User's capital contribution, as if the User were just another provider of finance to the project.

- New Users of facilities that have been financed by other Users should pay tariffs and charges for services as if the Service Provider had financed those facilities. This principle ensures that subsequent Users, or Users generally, are not able to free-ride on the first User's capital contribution. However, the component of tariffs or charges paid by new Users that reflects the return on capital or return of capital in relation to facilities that have been financed by other Users should be returned to those Users that made the capital contributions, or to Users generally, rather than being retained by the Service Provider.

444. I see no in-principle difficulty in respect of the provisions of the Code for the Reference Tariff to include a charge specifically for the recovery of capital costs of Delivery Point facilities. However, I consider that the current proposal may allow Epic Energy to retain revenue from these charges where Users meet the costs of the facilities. This outcome would be inconsistent with the principles of the Code relating to Capital Contributions and Surcharges, and inconsistent with a reasonable balance between the interests of the Service Provider and Users.

445. A further concern that I have in regard to the Delivery Point Charge and the recovery of capital costs associated with Delivery Point facilities is the valuation of these assets for the purposes of determining the Reference Tariff. On the basis of information provided to me by Epic Energy, it appears that values ascribed to Delivery Point assets are largely arbitrary with little consistency in values ascribed to otherwise similar facilities. This may complicate the determination of mechanisms for the return of revenue to Users that financed these facilities, in general accordance with the provisions of the Code relating to Capital Contributions and Surcharges. Given the situation with ownership and payment for Delivery Point facilities, I would consider it appropriate that these facilities be valued on an historical cost basis or DORC basis, and if there is any upward revaluation of Delivery Point facilities that Users should capture the benefits of the revaluation in respect of assets that were financed by Users.

446. As a final matter in relation to the Delivery Point Charges, I note the concern expressed in submissions as to the difficulty in determining Delivery Point Charges where Delivery Points are shared by Users. I am of the view that the proposed Access Arrangement provides insufficient information in this regard.

447. Moving to the matter of prudent discounts to the Reference Tariff, AlintaGas has submitted to me that in approving a Reference Tariff, I should permit Epic Energy to make provision for the contractual discount that it provides for the delivery of gas to the Wesfarmers LPG plant, in accordance with provisions of section 8.43 of the National Access Code relating to prudent discounts. According to AlintaGas, the Wesfarmers LPG plant extracts propane and butane from the stream of natural gas flowing in the DBNGP at Kwinana Junction. AlintaGas contends that a discount is justified by the higher energy content of propane and butane than an equivalent volume of natural gas, and also that precedent for a discount exists through incorporation of provisions for a discount in the *Gas Transmission Regulations 1994*. AlintaGas also states that, Epic Energy indicated in Schedule 39 of the Asset Sale Agreement that the discount would be incorporated in the reference tariff, and it was a grandfathered obligation at the time Epic Energy purchased the DBNGP.

448. A further submission from a gas producer raised a similar issue, commenting that the relationship between tariff and gas quality has not been addressed, and contending that as AlintaGas has access to a tariff reduction of 50 percent for transport of producer LPG to Wesfarmers, other Users with rich gas should expect to pay a lower tariff than those with lean gas.

449. The 50 percent discount provided to AlintaGas for gas transported and sold by AlintaGas to Wesfarmers LPG Pty Ltd arose from section 146 of the *Gas Transmission Regulations 1994*:

> 146. (1) The [Gas Corporation] is to grant to the corporation's other business a discount of 50% on each of the capacity reservation charge and the commodity charge payable by the corporation's other business in respect of the actual quantity of gas sold by it to Wesfarmers LPG Pty Ltd for use (whether for extraction, as fuel or otherwise) in the WLPG plant.
>
> (2) For the purposes of determining or redetermining a price in accordance with this Part, the effect of the discount under this regulation on the corporation's revenue is to be determined using the corporation's other business' best estimate as a reasonable and prudent person of the WLPG plant's gas usage in the year following determination or redetermination.

450. The provision for the discount to AlintaGas was not carried over into the *Dampier to Bunbury Pipeline Regulations 1998*, although it was indicated in Schedule 39 to the DBNGP Asset Sale Agreement that the 50 percent discount for gas delivered to Wesfarmers LPG would continue to apply after sale of the pipeline. I also note that the discount provided to AlintaGas in respect of gas delivered to Wesfarmers LPG may be a condition of a haulage contract between Epic Energy and AlintaGas.

451. Epic Energy has not taken into account in determination of the Reference Tariff any contractual obligation to provide a discount tariff in respect of gas deliveries to Wesfarmers LPG. Should Epic Energy have proposed that the discount be incorporated into determination of the Reference Tariff, I would have assessed whether the discount meets the criteria of a prudent discount under section 8.43 of the Code. However, in the absence of a proposal from Epic Energy, this assessment has not been undertaken.

452. As a final matter in relation to tariffs, several submissions made to me addressed Epic Energy’s proposal for some Non-Reference Services to be Rebatable Services. The relevant Non-Reference Services are indicated in section 9.1 of the proposed Access Arrangement to be the Seasonal Service, the Park and Loan Service, the Secondary Market Service and any other service nominated by Epic Energy. Additionally, Epic Energy has also proposed that revenue (less the Compressor Fuel Charge) obtained by Epic Energy from Overrun charges under sub-clause 5.2 of the Access Contract Terms and Conditions is Rebatable Revenue.

453. The mechanism for determining an amount of Rebatable Revenue and the proposed distribution of rebates were set out by Epic Energy in section 9.2 of the proposed Access Arrangement and, in a modified form, in a later submission to the Regulator. The provisions of the proposed Access Arrangement relating to Rebatable Revenue were described in paragraphs 390 and 391 of this Final Decision.

454. Submissions made to me raised a number of concerns in respect of provision under the proposed Access Arrangement for Rebatable Services, including the following.

- For the purposes of determining the Reference Tariff, revenue was assumed to be obtained only from the Firm Service, with no portion of Total Revenue/costs assumed to be recovered from the various Non-Reference Services specified in the Services Policy of the proposed Access Arrangement. While some of the Non-Reference Services were designated to be Rebatable Services, others (such as the

Peaking Service) are not. By not seeking to recover a portion of Total Revenue from these services, nor treating them as Rebatable Services, the opportunity arises for Epic Energy to recover revenue in excess of the Total Revenue.

- Whether provisions for rebate of revenue strike an appropriate balance between rebates and the retention of revenue by Epic Energy.

455. In regard to the prospect of Epic Energy earning additional revenue from sale of Non-Reference Services that are not Rebatable Services, I gave consideration to the mechanisms by which prices for each of the proposed Non-Reference Services are to be, or are likely to be, determined. For Non-Reference Services, prices would either be set by Epic Energy or determined by negotiation between Epic Energy and Users. In the event that terms and conditions for provision of the service, including the price for the service, are not agreed by negotiation, Users have the option of recourse to the arbitration provisions of section 6 of the Code. A factor that the Arbitrator must take into account in determining a price is the cost to the Service Provider of providing access. The prospect or reality of arbitration may therefore serve to limit the setting of prices for Non-Reference Services at levels above the cost of providing the service. I do not consider that it is necessary for the Access Arrangement to make provision for all Non-Reference Services to constitute Rebatable Services.

456. In considering an appropriate proportion of the Rebatable Revenue (or Distributable Revenue in the terminology used by Epic Energy), I had regard to provisions of the Code in respect of Rebatable Services.

457. Section 8.40 of the Code states that the structure of a rebate mechanism should be determined having regard to, *inter alia*, the objective of providing the Service Provider with an incentive to promote the efficient use of pipeline capacity, including through the sale of Rebatable Services. I am of the view that provision of such an incentive would require that the Service Provider be able to retain a portion of revenue from the sale of Rebatable Services that is in excess of the avoidable cost of providing that service. Epic Energy has proposed to retain 15 percent of Distributable Revenue, plus an additional 40 percent that, for regulatory purposes, is credited to the proposed deferred recovery account. Part of the revenue retained by Epic Energy would need to be used to meet costs of compressor fuel that, for all practical purposes, would constitute the avoidable cost of providing the relevant services (noting that Rebatable Revenue from Overrun charges already excludes the compressor fuel charge). I consider that retention by Epic Energy of 15 percent of Distributable Revenue may provide sufficient incentive to offer the Non-Reference Services. In regard to the 40 percent of revenue that would be credited to the deferred recovery account, I note my previous comment in this Final Decision that the Initial Capital Base proposed by Epic Energy is at an inappropriately high value. With a lower Capital Base there may be no requirement for a deferred recovery account. In such a situation I consider it necessary for Epic Energy to re-consider the apportioning of revenue from Rebatable Services in accordance with its incremental costs of providing the relevant services and an incentive to provide these services.

458. One submission made to me commented that the absence of provision for persons with prior contracts to share in revenue rebates is inequitable and inconsistent with the objectives for a Rebatable Service. This submission indicated that the objective for Rebatable Revenue should be that the rebates be used to compensate either holders of

prior contracts or Epic Energy for the over-recovery or under-recovery of revenue from prior contracts relative to the revenue that would have been obtained if the prior contracts were contracts for the Reference Service. The submission also indicated that insufficient information was provided for Shippers to be able to assess the likelihood of a distribution at any time.

459. I am of the view that to require that Epic Energy make provision for rebates to holders of prior contracts would, in effect, amount to a variation of the terms and conditions of those prior contracts. This would be contrary to the legitimate business interests of Epic Energy, and contrary to the requirements of section 2.25 of the Code that states that the Regulator must not approve an Access Arrangement any provision of which would, if applied, deprive any person of a contractual right in existence prior to the date the proposed Access Arrangement was submitted. I therefore will not require the proposed Access Arrangement to be amended to make provision for rebates of Distributable Revenue to holders of prior contracts.

460. In regard to the submission that insufficient information is provided for Users to be able to assess the likelihood of a distribution at any time, I note that no forecasts have been made of sales of the Rebatable Services or the prices charged for these services, and hence there is no information to make predictions as to the amount of rebate payments. I do not, however, regard the absence of forecasts of rebate payments as inappropriate for Rebatable Services, one advantage of which should be to obviate the need to make forecasts for minor services of the regulated pipeline.

461. A further submission comments that Epic Energy has not provided sufficient information to enable Users to determine the adequacy of the proposed method of rebate noting that there is a lack of definition of variables in the formulae specified for determination of rebates, and a lack of justification for Epic Energy's proposal to include in the "Threshold Revenue" a value of $0.40 multiplied by the actual volume (in gigajoules) of gas delivered in the year in excess of the forecast volume for that year.

462. I concur with the view that the provisions of the proposed Access Arrangement relating to Rebatable Revenue are difficult to understand. To a large extent, however, Epic Energy has addressed this difficulty in the modified provisions submitted to the Regulator and set out paragraphs 390 and 391 of this Final Decision. In this additional information, Epic Energy has indicated that the inclusion in the Threshold Revenue of a value of $0.40 multiplied by the actual volume of gas delivered in the year in excess of the forecast volume for that year is to accommodate the associated increased operating costs and the consequential impact on its revenue due to the out-workings of the contract between Epic Energy and Alcoa. I consider that as a grandfathered provision of a contract inherited by Epic Energy upon purchase of the DBNGP, the associated cost is a legitimate cost in the sale of Non-Reference Services. To not recognise this cost in the determination of rebates would reduce the incentive for Epic Energy to sell Non-Reference Services, which is contrary to the efficient utilisation of pipeline capacity and growth in the market for pipeline services.

463. In addition to the matters discussed in submissions in relation to the Rebatable Services, I have some concern over the calculation of Threshold Revenue. Epic Energy has proposed that the Threshold Revenue be calculated as the amount by which actual revenue from the sale of the Firm Service falls short of that component

of Total Revenue attributable to the provision of the Firm Service, plus the cost of providing those services from which Rebatable Revenue was obtained. Epic Energy may provide services of a similar nature to the Firm Service as a Non-Reference Service, differing from the Firm Service only in respect of some terms and conditions without the general nature of the service being materially different. By not including revenue from such Non-Reference Services in the calculation of Threshold Revenue, the proposed mechanism for Rebatable Revenue gives rise to an incentive for Epic Energy to provide transmission services as Non-Reference Services, even though services may not be materially different to the Reference Service, and thereby reduce the liability for payment of rebates.

464. I am therefore of the view that the proposed method of calculation of Threshold Revenue is contrary to the objective for an incentive mechanism as set out in section 8.46(a) of the Code: an incentive mechanism should be designed with a view to providing the Service Provider with an incentive to increase the volume of sales of all services, but to avoid providing an artificial incentive to favour the sale of one service over another. This problem could be overcome by revising the method of calculation of Threshold Revenue to be the amount by which actual revenue from the sale of the Firm Service, and other services in the nature of the Firm Service, falls short of that component of Total Revenue attributable to the provision of Firm Service, plus the cost of providing those services from which Rebatable Revenue was obtained.

465. Under clause 9.1 of the proposed Access Arrangement, Epic Energy has proposed that revenue obtained by Epic Energy from the Overrun Charge (less relevant compression charges) will comprise Rebatable Revenue for the purposes of section 9 of the proposed Access Arrangement. There is no proposal for revenue from any other penalty charges to be treated as Rebatable Revenue.

466. Submissions made to me have indicated that anticipated revenue from penalty charges should be taken into account in determination of the Reference Tariff through subtraction from the Total Revenue requirement for the pipeline.

467. Epic Energy responded to these submissions by indicating that in order to remove the perception that surcharges are for the purpose of raising revenue, the Regulator may consider requiring any revenue received from the imposition of such surcharges to be treated as Rebatable Revenue in accordance with provisions of section 9 of the proposed Access Arrangement, but with some mechanism for ensuring that Rebatable Revenue resulting from surcharges is not distributed back to the User paying the surcharge.[120]

468. I have noted the actual or proposed practice of several other Australian transmission pipelines is for revenues gained by imbalance and/or Overrun penalties to be rebatable.[121] I consider that this is a reasonable practice where the forecast revenue from the penalties is not considered in the determination of Reference Tariffs, as is the case under the proposed Access Arrangement.

[120] Epic Energy (WA) Transmission Pty Ltd, 12 May 2000, Submission 7.

[121] East Australian Pipeline Limited, Proposed Access Arrangement for the Moomba to Sydney Pipeline System, 5 May 1999. Epic Energy, Proposed Access Arrangement for the Moomba to Adelaide Pipeline, 1 April 1999. Envestra Limited, Proposed Access Arrangement for the Riverland Pipeline, 11 November 1999.

469. In regard to the treatment of penalty revenues as Rebatable Revenues, unlike the case for a Rebatable Service as defined by the Code, there is no requirement for the rebate mechanisms to allow the Service Provider to retain a sufficient share of the relevant revenues to ensure an incentive for service provision. In view of this, I consider that it would be appropriate that the rebate mechanism established for penalty revenues provide for a rebate of close to 100 percent of penalty revenues. Acknowledging that some costs may be incurred in the imposition of penalties and operation of a rebate mechanism, I consider that a rebate of 95 percent of penalty revenue would be appropriate. The provisions contemplated here for rebate of revenues from penalty charges differ from the provisions of the proposed Access Arrangement in relation to rebate of revenue of Non-Reference Services.

Incentive Mechanisms

470. Section 8.44 of the Code provides for a Reference Tariff Policy to include Incentive Mechanisms:

> 8.44 The Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism (an Incentive Mechanism) that permits the Service Provider to retain all, or a share of, any returns to the Service Provider from the sale of the Reference Service
>
> (a) during an Access Arrangement Period that exceed the level of returns expected for that Access Arrangement Period; or
>
> (b) during a period (commencing at the start of an Access Arrangement and including two or more Access Arrangement Periods) approved by the Relevant Regulator, that exceed the level of returns expected for that period,
>
> particularly where the Relevant Regulator is of the view that the additional returns are attributable (at least in part), to the efforts of the Service Provider. Such additional returns may result, amongst other things, from lower Non Capital Costs or greater sales of Services than forecast.

471. Section 8.45 sets out a number of examples of Incentive Mechanisms:

> 8.45 An Incentive Mechanism may include (but is not limited to) the following:
>
> (a) specifying the Reference Tariff that will apply during each year of the Access Arrangement Period based on forecasts of all relevant variables (and which may assume that the Service Provider can achieve defined efficiency gains) regardless of the realised values for those variables;
>
> (b) specifying a target for revenue from the sale of all Services provided by means of the Covered Pipeline, and specifying that a certain proportion of any revenue received in excess of that target shall be retained by the Service Provider and that the remainder must be used to reduce the Tariffs for all Services provided by means of the Covered Pipeline (or to provide a rebate to Users of the Covered Pipeline); and
>
> (c) a rebate mechanism for Rebatable Services pursuant to section 8.40 that provides for less than a full rebate of revenues from the Rebatable Services to the Users of the Reference Service.

472. Section 8.46 sets out objectives that an Incentive Mechanism should be designed with a view to achieving:

> 8.46 An Incentive Mechanism should be designed with a view to achieving the following objectives:

(a) to provide the Service Provider with an incentive to increase the volume of sales of all Services, but to avoid providing an artificial incentive to favour the sale of one Service over another;

(b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(c) to provide the Service Provider with an incentive to develop new Services in response to the needs of the market for Services;

(d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non Capital Costs, and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non Capital Costs for the purposes of sections 8.16 and 8.37; and

(e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation or volume of sales occur).

473. Section 7.12 of the proposed Access Arrangement describes two incentive mechanisms:

- the adoption of the "price path" approach in the setting of the Reference tariff; and
- the method for distribution of Rebatable Revenue derived from sale of Non-Reference Services.

474. The price path proposed by Epic Energy comprises an escalation of individual charges of the Reference Tariff at a rate of two thirds of the rate of change in the Consumer Price Index.

475. Several submissions made to me commented that a general escalation of the Reference Tariff may be inappropriate where most of the costs underlying the Total Revenue and tariff comprise sunk capital costs, and Epic Energy has used a nominal Rate of Return in calculating the return on capital. A further submission questioned the appropriateness of escalating tariffs in accordance with a general measure of inflation, such as a consumer price index, that does not necessarily reflect changes in costs in the gas transmission industry.

476. In general, it is appropriate to address inflation in the setting and variation of the Reference Tariff so as to ensure that the return on capital and return of capital maintain values in real terms. The way in which this is achieved, and the appropriate use of the inflation escalation, depends on the manner in which the Total Revenue and Reference Tariff are determined. Under Epic Energy's proposed Access Arrangement, the Reference Tariff is determined independently of a Total Revenue requirement. Hence it is arguable that it is appropriate for the tariff to be escalated to reflect both inflation of operating and maintenance costs and to maintain the values of returns on and of capital in real terms. More generally, it is appropriate to annually inflate the tariff charges so that the present value of the actual revenue stream equals the present value of the target revenue stream.

477. For the purposes of maintaining the value of returns on and of capital in real terms, inflation of the Reference Tariff in accordance with an economy-wide measure of inflation is appropriate – with an appropriate measure of inflation being the Eight

Capital City, All-Groups CPI measure as published by the Australian Bureau of Statistics and not the All-Groups Perth measure as proposed by Epic Energy. Compensating a pipeline Service Provider for inflation in Non Capital costs is a different matter, as costs of providing pipeline services would not necessarily change at the same rate as an economy-wide measure of inflation. Notwithstanding this, I consider that inflation of tariffs in accordance with an economy wide measure of inflation is a reasonable methodology to use in the absence of industry-specific inflation measures. In any case, costs would be re-assessed upon review of the Access Arrangement and considered in terms of actual costs at the time of the review and in dollar values at that time. Hence any over recovery of costs in the current Access Arrangement Period that may result from over-compensation for inflation would not be continued into the subsequent Access Arrangement Period.

478. As far as I have been able to ascertain from the information available to me, the choice by Epic Energy to use an escalation factor of two thirds of the rate of change in the CPI reflects the financial modelling of expected regulated tariffs that was undertaken by Epic Energy in developing the value of its final bid for the DBNGP, and presenting expected future tariffs in the form of a price path that it considered would be acceptable to the GPSSC. The adoption of the "two thirds of the change in the CPI" approach rather than a more conventional "CPI–X" approach to specifying a tariff path appears to have been undertaken to limit the prospect of a decline in tariff values in nominal terms that may occur under a CPI–X approach in periods of low inflation.

479. Australian regulatory decisions on gas pipelines and distribution systems have generally not used tariff escalation mechanisms such as CPI–X price caps as incentive mechanisms. While the mechanisms for annual tariff variation have for most Access Arrangements involved CPI-X constraints on annual tariff variations, the value of "X" has typically not reflected productivity improvements beyond those already forecast by the Service Provider and incorporated into cost and demand forecasts. Rather, the X value has been derived as a means of achieving "glide paths" for tariffs so that there is a smooth path of tariff changes over an Access Arrangement Period while preserving the present value of a target revenue stream.

480. The Incentive Mechanism within Epic Energy's proposed price path arises from the prospect of Epic Energy capturing over the remainder of an Access Arrangement Period the benefits of cost reductions or demand growth that were not forecast at the time of approval of the Access Arrangement. The benefits of cost reductions and demand growth may then be passed on to Users in the next Access Arrangement Period.

481. I regard the Incentive Mechanism proposed by Epic Energy to be in accordance with the relevant provisions and intent of the Code.

482. The other Incentive Mechanism included by Epic Energy in the proposed Access Arrangement relates to Rebatable Services and Rebatable Revenue, and in particular provision for Epic Energy to retain a portion of revenue obtained from sales of services other than the Reference Service. I have addressed the provisions of the Access Arrangement relating to Rebatable Services above (paragraph 452 and following). Subject to the matters addressed in my consideration of the relevant provisions of the proposed Access Arrangement, I regard the provisions for Rebatable

Services and Rebatable Revenue to be consistent with the requirements and intent of the Code in relation to Incentive Mechanisms.

Conclusions

483. Having now examined the components of Epic Energy's cost-of-service derivation of proposed Total Revenue and Epic Energy's proposed Reference Tariff for the Firm Service against the relevant principles contained in section 8 of the Code and, where applicable, the factors of section 2.24(a) to (g) of the Code, I set out my conclusions as to whether the proposed Reference Tariff and Reference Tariff Policy comply with the Code. A matter of particular significance to the determination of the Reference Tariff is the value established for the Initial Capital Base. I have given consideration to the Initial Capital Base, in the context of the Reference Tariff, taking account of the factors of section 8.10 of the Code, the objectives of section 8.1, and the factors of section 2.24.

484. From consideration of the factors of section 8.10 of the Code, as set out above in these reasons, I estimate:

- the DAC value of the DBNGP to be $874 million; and
- the DORC value of the DBNGP to be $1,230 million ± $200 million as at 31 December 1999, including the value of New Facilities Investment associated with the Stage 3A enhancement of the pipeline.

485. Accordingly, Epic Energy's proposed Initial Capital Base of $2,570.34 million as at 31 December 1999, derived from the costs incurred by Epic Energy in purchase of the DBNGP, is substantially in excess of DAC and DORC values of the pipeline and therefore outside of the "normal" range of values contemplated by section 8.11 of the Code to apply in establishing the Initial Capital Base for a pipeline that was in existence at the time of commencement of the Code.

486. I accept that in the particular circumstances that apply to the DBNGP the value of the Initial Capital Base is not constrained by section 8.11 of the Code and the value should be determined with consideration to values that fall outside of the range of DAC and DORC values.

487. In my view, Epic Energy's proposed Initial Capital Base is consistent with the objective of section 8.1(a) of the Code – that a Reference Tariff and Reference Tariff Policy should be designed with a view to providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that service.

488. However, in my view the proposed Initial Capital Base is inconsistent with other objectives of section 8.1(b), (d) and (e) to the extent that these objectives relate to matters of economic efficiency in the pricing of Reference Services. While an objective of section 8.1(b) may accommodate a tariff derived from a value of an Initial Capital Base that is in excess of efficient costs to the extent that it allows for recovery of past investment that was reasonable and sensible at the time the investment was made, I have found that the purchase price paid for the DBNGP did

not reflect a reasonable commercial judgment given the information available to Epic Energy at the time of the sale. In these circumstances, in my view, valuation of the Initial Capital Base at the purchase price paid by Epic Energy would be inconsistent with the objectives of section 8.1(b).

489. In view of the conflicting objectives of section 8.1, I now apply the factors set out in section 2.24 of the Code as fundamental considerations in my assessment of the Initial Capital Base. The matters and circumstances that are relevant to these fundamental considerations include:

- all of the circumstances of the sale of the DBNGP and in particular the conduct of the Sale Process;
- Epic Energy's purchase price for the DBNGP and whether the price was based on a sound commercial assessment of value in the circumstances then prevailing and anticipated;
- Epic Energy's financial viability and interests in ongoing ownership, and safe and reliable operation, of the pipeline;
- the expectations and interests of Users and Prospective Users in a Reference Tariff determination under the Access Arrangement;
- the public interest in a Reference Tariff outcome under the Code; and
- achieving a Reference Tariff outcome under the Access Arrangement that is conducive to future investment in the pipeline and development of the market for gas.

490. In its submissions to me, Epic Energy sought to justify its proposed value of the Initial Capital Base principally by reference to section 2.24(a) of the Code, which provides that the Regulator must take into account the Service Provider's legitimate business interests and investment in the Covered Pipeline.

491. In regard to the Sale Process of the DBNGP, I have made reference to the stated policy objectives of the Government in respect of tariffs for the DBNGP subsequent to the sale, both for a transition period to 1 January 2000 and subsequent to 1 January 2000, at which time it was expected that a tariff would be determined by a regulator under the Code. The Government's policy position was clearly expressed to prospective bidders and to the public in the period leading up to the sale: there would be a stepped decline in the full-haul tariff for the DBNGP with the decline consistent with an expectation that the tariff at 1 January 2000 would be established under the Code at a level of about $1.00/GJ.

492. As I have indicated in relation to my consideration of the Sale Process, however, I am satisfied on the basis of Epic Energy's uncontradicted evidence of statements by representatives of the Government could have led a reasonable person making a bid for the pipeline to attach some weight to the prospect of a headline full-haul transmission tariff of $1.00 per GJ as an approved regulated tariff under the Code as of 1 January 2000.

493. At 1 January 2000, an approved Access Arrangement under the Code was not in place for the DBNGP. As a consequence there was no tariff established under the Code, as was envisaged at the time of the sale. On 1 January 2000, the Government introduced a full-haul, 100 percent load-factor tariff for the T1 Service of $1.00/GJ. The establishment of the $1.00/GJ tariff at 1 January 2000 was entirely consistent with the Government's policy position on tariffs at the time of the sale, information provided to prospective bidders, and public statements made by the Government prior to, at the time of, and subsequent to the sale.

494. It is therefore my view that a factor to be accorded substantial weight in consideration of the Reference Tariff for the DBNGP and in consideration of the value of the Initial Capital Base is the Government's stated expectation and subsequent position of a $1.00/GJ tariff applying from 1 January 2000, with that tariff being the 100% load-factor tariff for a full-haul T1 Service.

495. Notwithstanding the above, I am not convinced on the basis of the evidence before me with respect to Epic Energy's purchase price for the DBNGP that the value of Epic Energy's bid for the DBNGP was affected by any representations or statements by the Government as to the tariffs that may apply under the Code subsequent to 1 January 2000.

496. This is because the tariff path proposed by Epic Energy as part of its bid for the DBNGP included tariffs that were different from the $1.00/GJ envisaged by the Government as applying at 1 January 2000. The tariff proposed by Epic Energy was a combination of a $1.00/GJ to Perth and "greater than $1.00/GJ" tariff to locations south of Kwinana Junction, rather than a $1.00/GJ full-haul tariff. The tariff proposed by Epic Energy was also based on a different tariff structure than the tariff for the T1 Service as specified by the Dampier to Bunbury Pipeline Regulations 1998, with the $1.00/GJ tariff proposed by Epic Energy for gas delivery to Perth being, in practical effect, a significantly higher tariff than the $1.00 tariff of the T1 Service, in a situation where gas is transmitted for a User at less than 100 percent load factor. The proposed tariff was inconsistent with the statements of expected tariffs made during the Sale Process by the GPSSC and the Government.

497. Further, the material available to me shows that Epic Energy was aware of the nature of the assessment that was likely to be undertaken by the Regulator in approving an access arrangement under the Code and received advice as to strategies that might be followed in order to maximise the tariff that might be established according to that process.

498. In all these circumstances, I do not consider there to be reason to give substantial weight to Epic Energy's proposed tariff path in my consideration of the Reference Tariff and Initial Capital Base under the Code.

499. I also note, in regard to Epic Energy's purchase of the DBNGP, my earlier statement that I am not satisfied that Epic Energy gave material consideration to any value of the Initial Capital Base other than a DORC value in its modelling of the value of the pipeline or in determining a value for Epic Energy's final bid. Moreover, information

provided to me by Epic Energy,[122] and confirmed in further studies,[123] indicates that it has been the usual case for the sale price of regulated gas transmission pipelines and distribution systems in Australia to be substantially in excess of the regulatory value of the relevant assets, with ratios of sale value to regulatory value typically in a range of 1.5 to 2.5. The ratio of the sale price of the DBNGP to the regulatory value contemplated by Epic Energy at the time of the sale is entirely consistent with these observations.

500. I have also found in my reasons that, for the purposes of the Code, the price paid for the DBNGP did not reflect reasonable commercial judgment by Epic Energy and/or Epic Energy's advisors insofar as it appears that, in deriving the assessed value and purchase price, no or insufficient consideration was given to substantial downside risk in the rate of return that may be approved by a regulator. I am of the view that a prudent and objective assessment of a future independent regulator's likely position on the rate of return – based upon information available at the time – should have identified this risk as a substantial one. Even if this was a matter where Epic Energy relied on the advice of its advisors, in balancing the interests of Epic Energy and the interests of Users and the public interest, I am of the view that Users should not have to bear the cost of the failure to identify this risk.

501. For all of the above reasons, in assessing the sale price for the purpose of establishing the Initial Capital Base under the Code, I am of the view that Epic Energy's purchase price was not based on a sound commercial assessment of its value in all the circumstances surrounding the sale.

502. In regard to Epic Energy's interests in ongoing ownership and operation of the DBNGP, I have considered submissions made to me by Epic Energy that establishment of the Initial Capital Base at a value less than the purchase price, and establishment of values of the Reference Tariff at a level less than proposed for the Access Arrangement, will have an adverse financial impact on Epic Energy sufficient to threaten its financial viability and limit the ability of Epic Energy to operate the pipeline in a safe and reliable manner. Epic Energy and other parties have made submissions to me indicating that threats to the financial viability of Epic Energy also constitute risks to other parties, including parties with current contracts for gas transmission. As such, there may be a broader interest of Users of the DBNGP and a public interest in the future financial viability of Epic Energy.

503. I accept that the values determined for the Initial Capital Base and Reference Tariff established under the Access Arrangement can have an effect on the financial viability of Epic Energy. However, I recognise that financial viability is also contingent upon many other factors that are beyond the direct impact of Reference Tariffs, including Epic Energy's own financial management, the possibility of equity injections into the company and growth in the market for gas transmission. In circumstances where I have found that Epic Energy's purchase price was not based on sound commercial assessment, consequences of this for financial viability should be given less weight in balancing Epic Energy's legitimate business interests against the interests of Users

[122] Epic Energy (WA) Transmission Pty Ltd, February 2003, Submission CDAP#1.

[123] Annexure to Affidavit of Gregory John Houston in the Supreme Court of Western Australia No. 2166 of 2001.

and the public interest in having competition in markets and in a supply of competitively priced gas.

504. In regard to the reasonable expectations and interests of Users and Prospective Users, I refer to my previous discussion of the Sale Process and the statements by the Government at that time in respect of tariffs for the DBNGP, subsequently given weight by the Government's introduction by regulation of a full-haul tariff of $1.00/GJ on 1 January 2000. These circumstances, and submissions made to me by Users and other parties, lead me to give weight to a reasonable expectation by Users and Prospective Users of a tariff determined under the Code consistent with the Government's stated expectations.

505. The interests of Users and Prospective Users of the DBNGP coincide with the interests of end-users of gas and the broader public interest in having prices for gas transmission services reflect the efficient cost of pipeline assets in a workably competitive market. I have found that the Initial Capital Base proposed by Epic Energy substantially exceeds any premium for risk and past investment that a workably competitive market might allow to be recovered. An Initial Capital Base substantially in excess of that which would prevail in a workably competitive market – as proposed by Epic Energy – exposes Users and Prospective Users to a long term outlook of gas transmission prices in excess of levels consistent with economic efficiency and a risk of a substantial increase in gas transmission tariffs at some time in the future, with adverse flow-on effects to end-users of gas and to the public.

506. Finally, I address the matter of achieving a Reference Tariff outcome under the Access Arrangement that is conducive to future investment in the pipeline and development of the market for gas.

507. Epic Energy has submitted to me that to establish the Initial Capital Base and Reference Tariffs at levels less than proposed would lead to a reduced incentive and capability to invest in the pipeline, and an inability to invest in extensions and expansions to the pipeline while maintaining tariffs for new Users at the Reference Tariff.

508. The Code explicitly addresses matters related to extensions and expansions of Covered Pipelines. The Code provides for the recognition of New Facilities Investment of the Service Provider in the Capital Base and Reference Tariffs for the Pipeline, and recognises the prospect of Capital Contributions from Users to finance extensions and expansions. These provisions of the Code address the incentives for investment in pipelines by both Service Providers and Users, in particular by providing for a Service Provider to obtain a return on new investment through the Reference Tariff, or through Surcharges. I note that for the current Access Arrangement Period, Epic Energy has not proposed any New Facilities Investment associated with extensions or expansions of the Pipeline, other than finalisation of the Stage 3A expansion in 2000.

509. It is my view that future development of the pipeline depends upon the financial viability and adequate cash-flows for Epic Energy, and that these should be recognised, to a reasonable extent, in establishing the Capital Base and Reference Tariffs. Other than this, however, I consider that incentives for investment are

adequately addressed by other provisions of the Code unrelated to the establishment of the Initial Capital Base and determination of an initial Reference Tariff.

510. I am of the view that in establishing both the Initial Capital Base and the Reference Tariff for this first Access Arrangement Period, a significant consideration is a value of the Initial Capital Base that would be consistent with the full-haul tariff of $1.00/GJ for the T1 Service at 1 January 2000, given weight by the actions of government both during and after the Sale Process.

511. I have made an assessment of a value of an Initial Capital Base that would be consistent with a Reference Tariff that would be expected to generate the same notional revenue over the first Access Arrangement Period as would be delivered by the tariff for the T1 Service put in place by the Gas Pipelines Access (Privatized DBNGP System) (Transitional) Regulations 1999 as of 1 January 2000 ("benchmark tariff"). In making this assessment I have assumed that:

- the benchmark tariff is escalated at a rate of two-thirds of the rate of change in the Eight Capital City, All-Groups Consumer Price Index as published by the Australian Bureau of Statistics ("**CPI**"), with a 2.75 percentage point reduction in the CPI applicable to the determination of tariffs for the year 2001 to correct for the inflationary impact of introducing the goods and services tax;[124]
- the notional revenue corresponding to this benchmark tariff is derived on the basis of the following assumptions:
  - all Users, including Users under exempt contracts, pay the benchmark tariff, and
  - the tariff is inclusive of charges relating to user-specific facilities; and
- volumes of gas transported, the capacity reservations and load factors are as forecast by Epic Energy for the Access Arrangement Period.

512. I have estimated that the value of notional revenue that would have been generated by the benchmark tariff for the Access Arrangement Period is $936 million in dollar values of 31 December 1999.

513. In order to undertake the calculation of an Initial Capital Base value from this notional revenue it is necessary to assign values to the other cost-of-service parameters for New Facilities Investment, Rate of Return and Non Capital Costs. For reasons already expressed, I find that these values for the parameters are the values that should be adopted for the Access Arrangement to conform to the requirements of the Code.[125] Using these values and a straight-line depreciation of the Capital Base according to asset lives as indicated in paragraph 343 of this Final Decision, and apportioning of the value of the Initial Capital Base across asset classes is in the same proportions as for Epic Energy's proposed Initial Capital Base, I estimate that a value of the Initial

[124] For the purposes of calculating the tariff escalation factor the September quarter CPI is used.

[125] Paragraphs 309, 330, 349.

Capital Base consistent with the notional revenue and these other cost parameters would be in the order of $1,525 million.

514. In determining a value of the Initial Capital Base I have given attention to the circumstances of Epic Energy's purchase of the DBNGP, the merits of a value close to DORC for reason of consistency with the efficiency objectives of section 8.1, the interests of Users of the pipeline and end-users of gas in competitive pricing of transmission services into the future, and the concerns expressed by Epic Energy as to its financial viability and Epic Energy's consequent interest in having a value in excess of DORC. My consideration of these matters involves a balancing of competing interests of different parties. Taking all the matters I have referred to in my decision into account, and recognising the fundamental significance of the factors in section 2.24, it is my determination that the Initial Capital Base for the DBNGP should be established at a value of $1,550 million as at 31 December 1999, including the value of capital costs associated with the Stage 3A enhancement of the DBNGP.

515. Using this value of the Initial Capital Base, and with values of forecast New Facilities Investment, Rate of Return and Non Capital Costs that should be adopted for the Access Arrangement to confirm to the requirements of the Code,[126] I have calculated the Total Revenue for the Access Arrangement Period, indicated as follows. This Total Revenue assumes an allocation of the Initial Capital Base across asset classes in the same proportions as for Epic Energy's proposed Initial Capital Base, and a Depreciation Schedule derived from straight-line depreciation of assets with assumed asset lives as indicated in paragraph 343.

Revised Total Revenue
(31 December 1999 $million, year ending 31 December)

	2000	2001	2002	2003	2004
Return on Assets	114.70	112.38	110.29	108.23	105.88
Depreciation	37.76	37.97	38.29	38.63	38.85
Non Capital Costs	38.41	39.58	41.83	42.09	41.65
Total	**190.87**	**189.93**	**190.41**	**188.95**	**186.38**

516. The total value of Total Revenue for the Access Arrangement Period is $946.55 and the present value of this Total Revenue is $768.53 million in dollar values of 31 December 1999.

517. Any Reference Tariff from this Total Revenue, including the schedule of tariffs for different zones of the pipeline, will depend upon cost allocations and the structure of the tariff, which are to be determined by Epic Energy subject to a number of constraints that I discussed in relation to the Cost Allocation and Reference Tariff, and which I indicate in the Amendments section of this Decision. I have estimated that the average 100 percent load-factor tariff that would result from the Total Revenue is $0.95/GJ as at 1 January 2000 and $1.01/GJ as at 1 January 2003.

[126] Paragraphs 309, 330, 349.

518. This average tariff for the Firm Service of $1.01/GJ as at 1 January 2003 corresponds to a tariff for the T1 Service of $1.08 and represents a 5.1 percent increase in the full-haul T1 Service tariff of $1.02/GJ that was introduced on 1 January 2003 and currently applies.[127]

519. In regard to Incentive Mechanisms, I consider that the relevant principles of sections 8.44 to 8.46 of the Code are met by the Incentive Mechanisms inherent in Epic Energy's proposed price path for the Reference Tariff and the provision for many Non-Reference Services to comprise Rebatable Services.

Terms and Conditions

520. Section 3.6 of the Code requires that:

> An Access Arrangement must include the terms and conditions on which the Service Provider will supply each Reference Service. The terms and conditions included must, in the relevant regulator's opinion, be reasonable.

521. Epic Energy has provided terms and conditions in a single document as Annexure B of the proposed Access Arrangement: the Access Contract Terms and Conditions.

522. Epic Energy's Access Contract Terms and Conditions sets out the terms and conditions for provision of the proposed Firm Service. The terms and conditions are set out in clauses relating to the following matters.

1. Interpretation
2. Gas Specifications
3. Receipt Points and Delivery Points
4. Nominations
5. Overrun
6. Imbalances
7. Peaking
8. Invoicing and Payment
9. Rights of Epic Energy
10. Control, Possession and Title to Gas
11. Notional Delivery Points
12. Metering
13. Liability
14. Curtailment and Interruption
15. Force Majeure
16. Charges
17. Default and Termination
18. Dispute Resolution and Independent Experts
19. Assignment
20. Confidentiality
21. Representations and Warranties

[127] *Gas Pipelines Access (Privatized DBNGP System) (Transitional) Regulations 1999*.

22. Records and Information
23. Insurances
24. No Waiver
25. Entire Agreement
26. Severability
27. Entry and Inspection
28. Ownership, Control, Maintenance and Risk
29. Rebate Sharing Contract
30. No Common Carriage
31. Epic Energy not a Supplier of Gas
32. Stamp Duty
33. No Third Party Benefit

523. In determining whether to approve the proposed Access Arrangement it is incumbent upon me, under the provisions of section 3.6 of the Code, to come to a view on whether the proposed terms and conditions set out in the Access Contract Terms and Conditions are reasonable. To do this, I have considered submissions on the proposed terms and conditions, independently reviewed the terms and conditions, and, where necessary to assist me in understanding the proposed terms and conditions and the potential impacts of these, engaged in discussions with various parties that have made submissions, including with Epic Energy. My deliberations and views on various clauses of the terms and conditions are indicated below, in the same order as the clauses appear in the Access Contract Terms and Conditions.

524. Before examining specific clauses of the Access Contract Terms and Conditions, however, I refer to clause 10 of the proposed Access Arrangement, which relates generally to terms and conditions. Sub-clauses 10.3 and 10.4 of the proposed Access Arrangement make provision for Epic Energy to vary certain provisions of the Access Contract Terms and Conditions without the consent of Users or the Regulator.

525. While Epic Energy has provided terms and conditions for the Firm Service as an annexure to the proposed Access Arrangement, the terms and conditions comprise part of the Access Arrangement. A change to the terms and conditions constitutes a change in the Access Arrangement.

526. Section 2.49 of the Code provides that:

> An Access Arrangement that has become effective may be changed only pursuant to this section 2 or pursuant to the implementation of an Approved Reference Tariff Variation Method as provided for in sections 8.3B to 8.3H.

527. Section 2 of the Code does not provide for changes to an Access Arrangement by unilateral decision of the Service Provider. It is therefore my view that provision under sub-clauses 10.3 and 10.4 of the proposed Access Arrangement for Epic Energy to vary certain terms and conditions without consent of the Regulator is not compliant with the Code.

528. As a further general matter relating to the Access Contract Terms and Conditions, a submission to me has indicated that neither the Access Arrangement nor the Access Contract Terms and Conditions contain a provision that expressly states that Epic Energy is under an obligation to accept and deliver gas, although there are provisions

such as sub-clause 9.4 of the Access Contract Terms and Conditions that refer to "an obligation to deliver gas". It is my view that it would be reasonable for the terms and conditions for the Firm Service to contain a provision that more explicitly states that Epic Energy is under an obligation to accept and deliver gas.

529. I move now to consider specific clauses and provisions of the proposed terms and conditions for the Firm Service.

530. I refer first to clause 1 of the Access Contract Terms and Conditions (Interpretation) that provides definitions of terms used in the Access Contract Terms and Conditions and sets out matters of construction. In sub-clause 1.1 of the Access Contract Terms and Conditions, Epic Energy defines "independent expert" as the expert appointed under sub-clause 16.2. This appears to be an error of cross-referencing as sub-clause 18.2 would appear to be the relevant provision in relation to the appointment of an expert.

531. Clause 2 of the Access Contract Terms and Conditions relates to the gas-quality specification for gas able to be shipped under the Firm Service, and provisions relating to the acceptance of out-of-specification gas. A gas quality specification is provided in schedule 2 to the Access Contract Terms and Conditions.

532. The proposed gas quality specification is the same as was established by the 1998 Access Manual, approved by the Coordinator of Energy under the *Dampier to Bunbury Pipeline Regulations 1998*, with the exception of an increase in the maximum temperature for gas delivered to inlet points: increased to 50 degrees Celsius from 45 degrees Celsius specified in the Access Manual.

533. While gas quality in the DBNGP is currently regulated under the *Dampier to Bunbury Pipeline Regulations 1998*, these regulations will fall away once an approved Access Arrangement is in place for the DBNGP. In the absence of other regulatory intervention by the State, such as through new regulations under the *Dampier to Bunbury Pipeline Act 1997*, regulatory oversight of the gas quality specification for the DBNGP will fall to the Independent Gas Pipelines Access Regulator in the function of approving the Access Arrangement and any revisions to the Access Arrangement.

534. In this context, I have given attention to the gas-quality specification proposed by Epic Energy as part of the terms and conditions of the Firm Service.

535. As noted above, the Access Manual approved under the *Dampier to Bunbury Pipeline Regulations 1998* establishes a gas-quality specification for the DBNGP. Epic Energy has adopted the same specification under the proposed terms and conditions for the Firm Service. The *Dampier to Bunbury Pipeline Regulations 1998* also set out a "broadest specification" for gas quality that is less stringent (i.e. wider) in respect of the maximum concentration of inert gases, minimum higher heating value, Wobbe Index and – subsequent to 1 July 2005 – maximum extractable LPGs.

536. The State Government has indicated a general intent to move towards the broadest gas specification through the declaration of this specification in the *Dampier to Bunbury Pipeline Regulations 1998*, but has refrained from adopting a policy position on a timetable for a transition. Regulation 24 of the *Dampier to Bunbury Pipeline*

Regulations 1998 indicates that any amendment to the existing gas quality specification would only occur through a further process of consultation with interested parties.

537. Several submissions made to me in respect of the proposed Access Arrangement put forward a view that the gas quality specification for the Firm Service should either be widened, or at least that the Access Arrangement for the DBNGP make provision for the future widening of the gas quality specification. The widening of the gas specification is sought for the purposes of eliminating the requirement for gas to contain a minimum content of LPGs, and to allow gas from a greater number of sources to be transported via the DBNGP to markets in the south west of the state.

538. Further submissions opposed widening of the gas specification on the basis that it reduced the quality of the gas as a feedstock in chemical manufacturing processes or that it would deprive some Users of contractual rights to take delivery of gas of a specified quality.

539. Epic Energy has itself indicated that it is keen to move to the broadest specification, but has noted that there are a range of complex issues associated in widening of the gas specification including the disposition of current contractual obligations in respect of gas quality, and impacts on the capacity of the DBNGP of a widening of the gas quality specification to allow transmission of gas of lower energy density. Epic Energy has also submitted that actions of the Government to regulate or otherwise secure a change in the gas quality specification of the DBNGP is more appropriately an action taken by the Coordinator of Energy established under the *Energy Coordination Act 1994* than by the Regulator established under the *Gas Pipelines Access (Western Australia) Act 1998*.

540. The principal limitation on introduction of a wider gas quality specification to the DBNGP is the contractual obligations of Epic Energy in respect of the quality of gas delivered to the Wesfarmers LPG plant, which gives rise to the minimum LPG content in the gas quality specification. This contractual obligation persists until 1 July 2005, which is beyond the end of the Access Arrangement Period proposed by Epic Energy (proposed to extend to 31 December 2004). Taking this into account, I am of the view that it is reasonable for Epic Energy to maintain the gas quality specification established under the Access Manual for this initial Access Arrangement Period. Consideration of the gas quality specification for future Access Arrangement Periods, taking into account opportunities that may arise for widening of the specification, is a matter to which consideration will need to be given at the time the Access Arrangement is reviewed.

541. While a gas quality specification is proposed for the Firm Service, Epic Energy does make provision in the Access Arrangement for acceptance of out-of-specification gas. Clause 2.3 of the Access Contract Terms and Conditions indicates:

> Epic Energy may agree with the Shipper to accept out-of-specification gas from the Shipper prior to that gas entering the DBNGP, on terms and conditions acceptable to Epic Energy.

542. I received a submission in respect of this clause, indicating that the terms and conditions on which Epic Energy may agree to accept out-of-specification gas must be reasonable.

543. Epic Energy submitted that the imposition of a "reasonableness" requirement is, in these circumstances, inappropriate for three reasons:

- it does not provide any greater certainty to shippers, as any acceptance of out-of-specification gas is subject to negotiation, with recourse to arbitration if necessary;
- Epic Energy should have discretion over accepting out of specification gas into the pipeline; to limit its discretion could compromise safe and reliable operation and would result in an Access Arrangement including such a provision which could not be approved by the Regulator in accordance with section 2.24(c) of the Code; and
- it fails to properly recognise the pre-existing contractual requirements imposed upon Epic Energy in relation to gas specification.

544. Taking into account the submissions of Epic Energy, I am of the view that the provision for Epic Energy to maintain discretion over the acceptance of out-of-specification gas is reasonable.

545. Sub-clause 2.4 of the Access Contract Terms and Conditions provides that a User delivering out-of-specification gas to the DBNGP shall pay Epic Energy a surcharge calculated by multiplying each GJ of out-of-specification Gas by the Out of Specification Gas Charge, which is set at a rate of $15 for each gigajoule of out-of-specification gas.

546. The Out of Specification Gas Charge is of the nature of a penalty, with the implied purpose of discouraging delivery of out-of-specification gas to the DBNGP. I do not consider a penalty of this nature to be unreasonable.

547. The proposed rate of the Out of Specification Gas Charge ($15/GJ) is a penalty rate proposed by Epic Energy in relation to a number of penalty charges provided for under the Access Contract Terms and Conditions, including also the Nominations Surcharge, the Excess Imbalance Charge, the Peaking Surcharge, and the Unavailability Charge. Several submissions made to me expressed a view that the level of these penalty charges is unreasonably high and punitive, and indicated that the charges should be set at levels consistent with the additional costs that would be incurred by Epic Energy as a result of the relevant acts that attract the charges.

548. Provision under the Access Contract Terms and Conditions for the same penalty rate of $15/GJ to apply for many different forms of non-compliance with the Access Contract Terms and Conditions suggests that the penalty rate is not based on additional costs that may be incurred by Epic Energy as a result of non-compliance with the Access Contract Terms and Conditions, but rather is a punitive charge.

549. Epic Energy has submitted to me that the proposed penalty rate (that is equivalent to about 1500 percent of the 100 percent load factor tariff) is not out of the ordinary, if penalty rates for pipeline systems in the USA are considered. Epic Energy has also indicated that penalties of such a magnitude are necessary to deter unsatisfactory behaviour amongst Users, and to require Epic Energy to reduce this rate would reduce the ability of Epic Energy to protect itself and would fail to give due consideration to balancing interests as required by section 2.24 of the Code.

550. In assessing the reasonableness of the general level of penalty rate that is proposed to apply generally to the proposed penalty charges, I have given consideration to common practice of the gas transmission industry in respect of such charges.

551. Penalty charges for transmission pipelines are typically in the range of 1.2 to 5 times the value of the relevant Reference Tariff, with an average of about 2.5. In this regard, the penalty rate proposed by Epic Energy is substantially in excess of what may be regarded as reasonable on the basis of common practice in the industry. In the absence of any substantiation of higher charges, I am of the opinion that the rate of penalty charges proposed by Epic Energy is not reasonable.

552. An exception to this exists, however, in regard to the proposed Unavailability Charge, provided for under sub-clause 5.4 of the Access Contract Terms and Conditions. Liability of Users to the Unavailability Charge is unlikely to arise in the normal course of events of operation of the pipeline or use of services, and liability for the charge would only arise after issue to the User of an Unavailability Notice. As Unavailability Notices are likely to be issued in circumstances of emergency or other severe disruption to pipeline operations, a relatively large penalty for failure to comply with an Unavailability Notice is arguably appropriate. On the basis of these factors, I consider the rate of $15/GJ to be reasonable in respect of the Unavailability Charge.

553. A final matter related to gas quality is the maximum limit on the temperature of gas able to be delivered to the pipeline. In submissions to the Regulator, the North West Shelf Gas Joint Venture indicated opposition to the proposed maximum limit on temperature of gas entering the pipeline (50°C) which is less than the limit under its existing contract with Epic Energy (60°C) but greater than the existing limit specified in the *Dampier to Bunbury Pipeline Regulations 1998*. North West Shelf Gas submitted that the maximum limit on gas temperature should be increased to 60°C so as to not result in greater costs through upgrade of the joint venture's gas treatment facility and to ensure that clients of the joint venture are not precluded from access to the DBNGP under the terms and conditions of the Access Arrangement. Further, North West Shelf Gas submitted that a maximum limit on gas temperature of 60°C was supported by past studies, and a lack of evidence for any adverse effect on pipeline integrity from higher gas temperature to date.

554. From the information presented to me, I understand that the maximum limit on gas temperature is an issue of particular importance to the North West Shelf Gas Joint Venture. I further understand that Epic Energy own and operate a gas cooling facility close to the Receipt Point for gas from the Domgas plant.

555. I am aware that a maximum inlet temperature for gas delivery to transmission pipelines of 50°C is consistent with common industry practice, and that there is some concern amongst pipeline operators that gas temperatures greater than this limit may adversely affect pipeline integrity. The proposed maximum inlet temperature for the Firm Service need not affect pre-existing contractual rights of any party and it is open for Users that may wish to deliver gas to the DBNGP that does not meet this temperature limit to either undertake gas cooling themselves or negotiate alternative arrangements with Epic Energy, such as purchase of a gas-cooling service from Epic Energy as an ancillary service. Taking these matters into account, and with reference

to the factors of 2.24, including the operational and technical requirements necessary for the safe and reliable operation of the pipeline, I consider that the proposed maximum limit on gas temperature is reasonable. I note that there would be prospect in future reviews of the Access Arrangement to consider whether a gas-cooling service should be included in the Services Policy for the DBNGP.

556. Clause 3 of the Access Contract Terms and Conditions relates to Receipt Points and Delivery Points for the DBNGP, including:

- the supply and installation of Receipt Points and Delivery Points;
- levying of Delivery Point charges;
- the re-location of Delivery Point MDQ and effects on charges;
- flexibility in use of Receipt Points;
- allocation of gas at Receipt Points utilised by more than one User; and
- allocation of gas at Delivery Points used by more than one User.

557. While no submissions were received on the proposed Access Arrangement in respect of terms and conditions relating to Receipt Points and Delivery Points, I have given attention to clause 3.6 of the Access Contract Terms and Conditions that makes provision for allocation of gas received into the DBNGP at Receipt Points utilised by more than one User. Under paragraphs 3.6(b) and (c) of the Access Contract Terms and Conditions, in situations where more than one User supplies gas to Epic Energy at a single Receipt Point, each User is deemed to have delivered gas to Epic Energy in certain circumstances and to not have delivered any gas where no written confirmation of supply of gas has been provided by the User to Epic Energy by 0830 hours on the following day.

558. This provision in respect of Receipt Points contrasts with paragraphs 3.7(b) and (c), relating to situations in which more than one User takes delivery of gas at a single Delivery Point, under which there is scope for agreement between the relevant Users and, in the absence of such agreement, proportional allocation is permitted on the basis of nominated quantities.

559. Given that there is scope for agreements between Users in respect of supply of gas to shared Receipt Points (as with shared Delivery Points), I consider that it is not reasonable to assume as a matter of course that no gas has been delivered to Epic Energy in circumstances where written confirmation of supply of gas has not been received in respect of Receipt Points used by more than one User, but where it is known that gas has been delivered to that Receipt Point and the total amount of that gas is also known.

560. Clause 4 of the Access Contract Terms and Conditions relates to requirements for Users to make nominations of gas receipt and gas delivery quantities, including:

- provisions for Epic Energy to obtain information on likely nominations from Users;

- requirements for Users to provide weekly nominations;
- provisions for Users to amend nominations;
- requirements that Users make nominations in good faith; and
- provisions for Epic Energy to take action against Users if nominations are considered to be made other than in good faith and if gas quantities received or delivered vary from nominations by an amount in excess of an allowable limit.

561. Several submissions made to me indicated a concern that the nominations process was unduly inflexible particularly in respect of not allowing re-nominations within a gas day for that gas day. Submissions from Users expressed concern that this would result in an exposure of Users to penalty charges either as a result of actual gas deliveries differing from nominations due to circumstances arising in a gas day, or exposure to imbalance penalties. The latter may occur in a situation where nomination practices involve Users making nominations to Epic Energy of gas delivery volumes and then for Epic Energy to make nominations to the User's gas supplier (as opposed to the User itself making nominations to the gas supplier). In this situation, if a User takes delivery of gas in a different quantity than initially nominated, the absence of ability for the User to re-nominate would result in there being no re-nomination to the gas supplier and the User having a gas imbalance and a consequent exposure to imbalance penalties.

562. In written and verbal submissions to me, Epic Energy has indicated that neither of these concerns of Users is valid. Epic Energy re-iterated that liability for penalties in relation to nominations arises in the event that nominations are not made in good faith, regardless of whether ultimate gas receipt and delivery volumes depart from nominated volumes. Users maintain the right to take delivery of gas up to the limit of contracted MDQ regardless of nominations. In relation to potential exposure to imbalance penalties, Epic Energy has indicated to me that operation of the DBNGP involves Users making nominations directly to gas suppliers; hence the maintenance of gas balances is within the control of Users rather than the control of Epic Energy.

563. Taking account of the above, I am of the view that the absence of the ability of Users to re-nominate within a gas day does not give rise to any potential liabilities for Users and hence is not unreasonable.

564. The potential liabilities arising from failing to nominate in good faith arise from terms of sub-clause 4.4 of the Access Contract Terms and Conditions. Paragraph 4.4(b) of the Access Contract Terms and Conditions provides for Epic Energy to issue a Variance Notice to a Shipper if Epic Energy as a reasonable and prudent pipeline operator believes that the Shipper is not making nominations in good faith. A Variance Notice requires the Shipper to nominate in good faith. Paragraph 4.4(c) of the Access Contract Terms and Conditions provides for the Shipper to pay the Nomination Surcharge in the event that after 21 days from the issue of the Variance Notice, the quantities of gas received or delivered into or from the DBNGP on behalf of the Shipper varies by more than 10 percent of the Shipper's relevant nominations. The Nominations Surcharge is levied at a rate of $15/GJ of the difference between the nomination and the relevant quantity of gas received or delivered. The Nominations Surcharge remains in force until the Variance Notice is withdrawn, which may be at a

time at Epic Energy's discretion, or after the lapse of three consecutive months without the Shipper incurring the Nomination Surcharge.

565. In view of my consideration of the provisions of the Access Contract Terms and Conditions relating to nominations, I have no in-principle difficulty with the proposed Nominations Surcharge. I do, however, regard the proposed rate of the Nominations Surcharge to be unreasonable, as discussed previously (paragraphs 547 to 551).

566. Clause 5 of the proposed Access Contract Terms and Conditions deals with overrun of a User's gas delivery in excess of that User's MDQ and contains provisions relating to:

- Overrun charges;
- interruptibility of gas deliveries that constitute overrun; and
- liabilities of a User taking overrun if the taking of that overrun causes Epic Energy to interrupt delivery to another User.

567. A submission made to me raised three matters of concern regarding terms and conditions relating to overrun.

568. The first issue raised relates to the definitions of "MDQ" and "Delivery Point MDQ" in the Access Contract Terms and Conditions, and whether a User's MDQ (for the purposes of determining an overrun quantity) includes capacity purchased on a temporary basis, such as through the proposed Secondary Market. In examining this matter, I have noted that "MDQ" means the aggregate of a User's Delivery Point MDQs, which in turn means the maximum quantity of gas that the User may require Epic Energy to deliver on a day at a single Delivery Point, as specified in the Access Contract. Under clauses 5.1 and 5.2 of the Access Contract Terms and Conditions, "overrun" is defined as gas delivered to a User which is in excess of the User's Delivery Point MDQ or, where gas which is delivered to various Delivery Points, the gas in aggregate exceeds the User's MDQ. Where a User acquires additional delivery capacity (through the Secondary Market or otherwise), that additional capacity will form part of the User's MDQ. Accordingly, the overrun provisions would not be triggered.

569. The second and third issues relate to potential liability of Users for losses or damages incurred by Epic Energy from overruns. It was submitted to me that such liability may be unreasonable where Users are not given notice or an opportunity to correct overruns.

570. There may be practical difficulties in Epic Energy providing timely notice to a User of an overrun since an overrun relates to a single day and is measured at the end of each day, hence is only known *ex post*. With regard to the potential for a User to incur a liability arising from an overrun, I have noted that under clause 5.3 of the Access Contract Terms and Conditions, Epic Energy has the discretion to interrupt a service to an offending User and provides for the User to assume liability for any loss or damage or costs incurred by Epic Energy as a result of the User taking an overrun. These provisions may be reasonable in so far as the User has no contractual entitlement to an overrun. It may also be reasonable for the User to bear the costs of

operating outside of contract provisions. However, I consider that it is contrary to the reasonable interests of Users for the offending User's liability to be unlimited. It is my view that a reasonable balancing of interests of Epic Energy and Users would entail Epic Energy and other Users being obliged to take all reasonable steps possible to mitigate the loss that may occur in the event of a User taking an overrun.

571. Sub-clause 5.2 of the Access Contract Terms and Conditions provides for a User to pay Overrun charges in certain circumstances where the quantity of gas delivered on behalf of that User exceeds that User's MDQ.

572. Provision for an Overrun Charge is common practice in the gas transmission industry, and such a charge has to date been applied for the DBNGP under the *Gas Transmission Regulations 1994* and the *Dampier to Bunbury Pipeline Regulations 1998*. Further, the Overrun Charge proposed by Epic Energy for the DBNGP is generally similar in both operation and magnitude to the Overrun charges applying or previously applying under these regulations, being calculated at either 110 percent of relevant capacity charges, or 110 percent of the highest price for capacity on the Secondary Market for the relevant day. In view of this, I have no reason to consider the provision to be unreasonable.

573. Clause 5 of the Access Contract Terms and Conditions also makes provision for an Unavailability Charge, which is a charge levied in respect of gas taken contrary to an Unavailability Notice issued to a User by Epic Energy. As already indicated in this Final Decision (paragraph 552) I consider provision for the Unavailability Charge to be reasonable.

574. Clause 6 of the Access Contract Terms and Conditions relates to Imbalances and provides for, *inter alia*, an obligation on Users to maintain gas balances within limits, and penalty charges to apply in the event of Imbalances outside of these limits.

575. Epic Energy has proposed an Imbalance Limit for a User of two percent of the User's MDQ, and an Excess Imbalance Charge which is levied at a rate of $15 for each gigajoule by which the absolute value of a Shipper's daily imbalance exceeds the Imbalance Limit.

576. Several submissions made to me by Users and other parties have addressed the proposed Imbalance Limit and Excess Imbalance Charge, indicating that these are matters of substantial concern. The submissions addressed matters and put forward views, as follows.

- A penalty on imbalances is not necessary given provision in the proposed Access Contract Terms and Conditions for Epic Energy to curtail gas receipt or delivery for a User with an imbalance that may compromise the operation or integrity of the DBNGP (sub-clause 6.5), and indemnification of Epic Energy against direct and indirect damage if a User wilfully disregards its obligations under an Access Contract (sub-clause 13.2).

- Penalties for positive imbalances are unjustified as positive imbalances do not have adverse impacts on operation of the pipeline.

- The key criterion in setting any surcharge should be the operational impact of User imbalances on the DBNGP, and the overall state of imbalance on the DBNGP should be the paramount focus, not whether a particular individual User is out of balance.

- The proposed Imbalance Limit of two percent of a User's MDQ is more onerous than the present eight percent limit (under contracts entered into under the *Gas Transmission Regulations 1994*) and is difficult for Users to achieve, and is inconsistent with an industry standard of eight percent.

- The proposed provision for the Excess Imbalance Charge may potentially cause Users to be liable to the charge where an imbalance is caused by actions of Epic Energy in curtailing gas receipt or delivery, or the actions of another User, and there should be a provision removing all imbalance limits on gas days when Epic Energy has interrupted or curtailed a Shipper's capacity, as was the case under clause 184(2) of the *Gas Transmission Regulations 1994*.

- Users are limited in their ability to manage imbalances as a result of the absence of any requirement for Epic Energy to provide Users in a timely manner with sufficient information to assess imbalance positions, and the absence of provision for Users to make re-nominations during the course of a day, to obtain a Park and Loan Service as part of the Reference Service, to trade imbalances, or to maintain balances over a number of days rather than within a single day.

- Special balancing provisions currently exist for delivery of gas in the Pilbara region (upstream of Compressor Station 1), relating to arrangements for the apportionment of delivered gas between Hamersley Iron, Robe River Mining and Western Power, which operate to the benefit of Epic Energy and foster the efficient operation of the DBNGP, but which could give rise to liabilities for the Excess Imbalance Charge.

577. Epic Energy has responded to these submissions as follows.[128]

- Epic Energy acknowledges that the proposed imbalance tolerances are more restrictive than those that applied under the access regime of the *Gas Transmission Regulations 1994*, and that apply under the current regime. Moreover, Epic Energy understands that pipeline modelling to support the setting of imbalance tolerances immediately prior to the introduction of the access regime of the *Gas Transmission Regulations* indicated tolerances close to the two percent currently proposed, but were not acceptable to a "regulations committee" dominated by pipeline users. Major problems have not arisen with the wider limits because pipeline capacity has not been fully utilised for a significant part of the time since the *Gas Transmission Regulations* came into effect. That is probably an outworking of the tranche methodology used in those regimes.

- Subsequent studies of imbalance tolerances have continued to show the need for tighter imbalance limits as pipeline use approaches the available capacity. These studies have recognised the impact of Shippers' load diversity. They have also

[128] Epic Energy (WA) Transmission Pty Ltd, 12 May 2000, Submission 6.

recognised that, with a distribution of loads, there is a probability that coincident imbalances will prevent Epic Energy from delivering its contract entitlements if imbalance tolerances are too high.

- The fact that the proposed DBNGP Access Arrangement does not allow Shippers to trade imbalances has been recognised and Epic Energy is prepared to propose amendments to permit Shippers to trade imbalances.

- Epic Energy can point to examples in the USA where tolerances are two percent (for example Kern River Transmission). However, Epic Energy would caution against comparing imbalance tolerances across gas transmission pipelines. Differences in facilities, differences in utilisation, and differences in Shipper load patterns all contribute to differences in tolerance to Shipper imbalances. Furthermore, larger imbalances can be tolerated if the total capacity available for use by Shippers is reduced. However, reducing the available capacity will have the effect of increasing the price paid for that capacity.

578. I am of the view that, despite provisions in the Access Contract Terms and Conditions, that might otherwise provide for Epic Energy to manage imbalance, an imbalance charge is not unreasonable as a means of providing an incentive for Users to comply with contractual obligations in relation to imbalances and thus to reduce costs of pipeline operation. This includes provision for an imbalance charge on positive imbalances that, while not potentially as serious in terms of impacts on pipeline operation as negative imbalances, may affect the ability of other Users to deliver gas to the pipeline. However, it is not reasonable for Users to potentially incur liabilities for the Excess Imbalance Charge in circumstances where the Imbalance is caused by actions of Epic Energy.

579. The setting of imbalance limits for a pipeline is largely a matter of a balancing of interests between the Service Provider and Users. Low imbalance limits may be difficult for Users to meet, necessitating higher management inputs or incurrence of liabilities for surcharges, while high imbalance limits may, in the absence of other mechanisms to control imbalances, compromise the ability of the Service Provider to manage the pipeline and to reliably supply services. The imbalance limit of eight percent established for the DBNGP under the *Gas Transmission Regulations 1994* may be viewed as a particular, but not necessarily in any way superior, compromise between the interests of the Service Provider and Users.

580. That said, I have given attention to whether the eight percent imbalance limit established by the *Gas Transmission Regulations 1994* or the two percent limit proposed by Epic Energy may represent a reasonable balancing of interests. In this regard, there are characteristics of the DBNGP that might cause operation of the pipeline to be relatively tolerant of imbalances larger than two percent:

- the pipeline is not being operated at capacity, nor is forecast to be during the Access Arrangement Period;

- the pipeline has a relatively low ratio of daily imbalance volume to pipeline linepack; and

- the pipeline is operated as a highly compressed pipeline.

581. I also note that for at least two large Users of the DBNGP (Western Power and AlintaGas), gas deliveries are subject to factors outside of the User's control (particularly weather conditions) and gas balances within a two percent imbalance limit may be difficult to achieve on a day to day basis.

582. In addition, Epic has the right to refuse the acceptance of gas into the pipeline and to refuse gas delivery to the User, regardless of whether the imbalance for that user is below the limit within the Imbalance Limit (section 6.5 of the Access Contract Terms and Conditions). As such, imbalance charges can be viewed as an incentive for Users to be in balance rather than a means of maintaining system integrity.

583. In view of the above, I consider that the proposed Imbalance Limit of two percent of a User's MDQ is unreasonable.

584. In regard to an obligation on Epic Energy to provide information to Users in respect of imbalances, I note that sub-clause 6.3 of the Access Contract Terms and Conditions provides for this.

585. In response to submissions, I have also given attention to the special provisions for balancing that exist in relation to the delivery of gas to Delivery Points in the Pilbara region. These provisions will persist for the term of the relevant contracts rather than necessarily being negated by the Access Arrangement. Despite this, it is open for any Prospective User to negotiate particular arrangements, such as particular balancing arrangements, outside of the terms and conditions for the Reference Service. I thus see no reason to make such provisions part of the terms and conditions for the Reference Service.

586. As a final matter in relation to the Excess Imbalance Charge, I refer to my previous discussion of charges indicating that I regard the proposed rate of the Excess Imbalance Charge to be unreasonable (paragraphs 547 to 551).

587. Clause 7 of the Access Contract Terms and Conditions relates to peaking of gas deliveries, in particular:

- establishing a maximum hourly quantity (MHQ) for gas delivery;
- provision for Epic Energy to require that a user pay a Peaking Surcharge in the event that the User exceeds the User's MHQ; and
- providing for Epic Energy to refuse to deliver gas to a User at a Delivery Point at any time that the User exceeds the User's MHQ.

588. Paragraph 7.1(b) of the Access Contract Terms and Conditions provides for Epic Energy to charge a Shipper a Peaking Surcharge of $15 for each gigajoule of gas by which the Shipper has exceeded the Shipper's maximum hourly quantity.

589. Submissions made to me have indicated that peaking penalties have not previously been applied on the DBNGP, and that unlike the position under the existing contracts, Users will not be able to aggregate peaking imbalances across multiple receipt and Delivery Points.

590. The Peaking Limit proposed by Epic Energy of 120 percent of 1/24 of a User's MDQ is also consistent with common industry practice, and the Peaking Surcharge proposed by Epic Energy for delivery of gas to Users at Delivery Points is common practice in the Australian gas transmission industry. On this basis I consider that Epic Energy's proposed provision for a Peaking Surcharge and the proposed Peaking Limit are reasonable.

591. Epic Energy has proposed, however, to apply the Peaking Limit to individual Delivery Points. I consider that, for the DBNGP, this is an unreasonable restriction and it would be reasonable for the peaking limit to apply in aggregate across a User's Delivery Points within each pipeline zone for Zones 1 to 9, and on each lateral pipeline of the DBNGP in Zone 10.

592. I also consider the proposed magnitude of the Peaking Surcharge to be unreasonable, as discussed previously (paragraphs 547 to 551).

593. Clause 8 of the Access Contract Terms and Conditions contains provisions relating to invoicing and payment. Submissions made to me by Users drew attention to the requirement for payment of the Gas Receipt Charge and Pipeline Capacity Charge in advance and commented that:

- as the proposed Capital Base includes a component of working capital, the provision for payment in advance of the Gas Receipt Charge and the Pipeline Capacity Charge should be scrutinised to ensure that this does not have the effect of "double dipping"; and

- the provisions for payment in advance do not make allowance for variations in throughput or interruptions to supply as a result of force majeure events.

594. Contrary to submissions, Epic Energy has not proposed to include a component of working capital in the Initial Capital Base.

595. In regard to interruptions to supply as a result of force majeure events, I refer to the discussion of provisions of the Access Contract Terms and Conditions relating to force majeure (paragraph 618 of this Final Decision) and note that I consider it reasonable that the Access Contract Terms and Conditions should make provision for Epic Energy to waive applicable capacity charges where it claims force majeure has occurred. Payment of capacity charges in advance should not affect the operation of this provision, although it may require that the mechanism for the waiver be a credit to the account of affected Users rather than a reduction in an amount invoiced for the period of the interruption in the service.

596. Clause 9 of the Access Contract Terms and Conditions contains provisions relating to rights of Epic Energy in relation to operation of the DBNGP and meeting its obligations to deliver gas. No submissions received by me addressed these provisions and I have no reason to consider the provisions to be unreasonable.

597. Clause 10 of the Access Contract Terms and Conditions contains provisions relating to control, possession and title to gas. No submissions received by me addressed these provisions and I have no reason to consider the provisions to be unreasonable.

598. Clause 11 of the Access Contract Terms and Conditions makes provision for Notional Delivery Points, which are notional points of gas delivery from the DBNGP into a Gas Distribution System. Notional Delivery Points are defined for the purposes of determining charges for gas delivery to a distribution system, where that gas is actually delivered through multiple "real" Delivery Points. Sub-clause 11.5 of the Access Contract Terms and Conditions includes the following provision in relation to gas delivery to Notional Delivery Points on a distribution system:

> Where gas is delivered to a distribution system (to which the DBNGP is connected) by a gas transmission system other than the DBNGP, the quantities of gas measured at a Notional Delivery Point will need to take into account arrangements between Epic Energy, that other gas transmission system and the operator of that distribution network, and the requirement for any party delivering gas to Notional Delivery Points to take into account.

599. Two submissions received by me expressed concern about the absence of information on the nature of the "arrangements" referred to in this sub-clause. In my Draft Decision, I took the view that it is in the interests of Users and Prospective Users that the arrangements referred to be clearly described and their effect on the Access Arrangement explained. Moreover, I took the view that to the extent that arrangements may change over time as between operators and networks, Prospective Users should be advised of the relevant arrangements prior to becoming subject to any contractual obligation that may be affected.

600. Subsequent to issuing my Draft Decision, I have been advised by Epic Energy that sub-clause 11.5 has become redundant in view of the development of Interim Market Rules for full retail contestability of gas markets in Western Australia. Epic Energy has indicated to me that the Interim Market Rules establish the arrangements between operators of gas transmission systems and distribution networks referred to by clause 11.5, and that clause 11.5 can therefore be replaced by a reference to these arrangements and provision for Users and Prospective Users to be notified of these arrangements.

601. In view of these developments, I accept that it is not necessary for the Access Arrangement to provide further information on the arrangements referred to in sub-clause 11.5 of Access Contract Terms and Conditions. However, I still consider it to be in the reasonable interests of Users that the Access Contract Terms and Conditions provide for Epic Energy to advise Users and Prospective Users of the arrangements bought into being by the Interim Market Rules, and any arrangements that supersede the Interim Market Rules.

602. Clause 12 of the Access Contract Terms and Conditions relates to metering of gas receipt and deliveries to and from the DBNGP, including provisions relating to:

- the responsibilities of Users to install and maintain metering equipment at Receipt Points;
- the responsibilities of Epic Energy to install and maintain metering equipment at Delivery Points;
- the responsibilities of Epic Energy to calculate and record gas supplies and deliveries;

- the design, adjustment, operation and verification of metering equipment;
- requirements of Users to obtain Epic Energy approval of metering equipment at Receipt Points;
- the disposition of inaccurate metering equipment and the correction of inaccurate measurements; and
- the retention of metering records.

603. A submission made to me raised concerns as to the arrangements for correction of meter readings in the event that metering equipment is found to be registering inaccurately.

604. Sub-clause 12.6 of the Access Contract Terms and Conditions (paragraph 12.6(a) provides that:

> If at any time, any of the Metering Equipment is found to be registering inaccurately, it will be adjusted as soon as reasonably possible to its specification. The reading of such Metering Equipment will be corrected for any period of inaccuracy ("Correction Period") which is definitely known or agreed upon, provided that the Correction Period will not extend beyond one half of the time elapsed since the date of the Previous Verification.

605. The clause has the effect of limiting Epic Energy's liability in relation to inaccurate metering equipment to that associated with an error for one half of the time elapsed since the date of the previous verification, regardless of the period of time for which the metering error might be known or suspected to have occurred.

606. I take the view that the limitation on liability is unreasonable given that Epic Energy is responsible for supplying, installing, operating and maintaining metering equipment (sub-clause 12.2 of the Access Contract Terms and Conditions). However, I also recognise that there may be circumstances in which the period of inaccuracy cannot be known or agreed upon and that, in such circumstances, a qualification that the correction period will be set at one half of the time elapsed since the date of the previous verification may be appropriate.

607. I also observe that paragraphs 5(a) and (d) of schedule 3 of the Access Contract Terms and Conditions (relating to requirements for metering equipment) make reference to sub-clauses 11.5 and 11.6 of the Access Contract Terms and Conditions. Those references should be to sub-clauses 12.5 and 12.6 of the Access Contract Terms and Conditions.

608. Clause 13 of the Access Contract Terms and Conditions defines limits on liability for Epic Energy and a User that is party to an access contract. Clause 13 includes provisions relating to:

- a general limitation of liability for direct damage;
- liability in instances of fraud or wilful disregard in respect of obligations under the Access Contract;
- limitation of liability of Epic Energy in respect of approvals granted by Epic Energy; and

- responsibility of a User for the User's own and the User's contractors' personnel and property.

609. Submissions made to me expressed concerns with some of the limits on liability and in response to these submissions I have closely examined clause 13. In doing so, I have noted submissions made to me by Epic Energy, emphasising that clause 13 deals with the issue of causation: if the User causes the damage, it should be liable for it, irrespective of whether the damage is caused to Epic Energy, to some other User, or to another third party who has a contract with Epic Energy. Epic Energy has also provided information to me to clarify matters of apparent inconsistency between clauses.

610. After considering the information provided to me by Epic Energy, I am satisfied that the scope of liability for Users under clause 13 is not as broad as it may initially have appeared and that clause 13 does not impose undue liability on Users and related parties.

611. Clause 14 of the Access Contract Terms and Conditions makes provision for curtailment and interruption of transmission services, including:

- permissible interruptions (i.e. curtailments and interruptions that may occur without liability of Epic Energy to the shipper, including curtailments and interruptions as a result of force majeure events); and

- interruptions other than permissible interruptions.

612. Clause 14 also makes provision, in the event of a curtailment or interruption other than a permissible interruption, for the refund of relevant charges to affected Users.

613. Submissions made to me have indicated concern in relation to the ability of Epic Energy to curtail delivery of gas, and in relation to the permissible limit for interruptions to delivery.

614. Sub-clause 14.1 of the Access Contract Terms and Conditions states that Epic Energy may curtail or interrupt a User without liability, in such circumstances as Epic Energy considers necessary as a reasonable and prudent pipeline operator provided that the interruption or curtailment is within the "permissible limit", defined in the Access Contract Terms and Conditions as one percent of the Shipper's MDQ multiplied by the number of days in the year.

615. The "permissible limit" relates to the definitions of the Firm Service and Firm Service capacity. On the basis of information provided to me by Epic Energy, I am of the view that the methodology used by Epic Energy to define firm capacity is technically rigorous and the designation of the permissible limit is not greatly different from Epic Energy's current contractual commitments in relation to service reliability. On this basis, I consider the permissible limit established by Epic Energy to be reasonable.

616. Clause 14 of the Access Contract Terms and Conditions does not provide for the prior notification of Users where any planned maintenance activity is likely to interrupt gas transmission. This matter was addressed in sections 21 to 23 of the 1998 Access Manual, which required 90 days notice to be provided to Users in such circumstances.

I take the view that it is in the reasonable interests of Users that they be notified of potential for interruption of services where Epic Energy knows of this potential, and that the Access Contract Terms and Conditions should provide for this.

617. I also note that sub-clause 14.2(b) refers to a "Receipt Charge". This term is not defined in the Access Contract Terms and Conditions or in any of the other Access Arrangement documentation. A definition should be inserted, or, if the term "Gas Receipt Charge" is intended (a term which is defined), then the latter term should be used instead.

618. Clause 15 of the Access Contract Terms and Conditions makes provision for a Party to be relieved of obligations of performance under an Access Contract if the non-performance is a result of a force majeure event. Force majeure is defined in subclause 1.1 of the Access Contract Terms and Conditions as any event or circumstances not within the control of a party and which by the exercise of due diligence, that party is not able to prevent or overcome. A number of events or circumstances are explicitly indicated to not constitute events or circumstances of force majeure:

(a) changes in market structure, operations or conditions for:

(i) supply, purchase or sale of gas;

(ii) any good or service manufactured or provided by the Shipper;

(b) lack of, or reduction in, gas reserves, water supply or raw materials;

(c) commercial failure, expiration or termination for whatever reason of a contract;

(d) lack of funds/inability to pay money; or

(e) strikes or industrial disputes.

619. Submissions made to me by Users of the DBNGP raised concerns in regard to the nature of force majeure events defined in the Access Contract Terms and Conditions, and in regard to strikes or industrial disputes being excluded from possible consideration as force majeure events.

620. In regard to the definition of force majeure events, I am satisfied that the broad definition of force majeure events, without specification of the actual events that would constitute force majeure events, is common commercial practice. I do not consider definition in this manner to be unreasonable.

621. In regard to Epic Energy's proposed exclusion of strikes and industrial disputes as events of force majeure, I am of the view that strikes and industrial disputes may be events beyond the control of an affected party, as for example where industrial action is taken on an industry-wide scale. I do not consider it reasonable that strikes and industrial action be entirely excluded from consideration as events or circumstances of force majeure.

622. Submissions made to me also indicated concern as to the absence of relief for Users from capacity charges when Epic Energy claims force majeure in respect of an interruption in services. It is my view that it is consistent with creating incentives for efficient and reliable operation of the pipeline that the direct financial cost of claiming force majeure should rest with the claimant, who is generally in the best position to

minimise the risks of the event to which the claim relates, or to remedy the event. I take the view that the current absence of relief for Users from capacity charges when Epic Energy claims force majeure in respect of an interruption in services is not reasonable.

623. Clause 16 of the Access Contract Terms and Conditions contains provisions for the determination and levying of charges on Users for services. Provisions include:

- establishing an obligation for Users to pay charges;
- providing for annual adjustment of charges in accordance with changes in the consumer price index (CPI);
- providing for levying on Users of charges additional to the Reference Tariff for the purpose of recovering costs arising from a change in, or change on the method of imposition of, any supply tax which was applicable and in effect at the date of a contract, and any new supply tax; and
- providing for adjustment of charges in response to a change in the regulatory environment.

624. Sub-clause 16.3 of the Access Contract Terms and Conditions provides for Epic Energy to recover costs arising from a supply tax through charges additional to the Reference Tariff, and for these charges to be adjusted in accordance with any changes in costs incurred by Epic Energy as a result of changes to the supply-tax regime.

625. This clause, and the Access Contract Terms and Conditions generally, were drafted and submitted to me prior to the implementation of the Goods and Services Tax and as a result the final details of this tax were uncertain. As the Goods and Services Tax has subsequently been implemented, sub-clause 16.3 would be in part redundant as the associated tax margin on transmission charges could be incorporated as part of the Reference Tariff.

626. Sub-clause 16.3 would, if maintained in the approved Access Arrangement, still operate for the purpose of allowing changes in costs arising from a change in the Goods and Services Tax Regime to be passed through to Users as a charge or charges levied in addition to the Reference Tariff.

627. While the Code does not prevent the levying of charges as contemplated by sub-clause 16.3 of the Access Contract Terms and Conditions, the Code does not contemplate the imposition of charges separate to the Reference Tariff for Reference Services, where those charges are in the nature of a service provision charge as opposed to a penalty. Rather, the approach is that there be only one charge. In this regard:

- the concept of "Total Revenue" as defined in section 8.2 and applied in section 8.4 contemplates there will only be a single charge for each Reference Service whereby the Service Provider recovers its revenue (being the cost of providing services) from users;
- the single charge for each Reference Service will be one Reference Tariff (under section 3.3);

- under the definitions of "Reference Tariff", "Tariff" (which refers to "the charge") and "Charge" (which refers to "the amount") in section 10.8, the charge that applies is a single amount; and

- sections 8.4, 8.36 and 8.37 specifically allow for the recovery of Non Capital Costs, which appears to me to be the true character of the costs Epic Energy seeks to recover separately to the Reference Tariff.

628. Accordingly, as the Code does not specifically provide for the imposition of charges in the way proposed by Epic Energy (that is, separate to the Reference Tariff), I am of the view that the charges do not fall within section 3.1 to 3.20 of the Code and I am unable to approve them as such.

629. Further, under section 6.13 of the Code, the Arbitrator can only decide to require the Service Provider to provide the Reference Service at the Reference Tariff in a dispute about which tariff should apply to that Reference Service. Section 6.13 effectively means that in any dispute Epic Energy bears the risk that the Arbitrator would not require the Prospective User to pay those charges as they do not form part of the Reference Tariff. If Epic Energy wishes to avoid this risk, it should amend its proposed Access Arrangement to include a tariff variation method as provided for by sections 8.3A – H of the Code so that it can pass on the charges (to which sub-clause 16.3 of the Access Contract Terms and Conditions refers) as part of the Reference Tariff and vary the latter if and when the charges change.

630. Sub-clause 16.4 of the Access Contract Terms and Conditions provides for Epic Energy to apply to the Regulator for an adjustment of charges if there is a change in the regulatory environment that causes Epic Energy to incur additional costs during the Access Arrangement Period.

631. Charges are defined in sub-clause 1.1 of the Access Contract Terms and Conditions as follows.

> "Charges" means the Gas Receipt Charge, Pipeline Capacity Charge, Compression Charge, Compressor Fuel Charge, Delivery Point Charge and any other fee or charge pursuant to the Access Contract.

632. The Access Contract Terms and Conditions make explicit provision for the following charges that are in addition to the charges that make up the Reference Tariff, as defined in clause 8 of the Access Arrangement:

- a range of penalty charges relating to delivery to the DBNGP of out-of-specification gas, failure to make nominations in good faith, overrun, gas imbalances, peaking and failure of a User to comply with an unavailability notice (sub clauses 4.4, 5.2, 6.4, 7.1 and 5.4); and

- amounts payable to Epic Energy in respect of changes to supply taxes (sub-clause 16.3).

633. No explicit provision is made in the Access Contract Terms and Conditions for Epic Energy to levy a charge on Users that is additional to the Reference Tariff, for the purposes of pass-through to Users of costs incurred as a result of regulation.

634. If it is the intent of Epic Energy to pass through the costs of regulation in a Charge that is a component of the Reference Tariff, then the adjustment of charges under sub-clause 16.4 of the Access Contract Terms and Conditions would constitute a change in the Reference Tariff.

635. The Code provides for variation of a Reference Tariff during an Access Arrangement Period only through implementation of an Approved Reference Tariff Variation Method as provided for in sections 8.3B to 8.3H.

636. It is my view that the provisions for the adjustment of charges in sub-clause 16.4 of the Access Contract Terms and Conditions are not sufficient to constitute a Reference Tariff Variation Method as provided for in sections 8.3B to 8.3H. I consider that an adjustment notified to me pursuant to sub-clause 16.4 could only be treated as a revision to the Reference Tariff and dealt with in accordance with sections 2.28 and following of the Code, not as proposed by Epic Energy.

637. Clause 17 of the Access Contract Terms and Conditions defines events of default by the User and makes provision for consequential termination of the relevant Access Contract. Provisions of clause 17 address:

- definition of events of default;
- definition of rights of Epic Energy when an event of default occurs;
- rights of a User to terminate the Access Contract; and
- continuance of rights and obligations after the termination of an Access Contract.

638. Under sub-clause 17.1 of the Access Contract Terms and Conditions, an event of default is deemed to occur in certain circumstances. Clause 17.1(c) provides that an event of default by the User occurs when the User fails to pay any amount due to Epic Energy and that amount, plus any interest, is still outstanding seven days after the date of a notice from Epic Energy.

639. It is not clear in paragraph 17.1(c) whether default arising from a failure to pay any amount that is due to Epic Energy arises seven days after the date of posting of a notice of demand or the date of its receipt by the User. This should be clarified prior to approval of the Access Arrangement.

640. Clause 18 of the Access Contract Terms and Conditions contains provisions relating to dispute resolution and independent experts. No submissions received by me addressed these provisions and I have no reason to consider the provisions to not be reasonable.

641. Clause 19 of the Access Contract Terms and Conditions provides for assignment of an Access Contract by either Epic Energy or the relevant User.

642. A submission made to me indicated that it would be reasonable to expect a prospective Shipper under the proposed Access Arrangement to have identical assignment provisions to those proposed for Epic Energy.

643. Sub-clause 19.2 provides for a User to assign rights by way of a Bare Transfer, by way of trading in the Secondary Market, or with prior written consent of Epic Energy, which consent shall not be unreasonably withheld.

644. The Code deals with assignment by Users only in sections 3.9 to 3.11, in relation to the Trading Policy. Sub-clause 19.2 meets the requirements of the Code by providing for a User to assign rights by way of a Bare Transfer, by way of trading in the Secondary Market, or with prior written consent of Epic Energy, which consent shall not be unreasonably withheld. On the basis that Clause 19 of the Access Contract Terms and Conditions complies with the requirements of the Code, I am of the view that clause 19 is reasonable.

645. Clause 20 of the Access Contract Terms and Conditions contains provisions relating to confidentiality. No submissions received by me addressed these provisions and I have no reason to consider the provisions to not be reasonable.

646. Clause 21 of the Access Contract Terms and Conditions makes provision for representation and warranties provided by the User to Epic Energy and by Epic Energy to the User. This includes provision for Epic Energy to require a User to provide security against its obligations under an Access Contract (sub-clause 21.4).

647. A submission made to me by a User of the DBNGP indicated concern that there is inadequate protection for Users against unreasonable requests from Epic Energy for the provision of security. I have examined the relevant provisions of the Access Contract Terms and Conditions and further submissions made to me by Epic Energy and I consider that Epic Energy's discretion may be adequately constrained by the relevant provisions as proposed.

648. Clauses 22 to 33 of the Access Contract Terms and Conditions contain provisions and declarations in relation to records and information; insurances; no waivers; entire agreement; severability; entry and inspection; ownership, control, maintenance and risk; rebate sharing contract; no common carriage; Epic Energy not a supplier of gas; stamp duty; and no third party benefit. No submissions received by me addressed these provisions and I have no reason to consider the provisions to not be reasonable

Capacity Management Policy

649. Sections 3.7 and 3.8 of the Code require that an Access Arrangement include a Capacity Management Policy:

> 3.7 An Access Arrangement must include a statement (a Capacity Management Policy) that the Covered Pipeline is either:
>
> (a) a Contract Carriage Pipeline; or
>
> (b) a Market Carriage Pipeline.
>
> 3.8 The Relevant Regulator must not accept an Access Arrangement which states that the Covered Pipeline is a Market Carriage Pipeline unless the Relevant Minister of each Scheme Participant in whose Jurisdictional Area the Pipeline is wholly or partly located has given notice to the Relevant Regulator permitting the Covered Pipeline to be a Market Carriage Pipeline.

650. The Code requires no more than a statement in the Access Arrangement that the DBNGP is a Contract Carriage or Market Carriage pipeline, subject to Ministerial approval for any proposal for the pipeline to be a Market Carriage pipeline. As the proposed Access Arrangement states that the DBNGP is to be managed as a Contract Carriage pipeline, I am of the view that the requirements of the Code are met.

Trading Policy

651. Section 3.9 of the Code requires that an Access Arrangement for a Covered Pipeline, which is described in the Access Arrangement as a Contract Carriage Pipeline, must include a policy that explains the rights of a User to trade its right to obtain a service to another person (a Trading Policy).

652. Section 3.10 of the Code requires that the Trading Policy must comply with the following principles.

(a) A User must be permitted to transfer or assign all or part of its Contracted Capacity without the consent of the Service Provider concerned if:

(i) the User's obligations under the contract with the Service Provider remain in full force and effect after the transfer or assignment; and

(ii) the terms of the contract with the Service Provider are not altered as a result of the transfer or assignment (a Bare Transfer).

In these circumstances the Trading Policy may require that the transferee notify the Service Provider prior to utilising the portion of the Contracted Capacity subject to the Bare Transfer and of the nature of the Contracted Capacity subject to the Bare Transfer, but the Trading Policy must not require any other details regarding the transaction to be provided to the Service Provider.

(b) Where commercially and technically reasonable, a User must be permitted to transfer or assign all or part of its Contracted Capacity other than by way of a Bare Transfer with the prior consent of the Service Provider. The Service Provider may withhold its consent only on reasonable commercial or technical grounds and may make its consent subject to conditions only if they are reasonable on commercial and technical grounds. The Trading Policy may specify conditions in advance under which consent will or will not be given and conditions that must be adhered to as a condition of consent being given.

(c) Where commercially and technically reasonable, a User must be permitted to change the Delivery Point or Receipt Point from that specified in any contract for the relevant service with the prior written consent of the Service Provider. The Service Provider may withhold its consent only on reasonable commercial or technical grounds and may make its consent subject to conditions only if they are reasonable on commercial and technical grounds. The Trading Policy may specify conditions in advance under which consent will or will not be given and conditions that must be adhered to as a condition of consent being given.

653. Section 3.11 of the Code states that examples of things that would be reasonable for the purposes of paragraphs 3.10(b) and (c) are:

(a) the Service Provider refusing to agree to a User's request to change its Delivery Point where a reduction in the amount of the service provided to the original Delivery Point will not result in a corresponding increase in the Service Provider's ability to provide that service to the alternative Delivery Point; and

(b) the Service Provider specifying that, as a condition of its agreement to a change in the Delivery Point or Receipt Point, the Service Provider must receive the same amount of revenue it would have received before the change.

654. A Trading Policy is provided by Epic Energy in section 11 of the proposed Access Arrangement. The Trading Policy provides for three mechanisms for trading in pipeline capacity:

- bare transfers in accordance with section 3.10 of the Code;
- conditional transfers in accordance with provisions set out in clause 19.2 of the Access Contract Terms and Conditions to the effect that, subject to a User's rights to trade capacity in the Secondary Market, the User shall not otherwise assign or encumber its right or interest under the Access Contract without obtaining the prior written consent of Epic Energy, which consent shall not be unreasonably withheld; and
- transfers via a Secondary Market administered by Epic Energy.

655. The Secondary Market constitutes a spot market for capacity contracted under a Firm Service contract and traded for periods of one "Day" as defined in the proposed Access Arrangement. Paragraph 11.3(f) of the proposed Access Arrangement indicates that the objective of the Secondary Market is to encourage Firm Service Users to make unutilised capacity available to third parties. Under the proposed Access Arrangement, there will not be an interruptible service or an authorised overrun service available to Users. A User's requirements over and above its contracted capacity will need to be met (subject to availability) from the Secondary Market, but that capacity can be acquired at any time during the relevant Day.

656. The provision of capacity through the Secondary Market comprises a Non-Reference Service under the proposed Access Arrangement, and is provided under the same terms and conditions as set out in the Access Contract Terms and Conditions, except as expressly modified by Secondary Market Rules and Secondary Market Terms and Conditions as amended or varied by Epic Energy from time to time. Secondary Market Rules and Secondary Market Terms and Conditions were submitted to the Regulator with the proposed Access Arrangement documentation, but are not considered to comprise part of the proposed Access Arrangement.[129]

657. Relocation of capacity by a User between Delivery Points is addressed in clause 3.3 of the Access Contract Terms and Conditions and provides for a User to:

- relocate Delivery Point MDQ on a spot basis to a Delivery Point upstream of the contracted Delivery Point without prior consent of Epic Energy;
- relocate Delivery Point MDQ on a spot basis to a Delivery Point downstream of the contracted Delivery Point with prior consent of Epic Energy, which consent shall not be unreasonably withheld other than on operational grounds, and subject to the User acknowledging that the equivalent downstream quantity may be less than the Delivery Point MDQ that the User seeks to relocate.

[129] Under section 3.6 of the Code, an Access Arrangement is only required to include terms and conditions for Reference Services, i.e. services for which a Reference Tariff is specified. The Secondary Market Service does not (and cannot) have a Reference Tariff specified and therefore cannot be a Reference Service, nor can the Regulator require that the Access Arrangement include the terms and conditions for provision of the Secondary Market Service.

658. All relocations of Delivery Point MDQ are subject to the rights of other Users with contracted Delivery Point MDQ at the Delivery Point to which the relocation is desired.

659. Relocations of Receipt Point MDQ are addressed in clause 3.5 of the Access Contract Terms and Conditions. Subject to operational feasibility, a User may supply gas to any Receipt Point in Zone 1 at quantities greater than the User's Access Contract for the Receipt Point, subject to operational feasibility and the aggregate gas quantity for the User across all Receipt Points not exceeding the User's aggregate contracted MDQ across all Receipt Points.

660. Submissions made to me raised concerns with the provisions for relocation of capacity across Receipt Points and Delivery Points, and with the operation of Epic Energy's proposed Secondary Market.

661. In regard to the relocation of capacity across Receipt Points and Delivery Points, submissions to me expressed concern that the ability to relocate capacity is relatively restricted and there is no scope to relocate capacity between Delivery Points on a long term basis.

662. Epic Energy has indicated to me that the Access Arrangement provides for relocation of capacity on a short term (single day) basis through the Secondary Market and that longer term relocation can be negotiated outside of the terms of the Access Arrangement.

663. Under the provisions of paragraph 3.10(c) of the Code, Users must be permitted to change the Receipt Point or Delivery Point from that specified in a contract for a service subject to the prior written consent of the Service Provider, where that consent may only be withheld on reasonable commercial or technical grounds. Accordingly, I take the view that the Access Arrangement does not comply with the requirements of the Code in this respect.

664. Submissions also indicated concern as to the absence of provision in the Access Contract Terms and Conditions for a User to relinquish contracted capacity. I acknowledge that a fixed contracted MDQ in a service agreement for the Firm Service does expose the User to the risk of a decline in service requirements, albeit reducing the risk of the Service Provider. I also note that under the Trading Policy a User has rights to transfer capacity to other Users either on a temporary or permanent basis and thereby limit the risk of financial exposure. I take the view that the fixed MDQ in service agreements with provision to trade capacity constitutes a reasonable balance of risk and interests between Epic Energy and Users.

665. Several submissions on the proposed Access Arrangement indicated concern over the operation of the proposed Secondary Market Service and related Secondary Market Rules and terms and conditions. Matters of concern related to:

- price determination in the Secondary Market;
- the dual role of Epic Energy both operating and participating in the Secondary Market; and

- rights of Users to participate in the Secondary Market.

666. As a general point, in my assessment of the proposed Access Arrangement, the proposed Secondary Market Service and related rules and terms and conditions are not subject to review in the same way that the Access Contract Terms and Conditions are. The reason for this is that the Secondary Market Service is not a Reference Service (nor is it part of the Firm Service). While I have power under section 3.2 of the Code to require descriptive information on Non-Reference Services to be included in the Access Arrangement, there is no obligation on a Service Provider to include terms and conditions for Non-Reference Services in an Access Arrangement. I am thus unable to require any alteration to the Secondary Market Rules and/or the related terms and conditions. Additionally, as capacity traded in the Secondary Market does not have a defined price (the price being the market price), a Reference Tariff cannot be specified and so the Secondary Market Service may not be included in the Access Arrangement as a Reference Service.

667. Notwithstanding this, several submissions made to me indicated that the information provided by Epic Energy in relation to the Secondary Market is not sufficient to describe how the Secondary Market will operate. In particular, the information provided does not make clear:

- whether the Secondary Market Service is a service providing actual pipeline capacity or is a brokerage service for facilitating the exchange of capacity between Shippers or between Epic Energy and Users, or a combination of these;
- the rights of existing Users of the pipeline to trade capacity in the Secondary Market; and
- the interaction of capacity trading in the Secondary Market with spot purchases of capacity by existing Users with contracts entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998*.

668. Section 3.9 of the Code requires that the Trading Policy must explain the rights of a User to trade its right to a service to another person. The provisions for the Secondary Market create such rights and, therefore, these rights should be described in the Trading Policy. I consider that it would be in accordance with the requirements of the Code, and the interests of both Users and Epic Energy, for the Trading Policy to be clarified in this regard.

Queuing Policy

669. Section 3.12 of the Code requires that an Access Arrangement must include a policy for determining the priority that a Prospective User has, as against any other Prospective User, to obtain access to Spare Capacity and Developable Capacity (and to seek dispute resolution under section 6 of the Code) where the provision of the service sought by that Prospective User may impede the ability of the Service Provider to provide a service that is sought or which may be sought by another Prospective User (a Queuing Policy).

670. Section 3.13 of the Code requires that the Queuing Policy must:

(a) set out sufficient detail to enable Users and Prospective Users to understand in advance how the Queuing Policy will operate;

(b) accommodate, to the extent reasonably possible, the legitimate business interests of the Service Provider and of Users and Prospective Users; and

(c) generate, to the extent reasonably possible, economically efficient outcomes.

671. Section 3.14 of the Code provides for the Relevant Regulator to require the Queuing Policy to deal with any other matter the Relevant Regulator thinks fit, taking into account the matters listed in section 2.24 of the Code.

672. Epic Energy has provided a Queuing Policy as clause 5.3 of the proposed Access Arrangement. The Queuing Policy provides generally for Access Requests to have priority determined by the order in which they are received by Epic Energy, subject to several qualifications:

- Epic Energy may deal with Access Requests out of order provided that the Access Requests that were first in time are not ultimately disadvantaged;
- an Access Request may be rejected at any stage prior to its acceptance by Epic Energy, in which case the priority of the Access Request is lost;
- the Queuing Policy is subject to any Capacity Expansion Options which may be granted by Epic Energy from time to time; and
- Capacity Expansion Options will be processed independently of and stand apart from any other Access Requests which have been received, and will receive priority to Prospective Shippers in the queue.[130]

673. In considering the proposed Queuing Policy, I have assessed whether it meets the requirements and objectives set out in section 3.13 of the Code.

674. I have received several submissions indicating that the Queuing Policy does not set out sufficient detail to enable Users and Prospective Users to understand in advance how the Queuing Policy will operate. In particular, submissions have indicated that the Queuing Policy does not provide sufficient information to understand:

- under what conditions and according to what constraints Epic Energy may reject an Access Request, change the priority order of Access Requests in the queue, or grant access to prospective Users other than in order of the queue;
- how the Queuing Policy operates in respect of priority of access to spare capacity in the pipeline in respect of Access Requests for different services;

[130] A Capacity Expansion Option is defined in the Access Arrangement as part of the Extensions/Expansions Policy and comprises an option sold by Epic Energy to a Prospective User providing the Prospective User with a right to a specified quantity of capacity for Firm Service on the terms and conditions specified in the Capacity Expansion Option. A Capacity Expansion Option will have a purchase price to be determined by Epic Energy and is able to be traded by the Prospective User to another Prospective User.

- what is the interaction between the Queuing Policy and Capacity Expansion Options in respect of priority of access to spare capacity in the pipeline; and

- what will happen to the disposition of an Access Request in the queue when that Access request is withdrawn and re-submitted or simply amended.

675. In respect of the ability of Epic Energy to change the priority order of Access Requests in the queue, or grant access to prospective Users other than in order of the queue, the proposed Queuing Policy indicates that Epic Energy may deal with Access Requests out of order provided that the Access Requests that were first in time are not ultimately disadvantaged, but "ultimately disadvantaged" is not defined and explained. The Queuing Policy does not address the other matters listed above in respect of which submissions made to me have indicated that insufficient information is provided to understand how the Queuing Policy will operate.

676. After consideration of the submissions made to me, I am of the view that the Queuing Policy does not provide sufficient detail to enable Users and Prospective Users to understand in advance how the Queuing Policy will operate, and as a consequence the Queuing Policy does not comply with the requirements of section 3.13(a) of the Code.

677. A related matter that I considered in my Draft Decision is whether the Queuing Policy should describe how priority to capacity is determined amongst persons exercising Capacity Expansion Options. After receiving further information from Epic Energy on this matter, I am satisfied that the establishment of priority amongst persons exercising Capacity Expansion Options is not a relevant issue to the Queuing Policy: a Capacity Expansion Option comprises an option for a Prospective User to require that Epic Energy provide capacity. Epic Energy has indicated to me that the exercise of a Capacity Expansion Option requires Epic Energy to provide capacity in accordance with the terms of the option, independently of any obligations of Epic Energy arising from the exercise of a Capacity Expansion Option by any other Prospective User.

678. In addition to considering the level of detail of the proposed Queuing Policy, I have also assessed the extent to which the Queuing Policy meets the requirements of sections 3.13(b) and 3.13(c) of the Code in respect of whether the Queuing Policy accommodates, to the extent reasonably possible, the legitimate business interests of the Service Provider and of Users and Prospective Users, and whether it would generate, to the extent reasonably possible, economically efficient outcomes. In this regard and in response to submissions made to me, I have given consideration to:

- the absence of provision in the Queuing Policy for notification of Prospective Users with queued Access Requests of the status of those Access Requests in the queue; and

- the question of whether the Queuing Policy should provide for a Service Agreement for a Reference Service to be capable of including an option to extend the term of the Service Agreement for the capacity contracted for under that agreement, without being subject to reallocation on the basis of the Queuing Policy.

679. In relation to my consideration of both of these issues, section 3.14 of the Code provides for me to require the Queuing Policy to deal with any other matter that I think fit taking into account the matters listed in section 2.24 of the Code.

680. In regard to the first of these issues listed in paragraph 678, I have taken into account that substantial investment decisions of Prospective Users and of prospective end-users of gas may be affected by knowledge of the likely timing for satisfaction of an Access Request. I therefore consider it to be consistent with the reasonable interests of Users and Prospective Users, and not contrary to the legitimate business interests of Epic Energy, for Prospective Users with an Access Request in a queue to be provided with information on the position of the Access Request in the queue and of the expected timing of satisfaction of the Access Request. I am therefore of the view that the Queuing Policy should oblige Epic Energy to provide such information.

681. The issue of whether existing Users should have a priority of access to capacity as is necessary to extend existing Access Agreements subsequent to their expiry was a matter that I addressed in my Draft Decision. I formed the view that a Service Agreement for a Reference Service should be capable of including an option to extend the term of the Service Agreement for the capacity contracted for under that agreement, without being subject to reallocation on the basis of the Queuing Policy.

682. In response to submissions made to me by Epic Energy subsequent to the Draft Decision, I have given further consideration to this matter. In particular, I have given consideration to the potential impact on a Service Provider of a broad requirement for an Access Agreement to provide for an option to maintain access to capacity beyond the term of the existing Access Agreement. I am of the view that provision in an Access Agreement for such an option may be contrary to the Service Provider's legitimate business interests unless the terms of such an option are such as to protect these interests. Moreover, I consider that terms of such an option that would balance the interests of the User and Service Provider would depend on other elements of an Access Agreement, such as the term of that agreement.

683. Taking into account these considerations I am of the view that, at least in the first instance, the provision in an Access Agreement of an option to extend the agreement should be a matter for negotiation between the Prospective User and Epic Energy.

Extensions/Expansions Policy

684. Section 3.16 of the Code requires that an Access Arrangement include a policy (an Extensions/Expansions Policy) which sets out:

(a) the method to be applied to determine whether any extension to, or expansion of the Capacity of, the Covered Pipeline:

(i) should be treated as part of the Covered Pipeline for all purposes under the Code; or

(ii) should not be treated as part of the Covered Pipeline for any purpose under the Code;

(for example, the Extensions/Expansions Policy could provide that the Service Provider may, with the Relevant Regulator's consent, elect at some point in time whether or not an extension or expansion will be part of the Covered Pipeline or will not be part of the Covered Pipeline);

(b) how any extension or expansion, which is to be treated as part of the Covered Pipeline, will affect Reference Tariffs (for example, the Extensions/Expansions Policy could provide:

(i) Reference Tariffs will remain unchanged but a Surcharge may be levied on Incremental Users where permitted by sections 8.25 and 8.26 of the Code; or

(ii) specify that a review will be triggered and that the Service Provider must submit revisions to the Access Arrangement pursuant to section 2.28 of the Code);

(c) if the Service Provider agrees to fund New Facilities if certain conditions are met, a description of those New Facilities and the conditions on which the Service Provider will fund the New Facilities.

685. Section 3.16 further provides that the Regulator may not require the Extensions/Expansions Policy to state that the Service Provider will fund New Facilities, unless the Service Provider agrees.

686. Epic Energy has provided an Extensions/Expansion Policy in clause 12 of the proposed Access Arrangement. Elements of the policy are as follows.

- Epic Energy will enhance or expand the capacity of the DBNGP where it considers the requirements of section 6.22 of the Code (relating to a requirement by the Arbitrator to expand the pipeline) are satisfied. It will otherwise enhance or expand capacity as it sees fit.

- Epic Energy may from time to time offer Capacity Expansion Options, which are for Firm Service capacity on the DBNGP. A Capacity Expansion Option gives a Prospective User a right to a specified quantity of capacity on particular terms and conditions. Capacity Expansion Options will have a purchase price determined by Epic Energy and are capable of being traded with other Prospective Users.

- Any extension or expansion to the pipeline will become part of the Covered Pipeline unless Epic Energy elects otherwise. In the case of Extensions or Expansions undertaken other than as a result of exercise of a Capacity Expansion Options, Epic Energy will provide notice to the Regulator of the extension or expansion that Epic Energy elects will not become part of the Covered Pipeline.

- Expansions or extensions of the DBNGP that become part of the Covered Pipeline will not affect Reference Tariffs before the next Revisions Commencement Date (i.e. within the Access Arrangement Period).

- Epic Energy may from time to time seek surcharges or capital contributions in respect of New Facilities Investment. Where it does not do so, a User using incremental capacity will pay the Reference Tariff.

687. In consideration of Epic Energy's proposed Extensions/Expansions Policy, I addressed three matters raised in submissions made to me:

- the operation of Epic Energy's proposed Capacity Expansion Options;

- the impacts of extensions and expansions on the Reference Tariff, the circumstances in which Epic Energy will require Capital Contributions from Prospective Users in relation to extensions or expansions of the pipeline, and the circumstances in which Epic Energy will levy capital Surcharges on Users of Incremental Capacity; and

- the inclusion of extensions or expansions as part of the Covered Pipeline.

688. As noted above, Epic Energy has proposed to offer a facility of Capacity Expansion Options, which comprise assignable options to require Epic Energy to provide a specified quantity of capacity on particular terms and conditions (as specified for a particular option), and with the option itself having a purchase price determined by Epic Energy, and being capable of being traded.

689. Submissions made to me and my own consideration of Epic Energy's proposed Extensions and Expansions Policy indicate that it is unclear from the information provided in the policy whether the price of a Capacity Expansion Option includes an amount relating to a capital contribution or whether the price is simply a price for the facility represented by the option.

690. I have given consideration to whether the Access Arrangement should provide further information in this respect. Epic Energy's proposal for Capacity Expansions Options is a matter that is outside of the requirements of the Code in respect of an Extensions/Expansions Policy. While I consider that Users and Prospective Users of the DBNGP may welcome provision in the Access Arrangement of further information on the operation of Capacity Expansion Options, I do not consider that it is a matter on which I can require amendment of the Access Arrangement.

691. In regard to Capital Contributions and Surcharges, the proposed Extensions/Expansions Policy indicates that Epic Energy may from time to time seek Surcharges or Capital Contributions from Prospective Users in respect of New Facilities Investment. However, the policy gives no information on the circumstances in which this may occur. This may create confusion amongst readers of the Access Arrangement and supporting documents due to assertions elsewhere by Epic Energy that all Users, including new Users, would pay the same Tariff for the Reference Service.

692. There is no inconsistency between the proposed Extensions/Expansions Policy and other material put forward by Epic Energy – inasmuch as Capital Contributions and Surcharges are charges that are in addition to a Reference Tariff – and that the Code itself provides guidance as to the circumstances in which Capital Contributions may be sought and Surcharges levied. However, taking into account the factors of section 2.24 of the Code, I consider that it would be consistent with the reasonable interests of Prospective Users if the Access Arrangement were to include further information on the circumstances in which Capital Contributions may be sought and Surcharges levied, and declaratory statements that Capital Contributions and Surcharges will occur in accordance with the provisions of the Code.

693. In regard to the inclusion of extensions or expansions of the DBNGP as part of the Covered Pipeline, the proposed Extensions/Expansions Policy provides for Epic Energy to exercise discretion as to whether an extension or expansion of the DBNGP becomes part of the Covered Pipeline for the purposes of application of the Code. I also note that the policy provides for Epic Energy to advise the Regulator of a decision to include an extension or expansion of the DBNGP as part of the Covered Pipeline where that extension or expansion arises other than as a result of exercise of a Capacity Expansion Option, but not where the extension or expansion is as a result of the exercise of a Capacity Expansion Option.

694. In situations where a Service Provider elects not to include an extension or expansion of a Covered Pipeline as part of the Covered Pipeline, there is still a process under section 1 of the Code for coverage of the extension or expansion to occur. This is not a determination made by the Relevant Regulator under the Code for that pipeline, but rather one made by the Relevant Minister upon receipt of a recommendation from the National Competition Council. The only possible role of the Relevant Regulator in these circumstances is for the Regulator to make an application to the National Competition Council requesting that the extension or expansion be part of the Covered Pipeline.

695. I am, however, of the view that the Extensions/Expansions Policy should make provision for the Regulator to be advised of a decision by Epic Energy to not include an extension or expansion of the DBNGP as part of the Covered Pipeline, a provision that currently does not exist for an extension or expansion arising as a result of the exercise of a Capacity Expansion Option.

Review and Expiry of the Access Arrangement

696. Section 3.17 of the Code requires that an Access Arrangement include:

(a) a date upon which the Service Provider must submit revisions to the Access Arrangement (a Revisions Submission Date); and

(b) a date upon which the next revisions to the Access Arrangement are intended to commence (a Revisions Commencement Date).

697. In approving the Revisions Submissions Date and Revisions Commencement Date, the Regulator must have regard to the objectives for Reference Tariffs and Reference Tariff Policy in section 8.1 of the Code. In making a decision on an Access Arrangement (or revisions to an Access Arrangement) and if considered necessary having had regard to the objectives in section 8.1 of the Code, the Regulator may, under section 3.17 of the Code:

(i) require an earlier or later Revisions Submission Date and Revisions Commencement Date than proposed by the Service Provider in its proposed Access Arrangement;

(ii) require that specific major events be defined that trigger an obligation on the Service Provider to submit revisions prior to the Revisions Submission Date.

698. Section 3.18 of the Code provides for an Access Arrangement Period to be of any length; however, if the Access Arrangement Period is more than five years, the Regulator must not approve the Access Arrangement without considering whether mechanisms should be included to address the risk of forecasts on which the terms of the Access Arrangement were based and approved proving to be incorrect. These mechanisms may include:

(a) requiring the Service Provider to submit revisions to the Access Arrangement prior to the Revisions Submission Date if certain events occur, for example:

   (i) if a Service Provider's profits derived from a Covered Pipeline are outside a specified range or if the value of Services reserved in contracts with Users are outside a specified range;

   (ii) if the type or mix of Services provided by means of a Covered Pipeline changes in a certain way; or

(b) a Service Provider returning some or all revenue or profits in excess of a certain amount to Users, whether in the form of lower charges or some other form.

699. Where a mechanism is included in an Access Arrangement pursuant to section 3.18(a) of the Code, the Regulator must investigate no less frequently than once every five years whether a review event identified in the mechanism has occurred.

700. Section 13 of the proposed Access Arrangement specifies the date on which Epic Energy will submit revisions to the Regulator and the date Epic Energy intends those revisions to commence.

- Epic Energy proposes that the Revisions Submission Date is 1 July 2004.

- Epic Energy proposes that the Revisions Commencement Date is 1 January 2005.

701. The Access Arrangement Period proposed by Epic Energy extends only to the end of next year. The Revisions Commencement Date, which marks the end of the current Access Arrangement Period and the beginning of the next, is a matter for determination by Epic Energy. At the date of this Final Decision, I have not received any indication from Epic Energy of intent to change the Revisions Commencement Date from that indicated in the proposed Access Arrangement.

702. In regard to the Revisions Submission Date and Revisions Commencement Date, Epic Energy has proposed a Revisions Submission Date that is six months prior to the proposed Revisions Commencement Date. While regulatory experience elsewhere throughout Australia indicates that consideration and approval of revisions to an Access Arrangement may be able to be completed in six months, achievement of such a timetable may be contingent on a substantial amount of preliminary investigation and consultation on relevant issues being undertaken prior to the Revisions Submission Date. Given uncertainty as to whether this may be possible for the DBNGP, I consider that it would be prudent for the Access Arrangement to provide for a nine-month period for assessment of proposed revisions, and hence for the Revisions Submission Date to be nine months prior to the Revisions Commencement Date.

703. Several submissions have been made to me proposing that the Access Arrangement should include appropriate triggers for review, and indicating that it may be appropriate for a review to be triggered by changes in taxation arrangements, completion of significant expansions, and the advent of new gas sources outside of Zone 1 of the pipeline. In my Draft Decision I gave consideration to trigger events and indicated that the Access Arrangement should include trigger events relating to changes in taxation or regulation that give rise to substantial cost savings to Epic Energy.

704. My consideration of trigger events in coming to the Draft Decision were, in large part, a reflection of changes in taxation regimes at that time (introduction of the goods and services tax and reductions in the rate of corporate income tax). At the current time I am not aware of any consideration being given by the Commonwealth Government to changes in the taxation system that may have direct and substantial implications for Epic Energy in relation to operation of the DBNGP.

705. I also note that in the absence of any application by Epic Energy to change the Revisions Submission Date and Revisions Commencement Date of the proposed Access Arrangement, revisions must be submitted in 2004. The short period before submissions are due makes consideration of trigger events largely redundant.

706. I am therefore of the view that there is no reason to require that the Access Arrangement include the specification of events that would trigger a requirement for Epic Energy to submit revisions.

Other Matters Addressed by the Proposed Access Arrangement

707. In my Draft Decision, I responded to submissions made to me in respect of three elements of the proposed Access Arrangement that fall outside of the required elements of an Access Arrangement as set out in sections 3.1 to 3.20 of the Code:

- provision under clause 5.2 of the Access Arrangement for Epic Energy to request such further detail and information from a Prospective Shipper as Epic reasonably considers necessary to assess an Access Request;
- the absence of explicit provision in the Access Arrangement for a Prospective User to make a conditional access request, to allow the request to be subject to some condition, such as the Prospective User be successful in securing rights to proceed with a project; and
- a fee proposed by Epic Energy that is payable on submission of an Access Request.

708. In regard to the first of these matters, I indicated in my Draft Decision that Epic Energy should amend the relevant clause of the Access Arrangement to provide greater protection to Prospective Users against unreasonable requests for information.

709. The relevant paragraph 5.2(b) of the proposed Access Arrangement states that:

> In addition to the matters set out in the Access Guide, Epic Energy may request such further detail and information from a Prospective Shipper as Epic Energy reasonably considers necessary to assess the Prospective Shipper's Access Request.

710. I have given further attention to the relevant clauses of the Access Arrangement to determine whether the clause, as proposed offers sufficient protection to Prospective Users. On review, I consider that the clause as it stands (including the words "as Epic Energy reasonably considers necessary") provides adequate protection.

711. In regard to the absence of explicit provision in the Access Arrangement for a Prospective User to make a conditional Access Request, I took the view in my Draft Decision that such provision should be made, noting that it has been possible for Prospective Users to request a conditional access contract under clause 43 of the current Access Manual.

712. Epic Energy subsequently made a submission to me indicating that the proposed Access Arrangement already makes provision for the required flexibility in making Access Requests through provisions for Capacity Expansion Options, provisions for including "conditions precedent" in an Access Contract, and through provisions for

agreement with a project proponent for an Access Contract to be developed "at project level" with a view to it later being transferred to the proponent's designated shipper.

713. In view of the submission from Epic Energy, I accept that the Access Arrangement adequately provides for conditional Access Contracts.

714. Paragraph 5.1(c) of the proposed Access Arrangement requires that a Prescribed Fee of $5,000 accompany an Access Request for a service.

715. In my Draft Decision I gave consideration to whether the Prescribed Fee is a reasonable practice on the part of Epic Energy, taking into account whether the fee may be justified on the basis of cost recovery, and common practice amongst other Australian Service Providers in respect of such a charge. I took the view that the proposed Prescribed Fee of $5,000 is in excess of a reasonable allowance for costs that would be incurred in considering and processing an Access Request in the normal course of events and in the absence of any specific investigations needed to be undertaken to determine whether a service could be provided in accordance with the Access Request. Further, I observed that the levying of a fee such as the Prescribed Fee is not common industry practice in the gas transmission industry.[131] I accepted that some costs are incurred in the normal course of assessment of access requests, but considered that an application fee should not exceed $1,000.

716. I also noted in my Draft Decision that a fee accompanying an Access Request may be unreasonable for services such as the Secondary Market Service or other spot services that Epic Energy may provide. I took the view that the Access Arrangement should describe the nature of contractual arrangements under which a User might utilise the Secondary Market Service or other spot services and how the Prescribed Fee will apply to a request to enter into such an arrangement.

717. Epic Energy has subsequently provided me with information on its expected costs of processing an Access Request, indicating an expected cost of between $3,200 and $6,900 for an Access Request that is ultimately accepted, although noting that most of these costs relate to staff time which is included in the forecast Non Capital Costs of the proposed Access Arrangement.

718. Epic Energy has also made a submission to me indicating that the matter of a fee for an Access Request falls outside of matters addressed by the Code in respect of an Access Arrangement, and hence the Code does not support the requirement for amendment of the proposed Access Arrangement as indicated in my Draft Decision.

719. On the basis of the information provided to me by Epic Energy it is apparent that the fee for an Access Request as proposed by Epic Energy would result in Epic Energy

[131] No provision is made for levying of a fee such as the Prescribed Fee in Access Arrangements or proposed Access Arrangements for the Mildura Pipeline (Envestra Limited), Riverland Pipeline (Envestra Limited), Moomba to Sydney Pipeline (East Australian Pipeline Limited), Amadeus Basin to Darwin Pipeline (N.T. Gas Pty Ltd), Central West Pipeline (AGL Pipelines (NSW) Pty Ltd), Queensland Gas Pipeline (Duke Australia Operations Pty Ltd). An application fee of $5,000 was provided for under the proposed Access Arrangement for the Moomba to Adelaide Pipeline System (Epic Energy) but was required to be modified by the ACCC in its draft decision to be limited in its application. The Western Australian Independent Gas Pipelines Access Regulator approved application fees of $1,000 for the Tubridgi Pipeline and Parmelia Pipeline.

over-recovering some Non Capital Costs as the costs intended to be recovered by the fee have already been included in forecasts of Non Capital Costs taken into account in determining the Reference Tariff. However, as noted by Epic Energy provision for the fee does not fall within the terms and conditions for provision of the Reference Service, or within any other matter dealt with by sections 3.1 to 3.20 of the Code in relation to the required content of an Access Arrangement. It is my view, however, that if Epic wishes to charge the proposed fee for an Access Request, the expected value of the revenue from this fee should be excluded from the forecast of Non Capital Costs to avoid over-recovery of Costs.

720. In regard to the possible application of the fee for an Access Request in respect of the Secondary Market Service, or other spot services that Epic Energy may provide, Epic Energy has made a submission to me indicating that this matter is dealt with in its proposed Secondary Market Rules and Access Guide, indicating that no Prescribed Fee is payable in respect of participation in the Secondary Market, although such a fee is payable by a Prospective User under the proposed Access Arrangement upon lodging an Access Request.

AMENDMENTS

721. Under section 2.16 of the Code I am required, when issuing a Final Decision that does not approve a proposed Access Arrangement, to state amendments that would have to be made to the Access Arrangement in order for me to approve it. Set out below are the amendments that would have to be made to Epic Energy's proposed Access Arrangement in order for me to approve it.

Services Policy

722. Paragraph 6.1(b) of the proposed Access Arrangement should be amended to indicate that Epic Energy will, subject to operational availability, make available to Users the services currently listed in that paragraph as Non-Reference Services (**Amendment 1**).

723. In addition to the Firm Service proposed by Epic Energy, the proposed Access Arrangement should include a Reference Service with the characteristics of the Firm Service but allowing for:

- receipt of gas into the DBNGP at any location on the DBNGP;
- a minimum contract term of no greater than two years; and
- the timely provision to Users of such metering information as is available to Epic Energy and which is necessary to enable Users to assess their potential liability for penalty charges and enable Users to take actions to avoid those charges.

I envisage that the Reference Tariff for this service will be the same as for the Firm Service (**Amendment 2**).

Reference Tariff and Reference Tariff Policy

724. The Reference Tariff for the Firm Service should be revised to reflect the following parameters (**Amendment 3**).

- An Initial Capital Base of $1,550 million as at 31 December 1999, including the value of capital costs associated with the Stage 3A enhancement of the DBNGP;

- Forecast costs of New Facilities Investment as follows (31 December 1999 $million).

Year ending 31 December	2000	2001	2002	2003	2004	Total
Pipeline	0.43	0.28	0.16	0.36	0.16	1.38
Compression	0.96	4.35	4.45	1.83	1.85	13.44
Metering	0.00	0.05	0.05	0.05	0.05	0.20
Other	5.06	5.04	5.72	4.72	0.52	21.06
Total	6.45	9.62	10.28	6.86	2.48	35.69

- A real pre-tax Rate of Return of 7.4 percent.

- Forecast Non Capital Costs as follows (31 December 1999 $million).

Year ending 31 December	2000	2001	2002	2003	2004	Total
Total Non Capital Costs	38.41	39.58	41.83	42.09	41.65	203.56

- A Depreciation Schedule that accords with the relevant principles of section 8 of the Code and that is consistent with depreciation of assets over lives of 70 years for pipelines, 30 years for compression assets, 50 years for metering assets and 30 years for other depreciable assets.

- A present value of Total Revenue (with a discount rate equal to real pre-tax Rate of Return of 7.4 percent) of $768.53 million in dollar values at 31 December 1999.

725. If Epic wishes to charge a fee for submission of an Access Request, the expected value of the revenue from these fees should be excluded from the forecast of Non-Capital Costs (**Amendment 4**).

726. The following requirements for amendment of the proposed Access Arrangement should also be addressed in revising the proposed Reference Tariff for the Firm Service.

- The proposed Access Arrangement should be amended such that the Reference Tariff reflects a location of the Eradu Road Delivery Point in Zone 6 of the pipeline (**Amendment 5**).

- The proposed Access Arrangement should be amended such that compression charges are determined and levied on Users on a strictly "pass through" basis such that Users only pay compression charges associated with compressor stations located on the pipeline between the gas Receipt Point(s) and gas Delivery Point(s) for each gas transmission contract (**Amendment 6**).

- The proposed Access Arrangement should be amended such that compressor fuel charges do not comprise part of the Reference Tariff for the back haul of gas (**Amendment 7**).

- While changes in cost allocations and tariffs may be made over time, the cost allocation and tariff structure proposed for the Firm Service for the Access Arrangement Period should be amended to ensure that for Users or Prospective Users with Delivery Points in any zone of the DBNGP, there is no immediate large increase in the total gas transmission charges under the Reference Tariff relative to the total charge that Users or Prospective Users would have paid under a contract for the T1 Service entered into under the *Gas Transmission Regulations 1994 or Dampier to Bunbury Pipeline Regulations 1998* (**Amendment 8**).

- The proposed Access Arrangement should be amended to include a mechanism to ensure that Epic Energy does not retain revenues from Delivery Point Charges in circumstances where those revenues recover capital costs attributed to capital assets that were financed by Users (**Amendment 9**).

- The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to describe how Delivery Point Charges will be determined for Users where those Users share Delivery Point facilities and where Users take delivery of gas from Notional Delivery Points (**Amendment 10**).

- Paragraph 9.2(b) of the proposed Access Arrangement should be revised so as to re-specify the apportioning of rebatable revenue consistent with providing for Epic Energy to recover reasonable incremental costs incurred in providing Rebatable Services and providing a reasonable incentive to supply these services, but without reference to the Deferred Depreciation Account (**Amendment 11**).

- Clause 9.2 of the proposed Access Arrangement should be amended such that the Threshold Revenue is the amount by which actual revenue from the sale of the Firm Service, and other services in the nature of the Firm Service, falls short of that component of Total Revenue attributable to the provision of Firm Service, plus the cost of providing those services from which Rebatable Revenue was obtained (**Amendment 12**).

- The Reference Tariff should be revised to make provision for distanced-based (i.e. zonal) charging for gas transmission in respect of gas received into the pipeline at points in pipeline zones other than Zone 1 (**Amendment 13**).

Terms and Conditions

727. Provisions under sub-clauses 10.3 and 10.4 of the proposed Access Arrangement for Epic Energy to vary certain terms and conditions without consent of the Regulator are not compliant with the Code. The proposed Access Arrangement should be amended to remove the ability of Epic Energy to change the Access Contract Terms and Conditions without revision of the Access Arrangement in accordance with part 2 of the Code (**Amendment 14**).

728. The Access Contract Terms and Conditions should be amended to contain a provision that expressly states that Epic Energy is under an obligation to accept and deliver gas (**Amendment 15**).

729. Sub-clause 3.6 of the Access Contract Terms and Conditions should be amended to provide for agreement between the Shipper and any other Shipper as to the proportion of gas supplied to a shared Receipt Point and for proportional allocation by Epic Energy of gas supplied to that Receipt Point in the absence of any agreement or due notification, consistent with provisions relating to Delivery Points as set out in sub-clause 3.7 of the Access Contract Terms and Conditions (**Amendment 16**).

730. The proposed Access Arrangement should be amended to provide for maximum rates of the Out of Specification Gas Charge, Nomination Surcharge, Excess Imbalance Charge and Peaking Surcharge to be 350 percent of the relevant 100 percent load factor Reference Tariff (**Amendment 17**).

731. Paragraph 5.3(b) of the Access Contract Terms and Conditions should be amended such that the offending Shipper's liability is not unlimited, but rather Epic Energy and other Shippers should be obliged to take all reasonable steps possible to mitigate any losses occurring in the event of a Shipper taking gas in excess of their contracted capacity, i.e. an Overrun (**Amendment 18**).

732. Clause 6 of the Access Contract Terms and Conditions should be amended such that a User is not liable for an Excess Imbalance Charge in respect of any imbalance arising from an action of Epic Energy (**Amendment 19**).

733. The proposed Access Arrangement should be amended to provide for Users to trade imbalances and thereby reduce potential liabilities to the Excess Imbalance Charge (**Amendment 20**).

734. Sub-clause 1.1 of the Access Contract Terms and Conditions should be amended to define the Imbalance Limit as eight percent of the Shipper's MDQ (**Amendment 21**).

735. Clause 7 of the Access Contract Terms and Conditions should be amended to provide for a User's liability for the Peaking Surcharge to be assessed on the basis of that User's Maximum Hourly Quantity and hourly delivery of gas in aggregate across all of that User's Delivery Points in a pipeline zone for Delivery Points in Zones 1 to 9, and on each lateral pipeline in Zone 10 (**Amendment 22**).

736. Sub-clause 11.5 of the Access Contract Terms and Conditions, relating to interconnection of multiple transmission systems with a distribution network, should be amended to provide that Shippers will be notified of any arrangements between Epic Energy, the other gas transmission system and the operator of that distribution network prior to the time the Shipper becomes subject to any contractual obligation that may be affected by those arrangements (**Amendment 23**).

737. Sub-clause 12.6 of the Access Contract Terms and Conditions, relating to correction of meter readings in instances of metering inaccuracy, should be amended to remove the limitation on the Correction Period (being that the Correction Period will not extend beyond one half of the time elapsed since the date of the Previous

Verification), except in circumstances where the period of inaccuracy cannot be known or agreed upon between Epic Energy and the Shipper (**Amendment 24**).

738. Clause 14 of the Access Contract Terms and Conditions should be amended to provide for Shippers to be given not less than 30 days prior notice of all planned maintenance activity to be carried out on or in relation to the DBNGP which may reasonably be considered likely to interrupt normal gas transmission (**Amendment 25**).

739. The proposed Access Arrangement documents should be amended to include a definition of the term "Receipt Charge" or, alternatively, the term "Gas Receipt Charge" be used instead if that term, as defined in the Access Contract Terms and Conditions, was intended to be used (**Amendment 26**).

740. The definition of "force majeure" in sub-clause 1.1 of the Access Contract Terms and Conditions should be amended such that "strikes or industrial disputes" is not excluded from the scope of events or circumstances of force majeure, at least to the extent that the strikes or industrial disputes are not within the control of the party claiming force majeure or which that party is not able to prevent or overcome (**Amendment 27**).

741. Paragraph 15(d) of the Access Contract Terms and Conditions should be amended to state that Epic Energy will waive charges that are based on capacity reservation (MDQ) where it claims the benefit of force majeure under clause 15, and to the extent that it fails to provide the service that is the subject of the Access Contract (**Amendment 28**).

742. Sub-clause 16.4 of the Access Contract Terms and Conditions, relating to adjustment of charges if there is a change in the regulatory environment should be deleted from the Access Contract Terms and Conditions or amended to clarify that any application will be submitted as a revision to the Access Arrangement in accordance with section 2.28 of the Code (**Amendment 29**).

743. Paragraph 17.1(c) of the Access Contract Terms and Conditions should be amended to clarify whether default arising from a failure to pay any amount that is due to Epic Energy arises seven days after the date of posting of a notice of demand or the date of its receipt by the Shipper (**Amendment 30**).

744. The proposed Access Arrangement and Access Contract Terms and Conditions should be amended to provide for revenue from the Out of Specification Gas Charge, Nomination Surcharge, Overrun Charge, Excess Imbalance Charge, Peaking Surcharge and Unavailability Charge to be rebatable as if the activities or events to which the charges relate were Rebatable Services within the meaning of the Code. The mechanism for rebate of revenue should provide for rebate of a minimum of 95 percent of revenue from these charges to Users of the Firm Service, without any provision for a threshold revenue to be achieved prior to any rebate being paid (A**mendment 31**).

Trading Policy

745. Sub-clause 3.3 of the Access Contract Terms and Conditions should be amended to enable Shippers to relocate capacity across Receipt Points and Delivery Points upstream and downstream of the relevant contracted Receipt or Delivery Point, and on a short term or long term basis, where technically and commercially feasible and with the prior written consent of Epic Energy, that may only be withheld or made conditional on reasonable technical or commercial grounds (**Amendment 32**).

746. Sub-clause 11.2 of the proposed Access Arrangement should be amended to provide for Users of services to change the Receipt Point or Delivery Point for a service from that specified in any contract for that service, subject to the User providing notice to the Service Provider and subject to the Service Provider being able to withhold consent to the change in Receipt Point or Delivery Point on reasonable commercial or technical grounds, in accordance with the requirements set out in section 3.10(c) of the Code (**Amendment 33**).

747. The Access Arrangement should be amended to include a description of the Secondary Market Service, sufficient to describe the rights of Users to trade capacity (**Amendment 34**).

Queuing Policy

748. Clause 5.3 of the proposed Access Arrangement should be amended to describe the circumstances in which Epic Energy may change the priority order of Access Requests in the queue, or grant access to Prospective Users other than in order of the queue (**Amendment 35**).

749. Clause 5.3 of the proposed Access Arrangement should be amended to state the circumstances in which an Access Request may be rejected (**Amendment 36**).

750. Clause 5.3 of the proposed Access Arrangement should be amended to provide for the establishment and operation, in accordance with the provisions of clause 5.3 (as amended), of separate queues for Access Requests to the extent the different services described in the proposed Access Arrangement are independent in their use of pipeline capacity (**Amendment 37**).

751. Clause 5.3 and/or clause 12.3 of the proposed Access Arrangement should be amended to state that a Capacity Expansion Option is only capable of being exercised to secure existing spare capacity of the pipeline where there is no Access Request in a queue that could otherwise be satisfied by that Spare Capacity (**Amendment 38**).

752. Clause 5.3 of the proposed Access Arrangement should be amended to describe the effect on the position in the queue of withdrawing an Access Request and re-submitting it, or amending an Access Request (**Amendment 39**).

753. Clause 5.3 of the proposed Access Arrangement should be amended to provide for Prospective Users to be notified at the time an Access Request is made of the time when that Access Request may be met, including details of the position in the queue of that Access Request, but subject to Epic Energy complying with any confidentiality obligations to other Prospective Users (**Amendment 40**).

754. Clause 5.3 of the proposed Access Arrangement should be amended to provide for a Prospective User to be notified of any material change (in the context of the relevant Prospective User's application) in the expected timing of when the Prospective User's Access Request in the queue will be satisfied (**Amendment 41**).

Extensions/Expansions Policy

755. The Access Arrangement should be amended to describe the circumstances in which capital contributions will be sought under clause 12.7 of the proposed Access Arrangement (**Amendment 42**).

756. The proposed Access Arrangement should be amended to include a description of the circumstances in which surcharges are likely to be sought under clause 12.7 of the proposed Access Arrangement (**Amendment 43**).

757. Clause 12.7 of the proposed Access Arrangement should be amended to state that Epic Energy will only seek and will recognise (for the purpose of determining rebates) surcharges and capital contributions in accordance with the Code (**Amendment 44**).

758. Clause 12.7 of the proposed Access Arrangement, relating to the imposition of surcharges, should be amended to be subject to Epic Energy providing written notice to the Regulator of any intention to impose surcharges (**Amendment 45**).

759. The Extensions/Expansions Policy of the proposed Access Arrangement should be amended to make provision for Epic Energy to advise the Regulator of a decision by Epic Energy to not include an extension or expansion of the DBNGP as part of the Covered Pipeline (**Amendment 46**).

Review and Expiry of the Access Arrangement

760. The Access Arrangement should be amended to provide for a Revisions Submission Date on or before 1 April 2004 (**Amendment 47**).

APPPENDIX 1

Value of Franking Credits

Epic Energy has contested the consideration given in the Draft Decision to treatment of franking credits in determination of the Rate of Return:[132]

> Epic Energy proposed that the value of franking credits available to shareholders under the dividend imputation provisions of the Australian taxation system be recognized through use of a value of GAMMA of 44% in its derivation of the rate of return. The parameter GAMMA measures the ratio of utilized franking credits to corporate tax paid on income paid out of dividends.
>
> At the time Epic Energy submitted its proposed Access Arrangement to the Regulator (December 1999), allowance for dividend imputation in the derivation of the rate of return was still relatively new and somewhat contentious. No allowance had been made for it in the tariff analysis undertaken by Price Waterhouse, for the Government of Western Australia, in August 1997, and later made available, in the sale data room, to bidders for the Pipeline. Epic Energy's expert advisor on rate of return, The Brattle Group, sought to estimate GAMMA as the product of a franking credit utilization factor (the proportion of franking credits that are redeemed) and a franking ratio (the ratio of franked dividends to total dividends). Values for the franking credit utilization factor, and for the franking ratio, were obtained from a number of studies by Australian finance academics. These studies indicated a utilization factor of 55%, and a franking ratio of 80%. Accordingly, The Brattle Group's estimate of GAMMA was 44% (55% x 0.80). In applying this estimate, an adjustment was made for the dividend payout ratio (estimated to be 0.70), so that the effective value of GAMMA in The Brattle Group's derivation of a rate of return for the DBNGP was 30.8% (0.70 x 44%).
>
> In his Draft Decision, the Regulator refers to a more recent study that indicates a higher value for the franking ratio, and that consistent application of the Capital Asset Pricing Model in the derivation of a return on equity requires the assumption that all investors are Australian and can fully utilize franking credits. According to the Regulator, these two factors suggest a franking credit utilization factor higher than the 55% assumed by Epic Energy. Further arguments are advanced by the Regulator which purport to show that the transformation method used by Epic Energy (and by the Regulator) to account for the effects of taxation requires assumption of a higher rather than a lower value for GAMMA. On the basis of the additional evidence, and these more theoretical arguments, the Regulator concludes that the appropriate value for GAMMA is that which has been assumed for other regulatory decisions in Australia.
>
> There appears to be no basis for this conclusion, other than the fact that other regulatory decisions have assumed (without justification) a value of GAMMA of 50%, which is higher than the estimate used by Epic Energy.

This matter was addressed in some detail in the Draft Decision.[133] Further analysis of this issue is detailed below.

Epic Energy's advisors derived a formula for the post-tax WACC that, in effect, expressed "gamma" as the following function:

$$g = a \cdot q \cdot k$$

where a is the dividend payout ratio, q is the proportion of franking credits utilised and k is the ratio of franked dividends to total dividends. To derive a value for the "gamma" term, Epic Energy has first derived an average value (or utilisation) of franking credits once delivered to investors (the q term), and has then reduced this to take account of the fact that

[132] Paragraphs 328 and 329 of this Final Decision; Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.44 – 9.47.

[133] Draft Decision, Part B pp 205 – 209.

not all franking credits will be distributed immediately (i.e. dividend payout ratio of less than 100 percent – the a term) and also to take account of the fact that, of the dividends paid out, some may be unfranked (the k term). The q and k terms were derived from Australian empirical estimates of 55 percent and 80 percent respectively, and a dividend payout ratio of 0.70 was assumed, implying an effective gamma value of 0.308.

For the purposes of the Final Decision, the impact of dividend imputation on the cost of capital was analysed on an assumption that value of franking credits *created* (which is relevant when assessing regulated charges) depends upon:

- the value of franking credits (as a proportion of their face value) once distributed to shareholders (the q value); and
- the proportion of franking credits that are actually distributed (or the loss in value associated with a deferral in distribution) (the a value).

The product of these two identities is commonly referred to as the *gamma*.

Evidence cited by the Essential Services Commission of Victoria[134] suggests that a q value of 0.55 (as proposed by Epic Energy) understates the value of franking credits in the hands of investors. Moreover, it is inconsistent with a domestic (segregated-markets) CAPM to have a q value of less than one, as this can only come about because of the presence of foreign investors, given that cash rebates now apply for unused franking credits. This makes the Epic Energy's empirical estimate of q a conservative estimate of the true value.

The distribution ratio (a) is a scaling factor applied to the q value to reflect an assumption that not all franking credits are paid out. Scaling down the q value by the observed payout ratio (as proposed by Epic Energy's advisors at a value of 0.7) is likely to understate the proportion of franking credits that are paid out. This is because firms that can pay fully franked dividends are likely to pay out more of their earnings as dividends (i.e. firms have an incentive to distribute franking credits). A better scaling factor would be the proportion of franking credits distributed in any given year, for which the best available evidence is 82 percent.[135]

In regard to the franking ratio (k), Epic Energy has submitted that "the Regulator referred to a more recent study that indicates a higher value for the franking ratio".[136] This is incorrect. The "franking ratio" adjustment used by Epic Energy's advisors assumed that, if dividends were set at 70 percent of earnings, then these dividends would be only 80 percent franked (which reflects the average franking ratio for all companies – which can only reflect an effective tax rate on average far lower than the statutory rate). As indicated in the Draft Decision, the assumption about the franking ratio must be consistent with the assumption about the amount of taxation paid by Epic Energy. In estimating the WACC for the purposes of the Draft Decision, the forward transformation was used to account for taxation, which is

[134] Essential Services Commission, October 2002, Review of Gas Access Arrangements, Final Decision, p 401.

[135] Hathaway, N. and R. Officer, 1996, The Value of Imputation Tax Credits, Working Paper, Melbourne Business School, p.13. Hathaway and Officer found that the value of franking credits distributed in each year averaged 82 per cent of the value of credits created, which Hathaway and Officer used as a proxy for the proportion of credits created in a year that are distributed.

[136] Epic Energy (WA) Transmission Pty Ltd, 11 December 2002, Submission CDS#2, para 9.46.

equivalent to assuming that the effective tax rate is likely to exceed (rather than fall short of) the statutory rate.[137] Thus the assumption about taxation is equivalent to assuming that Epic Energy will make tax payments that are a far greater proportion of earnings than the average company. Given this assumption about tax, there is no basis for assuming that Epic Energy will not be able to pay fully franked dividends if it distributes 82 percent of its earnings as dividends – indeed this assumption implies that Epic Energy could pay fully franked dividends even if it distributed 100 percent of earnings as dividends (a *k* value equal to one).

[137] The assumption behind the statement that the effective tax rate will exceed the statutory rate is that straight-line (historical-cost) depreciation is used to derive accounting earnings, whereas the implicit assumption in the forward transformation is that taxable income is calculated using the historical-cost equivalent of the regulatory depreciation method, which is likely to imply that depreciation is deferred compared to straight-line historical-cost depreciation. In my Draft Decision, straight-line current cost depreciation was used, which is deferred compared to straight-line historical-cost depreciation.