OFFICE OF GAS ACCESS REGULATION

OffGAR WESTERN AUSTRALIA

# DRAFT DECISION:

# PROPOSED ACCESS ARRANGEMENT

# DAMPIER TO BUNBURY NATURAL GAS PIPELINE

**Submitted by**

**Epic Energy (WA) Transmission Pty Ltd**

**Part B**

**Supporting Information**

**INDEPENDENT GAS PIPELINES ACCESS REGULATOR**

**WESTERN AUSTRALIA**

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# GLOSSARY

Terms used in the Draft Decision have the meanings ascribed to them under the *Gas Pipelines Access (Western Australia) Act 1998* or the proposed Access Arrangement for the DBNGP. Readers should refer to these documents for definitions of specific terms. In order to assist understanding, summary definitions of several terms used widely in this Draft Decision are provided below.

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| Access Arrangement | A statement of policies and the basic terms and conditions that apply to third party access to a Covered Pipeline. |
| Access Arrangement Information | Additional and/or supplemental information pertaining to the Access Arrangement. |
| Access Manual | The DBNGP access manual approved under section 3 of the *Dampier to Bunbury Pipeline Act 1997* or that manual as for the time being amended or substituted in accordance with that section. |
| Access Request | A request for access to a Service made in accordance with the Access Arrangement. |
| Arbitrator | The Office of the Western Australian Gas Disputes Arbitrator established under section 62 of the *Gas Pipelines Access (Western Australia) Act 1998*. |
| Bare Transfers | A transfer by a User of all or part of its contracted capacity on a pipeline not requiring the consent of the Service Provider and as it does not involve a change in the contractual arrangements between the User and the Service Provider. |
| Capacity | The potential of a pipeline, as currently configured and operated in a prudent manner consistent with good pipeline industry practice, to deliver a particular Service between a Receipt Point and a Delivery Point at a point in time. |
| Capacity Management Policy | A policy that is required to be in the Access Arrangement indicating whether the Covered Pipeline is to be administered as a Contract Carriage Pipeline or a Market Carriage Pipeline. |
| Capital Base | Has the meaning given to "Capital Base" in section 8.4 of the Code. |
| Capital Expenditure | Expenditure on a Covered Pipeline and associated regulated assets to be incorporated into the Capital Base of the pipeline. |
| Code | The *National Third Party Access Code for Natural Gas Pipeline Systems.* |
| Code Registrar | Has the meaning given in Gas Pipeline Access Law. |

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| Consent Transfers | A transfer by a User of all or part of its contracted capacity on a pipeline where the transfer is subject to the consent of the Service Provider. |
| Contract Carriage | A system of managing third party access whereby the Service Provider normally manages its ability to provide Services primarily by requiring Users to use no more than the quantity of service specified in a contract (defined in detail in the Code). |
| Contracted Capacity | The nominal quantity of gas transportation to be undertaken under a service agreement between a User and the Service Provider. |
| Covered Pipeline | The whole or particular part of a pipeline which is regulated under the Code. |
| Delivery Point | A point of a pipeline at which the custody of gas is transferred from a Service Provider to a User. |
| Delivery Point MDQ | Means the maximum quantity of gas that the Shipper may require Epic Energy to deliver on a Day at a single Delivery Point as specified in the Access Contract. |
| Depreciated Actual Cost | 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. |
| Depreciated Optimised Replacement Cost | Is the depreciated minimum cost of replacing or replicating the service potential embodied in a pipeline with modern equipment and in the most efficient way practicable, from an engineering perspective, given the service requirements, the age and condition of the existing assets and replacement in the normal course of business. |
| Depreciation Schedule | The Depreciation Schedule is the set of depreciation schedules 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. |
| Distributable Revenue | This term is defined in section 9.2 of the proposed Access Arrangement and is the amount of Rebatable Revenue that is to be distributed between Epic Energy and Shippers. |
| Extensions/ Expansions Policy | A policy that is required to be in the Access Arrangement setting out a method for determining whether extension or expansion to the Covered Pipeline is or is not to be treated as part of the Covered Pipeline for the purposes of the Code. |
| Fixed Period | The period during which a Fixed Principle may not be changed. |

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| Fixed Principle | An element of the Reference Tariff Policy that can not be changed without the agreement of the Service Provider. |
| Haulage Contract | An agreement entered into between a Pipeline Service Provider and a User under which the Pipeline Service Provider agrees to provide a Reference Service on terms and conditions as set out in an Access Arrangement. |
| Incentive Mechanism | Incentive Mechanism has the meaning given to **"**Incentive Mechanism**"** in sections 8.44 and 10.8 of the Code. |
| Information Package | Information required to be provided by the Service Provider to Prospective Users under section 5.1 of the National Third Party Access Code for Natural Gas Pipeline Systems. |
| Initial Capital Base | Initial Capital Base means the Capital Base at the commencement of the Access Arrangement Period. |
| Market Carriage | A system of managing third party access whereby the Service Provider does not normally manage its ability to provide Services primarily by requiring Users to use no more than the quantity of Service specified in a contract (defined in more detail in the Code). |
| Market Variable Element | A factor that has a value assumed in the calculation of a Reference Tariff, where the value of that factor will vary with changing market conditions during the Access Arrangement Period or in future Access Arrangement Periods, and includes the sales or forecast sales of Services, any index used to estimate the general price level, real interest rates, Non-Capital Cost and any costs in the nature of Capital Costs. |
| MDQ | "MDQ" means the aggregate of the Shipper's Delivery Point MDQ's. |
| Minister | Is the Western Australian Minister for Energy unless otherwise indicated. |
| National Gas Pipelines Access Agreement | A national agreement to introduce a national gas pipelines access regime endorsed by CoAG and signed by all Australian Heads of State on 7 November 1997. |
| New Facilities Investment | An increase in the Capital Base of the pipeline after the commencement of a new Access Arrangement Period to reflect additional capital costs incurred in modifying or adding to existing assets for the purpose of providing services. |
| Non-Capital Costs | Non-Capital Costs has the meaning given to **"**Non-Capital Costs**"** in section 8.4 of the Code, which at the date of the publication of this decision was: "...the operating, maintenance and other Non-Capital Costs incurred in providing all Services provided by the Covered Pipeline". |

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| Non-Reference Service | A service other than a Reference Service. |
| Notional Delivery Point | Means a notional Delivery Point specified from time to time in the System Description of the Access Arrangement Information. |
| Operating Expenditure | The Non-Capital Costs incurred by a Service Provider in operating, maintaining and delivering services. |
| Optimised Replacement Cost | Is the minimum cost of replacing or replicating the service potential of an asset with modern equipment in the most efficient way practicable, from an engineering perspective, given specified service requirements. |
| Overrun | Any gas delivered to the Shipper at a Delivery Point in excess of the Shipper's Delivery Point MDQ; or at Delivery Points which in aggregate exceeds the Shipper's MDQ, is Overrun. |
| Prescribed Fee | The non-refundable fee that is required by Epic Energy to accompany an Access Request. |
| Prospective User | A person who seeks or who is reasonably likely to seek to enter into a Service Agreement with a Service Provider and includes a User who seeks or may seek to enter into a Service Agreement for an additional Service. |
| Queuing Policy | A policy that is required to be included in an Access Arrangement which defines the priority that a Prospective User has over another Prospective User to negotiate for specific Capacity. |
| Rate of Return | Rate of Return has the meaning given to **"**Rate of Return**"** in section 8.4 of the Code, which at the date of the publication of this decision was: "...a return (*Rate of Return*) on the value of the capital assets that form the Covered Pipeline (*Capital Base*)." |
| Rebatable Revenue | Revenue obtained from certain Non-Reference Services is Rebatable Revenue in accordance with paragraph 9 of the proposed Access Arrangement. Rebatable Revenue for a year is the sum of the revenue from Rebatable Services in the year. |
| Receipt Point | A point of a pipeline at which the custody of gas is transferred to the Service Provider. |
| Reference Service | A Service that is specified as a Reference Service in an Access Arrangement. |
| Reference Tariff | A tariff specified in an Access Arrangement as corresponding to a Reference Service. |
| Reference Tariff Policy | Has the meaning given in section 3.5 of the *National Third Party Access Code for Natural Gas Pipeline Systems.* |

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| Regulator | The Independent Gas Pipelines Access Regulator in Western Australia established under section 27 of the *Gas Pipelines Access (Western Australia) Act 1998.* |
| Residual Value | The value of the Capital Base at the end of the Access Arrangement Period after allowing for Capital Expenditure, Redundant Capital and Depreciation during the Period. |
| Revisions Commencement Date | A date upon which the next revisions to the Access Arrangement are intended to commence. |
| Revisions Submissions Date | A date upon which the Service Provider must submit revisions to the Access Arrangement. |
| Ring Fencing | A requirement on a Service Provider to establish arrangements to segregate or "ring fence" its business of providing Services using a Covered Pipeline from other business activities. |
| Scheme Participant | Scheme Participant means the State of Western Australia as defined in section 11 of the *Gas Pipelines Access (Western Australia) Act 1998*. |
| Service | A Reference Service or Non-Reference Service relating to the transportation of gas by a Service Provider, and in the case of a Service Agreement means the particular Reference Service or Non-Reference Service the subject of that Service Agreement. |
| Service Agreement | An agreement between a Service Provider and a User for the provision of a Service. |
| Services Policy | An Access Arrangement must include a policy on the Services to be offered, including a description of one or more Services. A Services Policy commits a Service Provider to making available Reference Services to Prospective Users, and for the provision of Non-Reference Services to Prospective Users. |
| Service Provider | In relation to a pipeline or proposed pipeline, means the person who is, or who is to be, the owner or operator of the whole or any part of the pipeline or proposed pipeline. |
| Shipper | Refer to definition for "User". |
| Structural Element | Any principle or methodology that is used in the calculation of a Reference Tariff where that principle or methodology is not a Market Variable Element and has been structured for Reference Tariff making purposes over a longer period than a single Access Arrangement Period. |
| Threshold Revenue | Has the meaning in paragraph 9.2 of the proposed Access Arrangement. |

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| Total Revenue | Total Revenue has the meaning given in section 8.2 of the Code, which says it is the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement period. |
| Trading Policy | A policy that is required to be in the Access Arrangement for a Contract Carriage Pipeline, as required by section 3.9 of the Code, regarding trading capacity and the rights of a User to trade its rights to obtain a Service to another person. |
| User | A person who has a current Service Agreement or an entitlement to a Service as a result of arbitration under Section 6 of the Code. In the proposed Access Arrangement for the DBNGP, Epic Energy has used the term "Shipper" to refer to a User of the DBNGP. In this Draft Decision, the term "User" is used when discussing either Users of pipelines generally or a user of the DBNGP. The term "Shipper" is used when making direct reference to a clause of the proposed Access Arrangement and associated documents, however a "User" of the DBNGP is synonymous with a "Shipper" under the terms of the proposed Access Arrangement. |

# ABBREVIATIONS

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|---|---|
| ACCC | Australian Competition and Consumer Commission |
| CAPM | Capital Asset Pricing Model |
| CMS | CMS Gas Transmission of Australia Pty Ltd |
| CoAG | Council of Australian Governments |
| CPI | Consumer Price Index |
| DAC | Depreciated Actual Cost |
| DBNGP | Dampier to Bunbury Natural Gas Pipeline |
| DORC | Depreciated Optimised Replacement Cost |
| GJ | Gigajoules ($10^9$ joules) |
| GST | Goods and Services Tax |
| IPARC | Independent Pricing and Access Regulatory Commission (ACT) |
| IPART | Independent Pricing And Regulatory Tribunal (New South Wales) |
| IRR | Internal Rate of Return |
| kPa | Kilopascals |
| LNG | Liquefied Natural Gas |
| LPG | Liquefied Petroleum Gas |
| MDQ | Maximum Daily Quantity |
| MMI | Man Machine Interface |
| NCC | National Competition Council |
| NPV | Net Present Value |
| O*ff*GAR | Office of Gas Access Regulation |
| ORG | Office of the Regulator General (Victoria) |
| PJ | Petajoules ($10^{15}$ joules) |
| TLPG | Tempered Liquefied Petroleum Gas |
| TJ | Terajoules ($10^{12}$ joules) |
| WACC | Weighted Average Cost of Capital |

# 1 INTRODUCTION

On 15 December 1999 Epic Energy (WA) Transmission Pty Ltd (Epic Energy) submitted a proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) to the Western Australian Independent Gas Pipelines Access Regulator (the Regulator) for approval under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code).

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, main line valves, lateral pipelines, delivery stations, metering stations, operating and communication facilities, and odorising facilities.

The Regulator assessed the proposed Access Arrangement against the requirements and principles of the *Gas Pipelines Access (Western Australia) Act 1998*, which gives effect to the *Gas Pipelines Access (Western Australia) Law*, including the Code. As part of this assessment, the Regulator considered issues addressed in submissions made on the proposed Access Arrangement by interested parties.

This Part B of this Draft Decision details the analysis and provides background and supporting information on which the Draft Decision is based.

In preparing the Draft Decision, the Regulator assessed the proposed Access Arrangement on the basis of three broad criteria:

i. whether the proposed Access Arrangement meets the requirements of sections 3.1 to 3.20 of the Code that explicitly state the matters that must be addressed in an Access Arrangement;

ii. whether the proposed Reference Tariffs are consistent with the objectives of section 8 of the Code and were determined in accordance with the principles set out in section 8; and

iii. whether the inclusion and substance of matters included in the proposed Access Arrangement, but not required by sections 3 or 8 of the Code, are reasonable having regard to the interests of the Service Provider, Prospective Users, Users, the public interest and other considerations provided for in section 2.24 of the Code.

The supporting information set out in this part is generally organised such that matters relevant to assessment of the proposed Access Arrangement are addressed in the same sequence as in the Code. There are, however, several areas of overlap and cross-reference between different parts of the Code that would cause excessive repetition if this sequence were rigorously adhered to. The supporting information is thus broadly structured as follows.

- Background information on the regulatory framework within which an Access Arrangement is assessed.
- The process for assessment of an Access Arrangement, and in particular the proposed Access Arrangement for the DBNGP.
- Assessment of matters addressed by the proposed Access Arrangement other than those that relate to tariffs, fees and charges (non-tariff matters).
- Assessment of Reference Tariffs proposed for the DBNGP.
- Assessment of penalties fees and charges, other than tariffs, proposed for the DBNGP.
- Responses to any additional matters raised in public submissions.

# 2 REGULATORY FRAMEWORK

## 2.1 THE WESTERN AUSTRALIAN GAS INDUSTRY

### Gas Production

Western Australia and its immediate offshore areas possess significant resources of natural gas, holding more than three quarters of the identified natural gas reserves within Australia. Natural gas accounts for 40 percent of the State's identified energy resources.[5] There are five sedimentary basins in this area, with two of these basins – the Northern Perth Basin and the Carnarvon Basin – currently producing natural gas for sale. There are nine processing facilities currently supplying natural gas to the domestic market, indicated as follows.

| Carnarvon Basin | Northern Perth Basin |
|---|---|
| North West Shelf | Dongara |
| Harriet Gas Gathering | Woodada |
| Tubridgi Onshore Gas | Beharra Springs |
| Griffin Oil/Gas | |
| Roller/Skate Oil/Gas | |
| East Spar | |

In 1999/2000 approximately 780 PJ of natural gas was produced from the two major basins, with the majority originating from the Carnarvon Basin. The natural gas produced from these areas is either sold to the domestic Western Australian market or exported in the form of liquefied natural gas (LNG). Naturally occurring liquefied petroleum gas (LPG) is also produced from the Carnarvon Basin.

### *Gas Pipeline Infrastructure*

There are currently five onshore natural gas transmission pipelines "covered" by the Code in Western Australia - the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline, the Parmelia Pipeline, the Tubridgi Pipeline System and the Kambalda Lateral.

The Epic Energy owned DBNGP transports gas from the North West Shelf to residential, business and industrial customers in the Carnarvon, Geraldton, Perth, Mandurah and Bunbury areas. The pipeline system comprises a main pipeline and laterals, with a total length of 1845 km and current delivery capacity of about 600 TJ/day to Delivery Points in, and south of, the Perth metropolitan region (downstream of Compressor Station 9).

The Goldfields Gas Pipeline runs 1,378 kilometres from the North West of Western Australia to the Northern and Eastern Goldfield areas and is owned by Goldfields Gas Transmission Pty Ltd, a private consortium comprising Southern Cross Pipelines Australia Pty Ltd, Southern Cross Pipelines (NPL) Australia Pty Ltd and Duke Energy. The Goldfields Gas Pipeline has a current capacity of around 95 TJ/day, but can reach 160 TJ/day when fully compressed.

[5] Office of Energy, 2000. Energy Western Australia 2000, p.27.

The Parmelia Pipeline, previously the Western Australian Natural Gas (WANG) pipeline, was commissioned in 1971 and transports gas from various fields in the Northern Perth Basin to a number of major industrial customers in the South West of the State. The pipeline is owned by CMS Energy Corporation and is operated by CMS Gas Transmission of Australia. With additional compression installed, the pipeline would be capable of delivering up to 120 TJ/day, including transport of gas from Dongara, the North West Shelf (via an interconnection with the DBNGP), the Beharra Springs field and the Woodada field.

## 2.2 NATIONAL GAS ACCESS REGIME

In February 1994, the Council of Australian Governments (CoAG) agreed to progress a number of reforms to promote free and fair trade in natural gas in Australia. These reforms included the development of a uniform national framework for the regulation of third-party access to natural gas transmission pipelines.

On 7 November 1997, CoAG endorsed a national regulatory regime for natural gas pipelines in Australia, including distribution pipelines. This occurred through the signing of the Gas Pipelines Access Agreement (the Agreement), which amongst other things records each jurisdiction's commitment in relation to implementing the national regime and maintaining the integrity of the Agreement.

As provided for under the Agreement, the legislation put in place in Western Australia has an essentially identical effect to the *Gas Pipelines Access (South Australia) Act 1997*.

## 2.3 THE WESTERN AUSTRALIAN ACCESS REGIME

### Legislation

The Access Regime established by the *Gas Pipelines Access (Western Australia) Act 1998* comprises the following four elements:

i. The Act itself that gives effect to the *Gas Pipelines Access (Western Australia) Law*.

ii. Schedule 1 that provides the legal framework for the operation of the Access Regime.

iii. Schedule 2 which is the Code and that contains the detailed access principles of the Access Regime.

iv. Schedule 3 that contains consequential amendments to certain Acts.

### The Gas Pipelines Access (Western Australia) Act 1998

The Western Australian Act makes provision for the following matters:

- Extension of the coverage of the Code to include liquefied petroleum gas (LPG) and tempered LPG (TLPG) (section 8 of the Act).
- Application of the *Gas Pipelines Access Law* as a law in Western Australia (section 9 of the Act).
- Provision for the making of regulations and the application of those regulations in Western Australia (sections 10, 12, 13, and 14 of the Act).
- Definition of the various bodies exercising functions under the Code in Western Australia (section 11 of the Act).
- Conferral of functions and powers on the various Commonwealth and State Code bodies and the Federal Court (sections 15 to 21 of the Act).

- Application of the Commonwealth *Administrative Decisions (Judicial Review) Act 1972* to certain decisions made under the Code (section 22 of the Act).
- Exemption from State taxes for the transfer of assets or liabilities when complying with ring fencing requirements of the Code. The Western Australian Act also contains a clarification that is not contained in the legislation of other jurisdictions that the Regulator may include tax liabilities when assessing the administrative costs of complying with ring fencing obligations of the Code (section 23 of the Act), although such provision has since been included in the Code (section 4.15A of the Code).
- Establishment of the Western Australian Independent Gas Pipelines Access Regulator (the Regulator) who will act as the Regulator for the purposes of the Law and the Code for distribution and transmission pipelines in Western Australia (sections 26 to 48 of the Act).

  Features of the Regulator's role are as follows:

  – The Regulator is entirely independent of direction or control by the Crown or any Minister or officer of the Crown in exercising its functions under the Law, Code or Agreement.

  – The Regulator is appointed by the Governor for terms of 3 to 5 years and can only be removed from office by both Houses of Parliament.

  – The Minister sets the annual expenditure limit for the Regulator but otherwise the Regulator is free to expend the monies within that limit and subject to the prudent financial controls in the *Financial Administration and Audit Act 1985* (including the audit by the Auditor General).

  – The Minister may issue directions to the Regulator on general policies to be followed in matters of administration and financial administration, but such directions cannot constrain the Regulator with respect to the performance of any function conferred on the Regulator under the Access Regime or the Agreement. Such Directions are to be tabled in both Houses of Parliament, and must be Gazetted and a copy provided to the Code Registrar. The text of any Direction is also to be included in the Annual Report of the Regulator.

  – Where the Regulator, in assessing a proposed Access Arrangement, is required by the Code to take the public interest into account the Regulator is required to, amongst other things, take into account the fixing of appropriate charges as a means of extending effective competition in the supply of natural gas to residential and small business customers.

  – The Regulator is required to notify the Minister of any conflict of interest with his/her duties.

  – Funding of functions under the Act is through fees determined under the *Gas Pipelines Access (Western Australia) (Funding) Regulations 1999* that became effective on 14 January 2000.
- The effectiveness of the operation of the Regulator for transmission pipelines will be reviewed when a significant gas transmission pipeline crosses Western Australia's border or after the 7 November 2002 (whichever is the earlier).
- Establishment of the Western Australian Gas Review Board to act as the appeals body for certain purposes under the Law and the Code. The Gas Review Board consists of a presiding member to be chosen from a panel of legal practitioners by the Attorney–

General, and two experts chosen from a panel of experts by the presiding member (sections 49 to 60 of the Act).

- Establishment of the Western Australian Gas Disputes Arbitrator for the purposes of the Law and the Code and of hearing of disputes under the *Gas Referee Regulations 1995* (sections 61 to 85 of the Act).

  Features of the Gas Disputes Arbitrator's role are as follows:

  – The Arbitrator is entirely independent of direction or control by the Crown or any Minister or officer of the Crown.

  – The Arbitrator is appointed by the Governor for terms of 3 to 5 years and can only be removed from office by both Houses of Parliament.

  – The Minister may issue directions to the Arbitrator on general policies to be followed in matters of administration and financial administration, but such directions cannot constrain the Arbitrator with respect to the performance of any function conferred on it under the Access Regime or the Agreement, or other access regimes such as the transitional Dampier to Bunbury Natural Gas Pipeline regime. Such Directions are to be tabled in both Houses of Parliament, and must be Gazetted and copies provided to any person on request.

- Making of regulations including the setting of fees and charges for the Regulator, the Board and the Arbitrator (section 87 of the Act).

- Transitional provisions (sections 89 to 97 of the Act).

**Schedule 1 of the Gas Pipelines Access (Western Australia) Act 1998**

Schedule 1 of the Act contains the provisions necessary to give the Code legal effect including provisions, as follows:

- Definition of the Code and providing for its amendment (sections 5 and 6 of schedule 1, when read in conjunction with the definition of scheme participants in section 3 and other definitions in section 2).

- Establishment of a procedure for classifying pipelines as transmission or distribution pipelines and for determining which jurisdiction a cross-border distribution pipeline is most closely connected with (sections 9 to 11 of schedule 1). This is done for the purposes of defining which Code body will have jurisdiction under the Code.

- Prohibition of certain persons preventing or hindering access to Code pipelines (section 13 of schedule 1).

- Establishment of procedures for arbitrating access disputes under the Code (sections 14 to 31 of schedule 1).

- Provision for legal proceedings to be brought to the Supreme Court in relation to breaches of certain provisions of the Law and the Code (sections 32 to 37 of schedule 1).

- Establishment of a right of administrative review of certain decisions made under the Code (sections 38 to 39 of schedule 1).

- Placing of an obligation on producers of natural gas who offer to supply delivered gas to also offer to supply gas at the exit flange of the producer's processing plant (section 40 of schedule 1).

- General provisions relating to the Regulator's ability to obtain information and documents (sections 41 to 43 of schedule 1).

The Law is applied as a law in Western Australia by the *Gas Pipelines Access (Western Australia) Act 1998*, as well as in each other state and territory by their respective Acts.

**Schedule 2 of the Gas Pipelines Access (Western Australia) Act 1998**

Schedule 2 of the Act comprises the Code. This is identical to the access code appearing in Annex D to the Agreement and in Schedule 2 to the South Australian Act and the respective Acts of other states and territories. The Code is applied as a law in Western Australia and establishes, amongst other things, the following:

- A mechanism by which natural gas pipelines become subject to the Code (called "Covered Pipelines" or "Code Pipelines") (section 1 of the Code). Schedule A to the Code lists the pipelines that were initially covered by the Code in Western Australia.
- A requirement that the Service Provider (i.e. owner/operator) of a Covered Pipeline establish with the relevant Regulator an up-front Access Arrangement setting out the terms on which access will be given to certain services provided by the Covered Pipeline, including the Reference Tariffs for such services (section 2 of the Code). The content of an Access Arrangement (section 3 of the Code) and the principles, which must be applied in setting the Reference Tariffs (section 8 of the Code), are also specified.
- A right to arbitration where a Service Provider of a Covered Pipeline and a Prospective User cannot agree on the terms of access to a service. The arbitrator is obliged in any such arbitration to apply the terms of the relevant Access Arrangement established with the relevant Regulator (section 6 of the Code).
- Obligations on Service Providers of Covered Pipelines to ring fence their operations (section 4 of the Code).
- Obligations on Service Providers and Users to disclose information (section 5 of the Code).
- A requirement that the Service Provider of a Covered Pipeline not enter into contracts with associates without first obtaining the approval of the relevant Regulator (section 7 of the Code).

## 2.4 SPECIFIC REGULATORY ARRANGEMENTS FOR THE DBNGP

### Legislative Background

Prior to commencement of the *Gas Pipelines Access (Western Australia) Act 1998*, third party access to natural gas pipelines within Western Australia was regulated under either the *Petroleum Pipelines Act 1969* or the *Petroleum (Submerged Lands) Act 1982* for transmission pipelines or under specific legislation for particular transmission and distribution pipeline systems. Access to the DBNGP has been regulated under specific legislation since 1994.

In 1994, ownership of the DBNGP was passed to the Gas Corporation (trading as AlintaGas) established under the *Gas Corporation Act 1994*. Under sections 91 and 95 of the *Gas Corporation Act 1994*, the *Gas Transmission Regulations 1994* regulated access to the transmission capacity of the DBNGP according to certain terms and conditions. A number of Users (referred to in the *Gas Transmission Regulations 1994* as “Shippers”) entered into access contracts under these regulations. Many of those contracts currently operate. The *Gas Corporation Act 1994* and *Gas Transmission Regulations 1994* were ultimately repealed under the *Gas Corporation (Business Disposal) Act 1999* that provided for the privatisation of the DBNGP.

The privatisation of the DBNGP involved its sale by the Gas Corporation to Epic Energy. The State Government managed the sale under a tender process. It should be noted that, subsequent to the sale of the DBNGP, AlintaGas was itself privatised and is no longer the same entity as the Gas Corporation.

As part of the process of privatisation of the DBNGP, the *Dampier to Bunbury Pipeline Act 1997* was enacted and subsequently assented to in December 1997. Broadly, this Act and the subordinate *Dampier to Bunbury Pipeline Regulations 1998*, provide for the process of disposal of the DBNGP, the assignment of various things necessary to give effect to the disposal including contracts previously entered into under the *Gas Transmission Regulations 1994*, rights of third-party access to the transmission capacity of the DBNGP and related matters. Additionally, the Act and regulations provide for access to the DBNGP according to the DBNGP Access Manual, approved by the Coordinator of Energy in March 1998. The Access Manual sets out the terms and conditions upon which access contracts will be entered into.

The access scheme implemented under the *Dampier to Bunbury Pipeline Act 1997* has now been superseded by the provisions of the *Gas Pipelines Access (Western Australia) Act 1998*. Under section 95 of the *Gas Pipelines Access (Western Australia) Act 1998*, the access arrangements for the privatised DBNGP system are taken to be an approved Access Arrangement under the Code until 1 January 2000. Thereafter, Epic Energy is obliged to submit, as it has, a proposed Access Arrangement to the Regulator for approval. Sections 7 and 8 of schedule 3 to the *Gas Pipelines Access (Western Australia) Act 1998* have the effect of repealing Part 5 of the *Dampier to Bunbury Pipeline Act 1997* and the whole of the *Dampier to Bunbury Pipeline Regulations 1998* as of 1 January 2000, but these continue to operate as a transitional access scheme until the proposed Access Arrangement is approved.

### Existing Contracts

The position of contracts for access to the transmission capacity of the DBNGP in force immediately before the approval of the proposed Access Arrangement is discussed in detail in the relevant parts of this Draft Decision, such as whether a T1 Service should be required (section 4.2). The following is a summary discussion of this and how such existing contracts may be affected. This discussion is provided for the general information of readers.

Under sub-section 96(1) of the *Gas Pipelines Access (Western Australia) Act 1998*, existing contracts are not affected in their continuance or operation by the Code. They will continue to operate according to their terms and conditions, which may be as set out in the DBNGP Access Manual or the *Gas Transmission Regulations 1994*, as applicable. However section 96 of this Act makes some provision for transition from existing contracts to contracts for Services under the Access Arrangement. Transition could potentially occur in two ways: transition to a new statutory price that is the same as, or derived from, a Reference Tariff under the Access Arrangement; or transition to a new contract that gives effect to the terms and conditions of a Service under the Access Arrangement. These two mechanisms of transition are described as follows.

1. Transition to a statutory price that is the same as, or derived from, a Reference Tariff under the Access Arrangement.

   Section 20 of the *Dampier to Bunbury Pipeline Act 1997* provides a mechanism by which Users under existing contracts may obtain the benefit of reducing prices for gas transmission through the DBNGP.

   Sub-section 20(1) of the *Dampier to Bunbury Pipeline Act 1997* provides:

> Despite anything to the contrary in a contract under which an assignee assumes the position of the corporation under this Part, the assignee is to offer to vary the price for access to which a person is entitled under the contract to a price not exceeding the statutory price applicable from time to time for the service provided for in the contract.

The phrase "statutory price" is defined in sub-section 20(5) as:

> … the price that a person could insist on paying if the person were, at the time concerned, entering into a contract for the service concerned.

The operation of section 20 of the *Dampier to Bunbury Pipeline Act 1997* is preserved by paragraph 96(2)(a) of the *Gas Pipelines Access (Western Australia) Act 1998* despite the advent of regulation of third party access under the Code. The process by which section 20 may operate under the proposed Access Arrangement is somewhat ambiguous, being an outcome of repeal of the *Dampier to Bunbury Pipeline Regulations 1998*.

Regulation 35 of the *Dampier to Bunbury Pipeline Regulations 1998* sets out access prices for 1998 and 1999. Regulation 36 specifies these are the relevant statutory prices for the purposes of section 20. Under schedule 1 of the *Gas Pipelines Access (Privatised DBNGP System) (Transitional) Regulations 1999*, regulation 35 is amended to specify maximum capacity reservation charges and commodity charges for T1 and T2 capacity from 1 January 2000, which apply until such time as the proposed Access Arrangement is approved. For existing contracts, those prices will apply until the end of the contracts unless the contracts are varied by agreement between the parties to the contracts.

Regulation 36 of the *Dampier to Bunbury Pipeline Regulations 1998* also specifies there is no statutory price for the purposes of section 20 other than those specified in regulation 35. If it were not for the repeal of the *Dampier to Bunbury Pipeline Regulations 1998* under the *Gas Pipelines Access (Western Australia) Act 1998*, then regulation 36 would prevent any argument to the effect that the Reference Tariff under the proposed Access Arrangement may constitute the relevant statutory price. However, since regulation 36 will cease to exist after approval of the proposed Access Arrangement, section 20 of the *Gas Pipelines Access (Western Australia) Act 1998* will continue to operate without any express restriction on the price (if any) that may constitute the relevant statutory price.

Therefore, after the Regulator approves an Access Arrangement for the DBNGP there will not be any specified statutory price for the purposes of section 20 of the *Dampier to Bunbury Pipeline Act 1997*, unless there is a price under (or capable of being derived from) the Access Arrangement which corresponds with the service presently being provided (for example, the T1 Service). The effect of this is, in the Regulator's view, to oblige Epic Energy to offer to vary the price for access under existing contracts to a Reference Tariff for a Reference Service if Reference Services exist that are considered equivalent to the T1 Service and/or T2 Service. The question of whether Epic Energy should, under the Access Arrangement, offer a Reference Service that is equivalent to the T1 Service is addressed in section 4.2 of Part B of this Draft Decision.

2. Variation of existing contracts

Regardless of section 20 of the *Dampier to Bunbury Pipeline Act 1997* and the provisions discussed above for transition under existing contracts to the Reference Tariff, under paragraph 96(2)(b) of the *Gas Pipelines Access (Western Australia) Act 1998* the parties to a contract entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998* may, if they wish, elect to vary their contract or enter into a fresh contract to give effect to the terms and conditions of the approved Access Arrangement. It is noted, however, that the provisions of section 96(2)(b) are, for all practical purposes, merely declaratory as it is generally open for the parties to a contract to renegotiate that contract. Paragraph 96(2)(b) does not give any party to a contract any right to unilaterally alter or terminate that contract.

# 3 ASSESSMENT PROCESS

## 3.1 OVERVIEW

Where a pipeline is covered by the Code there is a requirement for a pipeline Service Provider to establish an Access Arrangement. The Regulator may approve a proposed Access Arrangement only if it is considered by the Regulator to satisfy the minimum requirements set out in section 3 of the Code. The Regulator must not refuse to approve an Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that section 3 does not require an Access Arrangement to address. Subject to this limitation, the Regulator has a broad discretion to refuse to accept an Access Arrangement.

An Access Arrangement submitted to the Regulator for approval must be accompanied by specified Access Arrangement Information. The purpose of the Access Arrangement Information is to enable Users and Prospective Users to understand the derivation of the elements of the proposed Access Arrangement and form an opinion as to the compliance of the Access Arrangement with the Code.

The process by which an Access Arrangement is assessed and approved can be summarised as follows:

- The Service Provider submits a proposed Access Arrangement, together with the Access Arrangement Information, to the Regulator.
- The Regulator may require the Service Provider to amend and resubmit the Access Arrangement Information.
- The Regulator publishes a public notice and seeks submissions on the application.
- After considering submissions, the Regulator issues a Draft Decision that either:
  - proposes to approve the Access Arrangement; or
  - proposes not to approve the Access Arrangement and states the revisions to the Access Arrangement which would be required before the Regulator would approve it; or approves a revised Access Arrangement submitted by the Service Provider which incorporates amendments specified by the Regulator in its Draft Decision.
- The Regulator publishes a public notice and seeks submissions on the Draft Decision.
- If the Regulator proposes not to approve the Access Arrangement, the Service Provider may resubmit the Access Arrangement, revised so as to incorporate or substantially incorporate the revisions required by the Regulator, or otherwise addresses the matters the Regulator identified in its Draft Decision as being the reasons for requiring the amendments specified in its Draft Decision.
- After considering submissions on the Draft Decision, the Regulator:
  - if the Service Provider has not submitted a revised Access Arrangement, either approves the Access Arrangement as initially submitted, or does not approve the Access Arrangement and states the amendments or nature of amendments which would have to be made to the Access Arrangement in order for the Regulator to approve it, and the date by which a revised Access Arrangement must be resubmitted by the Service Provider; or

   – if the Service Provider has submitted a revised Access Arrangement, either approves the revised Access Arrangement, or does not approve the Access Arrangement and states the amendments or nature of amendments which would have to be made to the Access Arrangement in order for the Regulator to approve it, and the date by which a revised Access Arrangement must be resubmitted by the Service Provider.

- If the Regulator did not approve the Access Arrangement in the Final Decision and the Service Provider submits a revised Access Arrangement by the date specified by the Regulator, which the Regulator is satisfied incorporates or substantially incorporates the revisions required by the Regulator, or otherwise addresses the matters the Regulator identified in the Final Decision as being the reasons for requiring the amendments specified in its Final Decision, the Regulator approves the Access Arrangement.
- If the Regulator did not approve the Access Arrangement in the Final Decision and the Service Provider does not submit a revised Access Arrangement by the due date or submits a revised Access Arrangement which the Regulator is not satisfied incorporates or substantially incorporates the revisions required by the Regulator, or otherwise addresses the matters the Regulator identified in the Final Decision as being the reasons for requiring the amendments specified in the Final Decision, the Regulator may draft and approve an Access Arrangement.

The *Gas Pipeline Access (Western Australia) Law* provides a mechanism for the review of a decision by the Regulator to impose an Access Arrangement.

The particular components of the assessment process for the Access Arrangement submitted for the DBNGP are described below.

### 3.2 SUBMISSION OF THE ACCESS ARRANGEMENT AND SUPPORTING INFORMATION

Epic Energy submitted proposed Access Arrangement documentation to the Regulator on 15 December 1999, comprising the proposed Access Arrangement, Access Arrangement Information, and Access Contract Terms and Conditions. Additional supporting documents were subsequently provided to the Regulator, and a revised Access Arrangement Information was submitted on 28 July 2000. The total set of documents received by the Regulator was as follows:

- *Proposed Access Arrangement under the National Access Code* (15 December 1999), incorporating:
  - *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).

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).

The Regulator presupposes that the Proposed Access Guide submitted by Epic Energy 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. The Regulator considers that the Proposed Access Guide does not constitute part of the proposed Access Arrangement that is the subject of this Draft Decision. While section 5.2 of the Code provides for the Regulator to require the Service Provider to amend or include additional information in the Information Package under certain circumstances, any related assessment of the Information Package would be undertaken by the Regulator as a separate exercise to the process of approval of the proposed Access Arrangement.

### 3.3 FIRST–ROUND PUBLIC CONSULTATION

O*ff*GAR undertook actions to provide public notification of receipt of the proposed Access Arrangement and invited submissions from interested parties. The actions undertaken by the Regulator in respect of public consultation was as follows:

- Issue on 17 December 1999 of notices to registered interested parties advising of receipt of the proposed Access Arrangement.
- Issue on 17 December 1999 of notices to registered interested parties calling for submissions on the proposed Access Arrangement, with a submission closing date initially set at 4 February 2000 but subsequently extended by further notices to 3 March 2000, and then 17 March 2000.
- Placing of advertisements calling for public submissions in *The West Australian* and the *Australian* (Wednesday 22 December 1999).
- Issue on 20 April 2000 of notices to registered interested parties calling for further submissions on the proposed Access Arrangement, with a closing date of 12 May 2000.
- Issue on 12 January 2000 of an Issues Paper to assist interested parties in making public submissions on the proposed Access Arrangement for the DBNGP.

Documentation submitted by Epic Energy for the proposed Access Arrangement was made available from the O*ff*GAR office and on the O*ff*GAR web site.

Submissions were received from the following parties:

- Apache Energy Limited (20 March 2000).
- AGL Sales and Marketing Limited (17 March 2000).
- AlintaGas:[6]
  - Submission 1 (11 January 2000).
  - Submission 2 (21 January 2000).
  - Submission 3 (20 March 2000).

[6] Submissions from AlintaGas were made at a time prior to the sale of the AlintaGas business and when AlintaGas was the trading name of the State-owned Gas Corporation.

  - Submission 4 (19 May 2000).
- Australian Council for Infrastructure Development Limited (29 February 2000).
- Australian Gas Light Company (AGL) (24 January 2000).
- Bunbury – Wellington Economic Alliance (16 March 2000).
- Bunbury Chamber of Commerce and Industries Inc. (29 February 2000).
- Chamber of Commerce and Industry Western Australia (17 March 2000).
- Chamber of Minerals and Energy of Western Australia Inc. (17 March 2000).
- CMS Gas Transmission of Australia (17 March 2000).
- Cockburn Cement Limited (17 March 2000).
- Combustion Air Pty Ltd (17 March 2000).
- Energy Markets Reform Forum (25 January 2000).
- Hamersley Iron Pty Limited (1 March 2000).
- Mark Neville MLC (24 January 2000).
- North West Shelf Gas (NWSG) (17 March 2000).
- Robe River Mining Co Pty Ltd (1 March 2000).
- Samag Limited (5 April 2000).
- South West Development Commission (17 March 2000).
- The Australian Gas Users Group (21 February 2000).
- Wesfarmers Limited (16 March 2000).
- Wesfarmers CSBP (16 March 2000).
- Western Australian Treasury and Office of Energy (joint submission, 4 February 2000).
- Western Power Corporation (Western Power):
  - Submission 1 (17 February 2000).
  - Submission 2 (17 February 2000).
  - Submission 3 (22 February 2000).
  - Submission 4 (16 March 2000).
  - Submission 5 (16 March 2000).
  - Submission 6 (11 May 2000).
  - Submission 7 (19 May 2000).
- WMC Resources Limited (WMC) (undated: c.9 March 2000).
- Worsley Alumina (11 February 2000).

A late submission from the Goldfields Esperance Development Commission dated 4 April 2001 was received and will be published on the O*ff*GAR web site once this Draft Decision is released.

Epic Energy also made public submissions to the Regulator responding to matters raised in public submissions and to requests for information made by the Regulator during the course of assessment of the proposed Access Arrangement. These submissions are listed as follows:

- Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline – Weighted Average Cost of Capital (16 February 2000).
- Proposed Regulatory Model for the Dampier to Bunbury Natural Gas Pipeline October 1999, Submission Public Version (28 February 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission No. 3, 17 March 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission 4: The Regulatory Compact, 12 May 2000, Public Version).
- Proposed Access Arrangement Submission under the National Access Code (Submission 5: Capital Base, Depreciation and WACC, 12 May 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission 6: Reference Service and Other Services, 12 May 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission 7: Reference Tariff and Incentive Mechanism, 12 May 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission 8: Should a T1 Service be Offered? 12 May 2000).
- Proposed Access Arrangement Submission under the National Access Code (Submission 9: Gaining Access to the DBNGP, 12 May 2000).

In addition to these submissions the Regulator has several additional papers from Epic Energy, and several responses to Information Requests from O*ff*GAR, providing information on various matters. As many of these are confidential they have not been published.

### 3.4 DRAFT DECISION

This document comprises the Regulator's Draft Decision in respect of the proposed Access Arrangement submitted for the DBNGP. The Draft Decision is a result of an assessment by the Regulator of compliance of the proposed Access Arrangement with requirements of the Code. The Draft Decision states the amendments (or the nature of amendments) that are required to be made to the proposed Access Arrangement before the Regulator will approve it.

The Draft Decision provides an opportunity for the Service Provider to make any amendments to the proposed Access Arrangement deemed necessary by the Regulator prior to the Final Decision on acceptance or rejection of the proposed Access Arrangement. Publication of the Draft Decision also provides an opportunity for public comment on the Regulator's assessment of the proposed Access Arrangement.

### 3.5 SECOND–ROUND PUBLIC CONSULTATION

Public submissions are invited on the Draft Decision. In accordance with the requirements of Section 2.14 of the Code, a copy of this document has been provided to all persons that made a submission as part of the first round of public consultation. Copies of the document are available in hard-copy form from O*ff*GAR and the document is also available for downloading from the O*ff*GAR web site.

The closing date for receipt of submissions on the Draft Decision is 5 pm WST 10 August 2001.

### 3.6 FINAL DECISION

In accordance with section 2.16 of the Code, the Regulator will, after consideration of submissions on the Draft Decision, issue a Final Decision which:

– if Epic Energy has not submitted a revised Access Arrangement, either approves the Access Arrangement as initially submitted, or does not approve the Access Arrangement and states the amendments or nature of amendments which would have to be made to the Access Arrangement in order for the Regulator to approve it, and the date by which a revised Access Arrangement must be resubmitted by the Epic Energy; or

– if Epic Energy has submitted a revised Access Arrangement, either approves the revised Access Arrangement, or does not approve the Access Arrangement and states the amendments or nature of amendments which would have to be made to the Access Arrangement in order for the Regulator to approve it, and the date by which a revised Access Arrangement must be resubmitted by the Epic Energy.

In accordance with requirements of section 2.17 of the Code, a copy of the Regulator's Final Decision will be provided to all persons that made a submission in respect of the proposed Access Arrangement or Draft Decision, and copies will be made publicly available in hard-copy form and via O*ff*GAR's web site.

### 3.7 ADDITIONAL AMENDMENTS TO THE PROPOSED ACCESS ARRANGEMENT

If the Regulator does not approve the proposed Access Arrangement and Epic Energy submits a revised Access Arrangement by the date specified by the Regulator under paragraph 2.16(b) of the Code, which the Regulator is satisfied incorporates or substantially incorporates the revisions required by the Regulator, or otherwise addresses the matters the Regulator identified in its Final Decision as being the reasons for requiring the amendments specified in its Final Decision, the Regulator will issue a (further) Final Decision that approves the revised Access Arrangement.

If the Regulator does not approve the proposed Access Arrangement and Epic Energy does not submit a revised Access Arrangement by the date specified by the Regulator under paragraph 2.16(b) of the Code or submits a revised Access Arrangement which the Regulator is not satisfied incorporates or substantially incorporates the revisions required by the Regulator, or otherwise addresses the matters the Regulator identified in its Final Decision as being the reasons for requiring the amendments specified in its Final Decision, the Regulator may draft and approve an Access Arrangement. This would be undertaken in accordance with requirements for public consultation specified in section 2.23 of the Code.

# 4 NON-TARIFF MATTERS

## 4.1 INTRODUCTION

An Access Arrangement must, as a minimum, include the elements described in section 3 of the Code. Section 3 establishes the following requirements:

- **Services Policy** (sections 3.1 and 3.2).

  An Access Arrangement must include a policy on the Services to be offered. The Services Policy must:

  - include a description of one or more Services which are to be offered;
  - where reasonable and practical, allow Prospective Users to obtain a Service that includes only those elements that the User wishes to be included in the Service; and
  - where reasonable and practical, allow Prospective Users to obtain a separate tariff in regard to a separate element of a Service.

- **Reference Tariff and Reference Tariff Policy** (sections 3.3 to 3.5).

  An Access Arrangement must contain one or more Reference Tariffs. A Reference Tariff operates as a benchmark tariff for a specific Service, in effect giving the User a right of access to the specific Service at the Reference Tariff, and giving the Service Provider the right to levy the Reference Tariff for that Service.

- **Terms and Conditions** (section 3.6).

  An Access Arrangement must include the terms and conditions on which the Service Provider will supply each Reference Service.

- **Capacity Management Policy** (sections 3.7 and 3.8).

  An Access Arrangement must state whether the Covered Pipeline is a Contract Carriage Pipeline or a Market Carriage Pipeline.

- **Trading Policy** (sections 3.9 to 3.11).

  An Access Arrangement for a Contract Carriage Pipeline must include a policy on the trading of capacity.

- **Queuing Policy** (sections 3.12 to 3.15).

  An Access Arrangement must include a policy for defining the priority that Prospective Users have to negotiate for specific Capacity (a Queuing Policy).

- **Extensions/Expansions Policy** (section 3.16).

  An Access Arrangement must include a policy setting out a method for determining whether an extension or expansion to the Covered Pipeline/distribution system is or is not to be treated as part of the covered pipeline for the purposes of the Code.

- **Review Date** (sections 3.17 to 3.20).

  An Access Arrangement must include a date on or by which revisions to the Access Arrangement must be submitted and a date on which the revised Access Arrangement is intended to commence.

With the exception of the requirements relating to Reference Tariffs, the compliance of the Access Arrangement with the above requirements of the Code is addressed below. Reference Tariffs are addressed separately in section 5 of this Draft Decision.

## 4.2 SERVICES POLICY

### 4.2.1 Access Code Requirements

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 that 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.

### 4.2.2 Access Arrangement Proposal

A Services Policy is provided in section 6 of the proposed Access Arrangement, which commits Epic Energy to making available a Reference Service to Prospective Users, and negotiating in good faith (subject to operational availability) for the provision of Non-Reference Services to Prospective Users.

**Reference Service**

The Reference Service offered is termed the “Firm Service” and has the following general characteristics:

- The service can involve either forward haul or back haul of gas.
- Receipt of gas must be at one or more Receipt Points in Zone 1 of the pipeline.
- 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.

**Non-Reference Services**

Paragraph 6.1(b) of the proposed Access Arrangement provides a non-exhaustive list of Non-Reference Services, 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 the Regulator 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 by particular month to supplement their contracted Firm Service capacity.
- Peaking Service, which is understood 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 MDQ).
- Metering Information Service.
- Pressure and Temperature Control Service.
- Odorisation Service.
- Co-mingling Service.

No descriptive information is provided in the proposed Access Arrangement on the Metering Information Service, the Pressure and Temperature Control Service, the Odorisation Service or the Co-mingling Service.

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.

### 4.2.3 Submissions from Interested Parties

#### 4.2.3.1 Overview of Submissions

The submissions from interested parties addressed the following issues in respect of the Services Policy and the proposed Reference and Non-Reference Services:

- A requirement that the Access Arrangement provide for a Reference Service that is not materially different than the "T1 Service"[7] established under the *Dampier to Bunbury Natural Gas Pipeline Regulations 1998*;
- Limitations on locations of receipt of gas into the DBNGP under the proposed Reference Service.
- Limitations on capacity that can be contracted for back haul of gas under the Firm Service.
- Provision of other services as Reference or Non-Reference Services.
- The minimum term of contract for the Firm Service.
- Limitations on services intended to be provided by Epic Energy.

The submissions in respect of each of these issues are summarised below together with the Regulator's responses.

[7] In its Submission 8, Epic Energy has indicated that the term "T1 Service" is taken to mean the service and terms and conditions associated with that service for T1 capacity that AlintaGas (as the previous owner of the DBNGP) was required to grant to Users under the *Gas Transmission Regulations 1994*, or as Epic Energy is required to grant at present under the "repealed access scheme" as defined in clause 9(3) of Schedule 3 to the *Gas Pipelines Access (Western Australia) Act 1998*. For purposes of this Draft Decision, the Regulator will use the term "T1 Service" in the same meaning.

#### 4.2.3.2 Provision of a T1-Equivalent Service as a Reference Service

**Submissions**

Several submissions to the Regulator highlighted differences between the proposed Firm Service and the existing "T1 Service", established under *Gas Transmission Regulations 1994* and carried over into the *Dampier to Bunbury Pipeline Regulations 1998*. It was submitted that the Reference Service established by the Access Arrangement should not be materially different than the T1 Service. Epic Energy made submissions to the Regulator responding to these views. These submissions are summarised as follows, with the Regulator's views set out following the whole of the respective summaries.

<u>Differences between the Firm Service and T1 Service</u>

While both the T1 Service and the Firm Service comprise "non-interruptible" (firm) haulage services, several submissions indicated differences between the two services relating to both the scope of services provided under the title of the regulated service, and to the terms and conditions on which the regulated service is provided. The parties making submissions indicating specific differences between the T1 Service and the Firm Service were as follows:

- Worsley Alumina
- CMS Gas Transmission
- AlintaGas (submissions 2 and 3)
- WMC
- Western Power (submissions 1, 2 and 4)
- Wesfarmers Limited
- Treasury/Office of Energy

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 through a Delivery Point charge.
- Provision of seasonal adjustments to contracted MDQ as a Non-Reference Service rather than part of the regulated service.
- Provision of a Park and Loan Service as a Non-Reference Service rather than part of the Reference Service.

Arguments for the Firm Service to be materially the same as the T1 Service

The views put forward in submissions for a Reference Service to be established that is materially the same as the T1 Service and responses from Epic Energy to these views are set out as follows.

1. Development of the T1 Service through a consultative process.

   The view has been put forward in submissions that the T1 Service was developed by an extensive consultation process that:

   - results in a definition of a regulated service that meets the requirements of the majority of Users of the DBNGP;
   - reflects the operational characteristics of the DBNGP; and
   - achieves 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.

   AlintaGas[8] submitted that where there has been a well-developed set of access terms and conditions that has evolved over a number of years through an industry consultation process to set a reasonable balance of risks and costs between the Service Provider and Users, the Regulator, in considering a proposed Reference Service, can properly ask the Service Provider to justify material shifts from the overall balance of risks and costs. AlintaGas and others[9] expressed the view that the proposed Firm Service entails a shifting of risks and costs to Users, whilst increasing costs and charges compared with the existing more balanced position, and that these changes are not welcome, are not fair and reasonable and do not satisfy the objectives of competition policy.

   Epic Energy[10] responded to these submissions indicating that the existence of a defined service under a pre-existing regulatory regime is largely irrelevant to the definition of a Reference Service within the Access Arrangement. Epic Energy argued that such a stance would be inconsistent with the objectives and principles of the Code, in particular, the objective stated in the introduction to the Code to "provide rights of access to natural gas pipelines on conditions that are fair and reasonable for both Service Providers and Users" and the principle stated in the introduction to the Code that the Access Arrangement "is designed to allow the owner or operator of the Covered Pipeline to develop its own tariffs and other terms and conditions under which access will be made available, subject to the requirements of the Code".

   More specifically Epic Energy stated that:

   > The T1 Service was not developed by Epic Energy but was prescribed by government regulation prior to Epic Energy acquiring the DBNGP. That did not evolve out of an open regulatory process such as is being conducted by the Regulator in this case, with its particular emphasis on giving the pipeline operator the ability to run its own business as it wants, within broad parameters. The previous regime was one prescribed by the Government of the day and, at least in the case of the *Gas Transmission Regulations 1994* provided the then pipeline operator no room to move outside of that. It would be a strange result if the complex new national access regime established by the *Gas Pipelines Access (Western Australia) Act 1998* and the Code, and all the changes to the law associated with the introduction of that regime, simply resulted in Epic Energy being bound to offer the same form of service (on the same terms and conditions) prescribed by the previous regulatory regime. Not only

[8] AlintaGas Submission 3.

[9] AlintaGas Submission 3; Western Power Submission 4; North West Shelf Gas.

[10] Epic Energy Submission 8.

would that operate against the spirit of the Code, but would also stifle any opportunity to improve the access regime.

2. The T1 Service is a bundled set of services required by a significant part of the market.

The view was put forward in submissions that a service equivalent to the T1 Service is a "bundled" set of services that would be sought by a significant part of the market for gas transportation in the DBNGP and therefore the Regulator has cause under sections 3.2 and 3.3 of the Code to require a service not materially different to the T1 Service to be included in the Access Arrangement as a Reference Service, and for a Reference Tariff to be established for this service.[11]

AlintaGas[12] has submitted that while the Secondary Market Service has been proposed to take the place of interruptible and overrun services (or applicable components of the T1 Service), this is less than a satisfactory replacement. AlintaGas also submitted that the proposed Secondary Market is inflexible and provides for firm capacity only, whereas the T1 Service permits flexible informal capacity dealing directly between users and incorporates an "AT3 interruptible service" for daily spot capacity (AlintaGas Submission 2). AlintaGas indicated perceived inadequacies of the Secondary Market Service, as follows.[13]

> In Epic Energy's proposed Access Arrangement, the Secondary Market is central to ensuring a user can fully utilise its capacity. AlintaGas submits that the Secondary Market appears to be complex and inflexible. Epic Energy will gain most from an inflexible Secondary Capacity market because users will not be able to sell or buy Secondary Capacity in an effective manner. Some users will have an excess of unused firm capacity whilst other users will have purchased overrun capacity from Epic Energy. In both cases, Epic Energy benefits at the expense of the interests of users.
>
> There is sufficient flexibility within the T1 Service for a user to get access to additional capacity and to sell unused capacity to other users. In the T1 Service, a user has the right to purchase interruptible capacity from Epic Energy that may be available on a day. A user can also buy capacity directly from other users that might have spare contracted capacity, or a user can sell its own spare contracted capacity, assuming another user has a requirement for additional capacity on a day.
>
> This capability to trade capacity is possible because of the right a user has in the T1 Service to deliver gas to Delivery Points at which the user does not have contracted capacity. AlintaGas considers this Delivery Point flexibility to be an important feature of the T1 Service that Epic Energy is not providing within its proposed Firm Service, to the detriment of users. Delivery Point flexibility was limited in the 1994 version of the *Gas Transmission Regulations 1994*. It was introduced in 1997 after extensive development by the Gas Transmission Consultation Committee. For Epic Energy to propose its removal is a significant retrograde step, which seems unreasonable and difficult to justify on technical or operational grounds, given that the facility has been in place for well over two years without apparent difficulty.

Similar views were put forward by Worsley Alumina, indicating that the proposed Secondary Market terms and conditions are restrictive and do not promote the efficient use of the pipeline. Worsley Alumina suggested that the Secondary Market Service provides effectively for a Firm Service for one day, which is 'take or pay' for the day and not interruptible, while under the *Gas Transmission Regulations 1994* the AT3 service was 'pay for what you get' and interruptible. Apache Energy Limited also indicated a concern with a suggested reliance on Secondary Market and Park and Loan Services, in the context of an extremely limited Secondary Market.

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[11] AlintaGas Submissions 2, 3; Western Power Submission 4; Hamersley Iron; Worsley Alumina.

[12] AlintaGas Submissions 2, 3.

[13] AlintaGas Submission 3.

Epic Energy has expressed the view that the proposed Firm Service is similar to, but not the same as, the Firm Service that was available as the T1 Service under the earlier access regime of the *Gas Corporation Act 1994* and the *Gas Transmission Regulations 1994*, and under the transitional access regime of the *Dampier to Bunbury Pipeline Act 1997*, *Dampier to Bunbury Pipeline Regulations 1998* and the Access Manual.[14] Epic Energy has stated 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, in particular:

- provision through the proposed Secondary Market Service for Users to purchase additional capacity on a daily spot market and thereby meeting User requirements that may otherwise be provided by an authorised overrun service or interruptible service;
- provision for additional capacity to be obtained on a seasonal basis through the proposed Seasonal Service provided as a Non-Reference Service; and
- provision of a Park and Loan Service as a Non-Reference Service.

Epic Energy implicitly argues in section 2 of the proposed Access Arrangement Information that the provision of the various services in this way provides greater flexibility for Users in securing the desired services, and altering the purchase of these services from time to time. In a submission subsequent to lodgement of the proposed Access Arrangement, Epic Energy outlines the specific justification for not providing an explicit overrun service, interruptible service or provision for seasonal variation in the contracted capacity (MDQ) under the Firm Service:[15]

> 2.5.1 Epic Energy has not provided an explicit "authorised overrun service" in the DBNGP Access Arrangement. Nevertheless, it has proposed mechanisms which allow Shippers flexibility to overrun their contracted Firm Service capacities in a no less disadvantageous way. In fact it may be regarded as generally a far more beneficial way, being through the proposed secondary market.
>
> 2.5.2 Experience in operating the DBNGP has shown that Shipper requirements for overrun are, in general, not clearly identifiable in advance. In consequence, they are not readily contracted for as a form of service. Most Shipper requirements for overrun arise from changes in circumstances during the day that cannot be accurately predicted in advance. In response to this situation, Epic Energy has provided, through the overrun provisions of the Access Arrangement, a mechanism whereby Shippers can, to the extent that others are not deprived of their contractual entitlements, overrun their contracted Firm Service capacities.
>
> 2.5.3 If a Shipper were able to anticipate a requirement to exceed its contracted Firm Service capacity on or during a day, Epic Energy would expect that Shipper to seek to contract for the additional capacity it required, where short term, through acquiring the necessary capacity on the secondary market. The Shipper should purchase the capacity from a seller on the secondary market, whether another party or Epic Energy, rather than rely on the ability to overrun and risk its use of capacity being interrupted by the pipeline operator so that another Shipper can secure its capacity entitlement.
>
> 2.5.4 The secondary market proposed by Epic Energy is intended to facilitate the short term buying and selling of spare capacity required in these circumstances. In that market, Epic Energy would compete directly with Shippers by offering any spare pipeline capacity it had available on a day. However, it would still be open for such Shipper to buy the capacity outside of the secondary market if it so desired.
>
> 2.5.5 The secondary market, and the proposed non-reference Seasonal Service, would also provide access to capacity that might otherwise be made available as interruptible capacity. Accordingly, an explicit interruptible service has not been included in the proposed DBNGP Access Arrangement.

[14] Epic Energy Submission 3.

[15] Epic Energy Submission 3.

3. Many Users have existing contracts for the T1 Service that will be grandfathered for the purposes of the Access Arrangement, and these Users are likely to seek extensions of contracts, or incremental or replacement capacity on the same terms and conditions as the T1 Service. Consequently, a T1 equivalent service comprises a service likely to be sought by a significant part of the market.[16]
4. 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. The Firm Service therefore does not satisfy the requirement of the Code that the Service Provider offer a standard service that is likely to be required by a significant proportion of Users.[17]
5. 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. Section 6.13 and paragraph 6.18(e) of the Code indicate one of the functions of the concepts of the "Reference Service" and the "Reference Tariff". Both are benchmarks that guide the Arbitrator in deciding what service a Service Provider must offer to a Prospective User, and on what terms and conditions that service will be provided. A Reference Service that favours the interests of the Service Provider has the effect of disadvantaging Prospective Users that chose to negotiate or seek arbitration in relation to access, because the Arbitrator will use the Reference Service as a benchmark.[18]
6. AlintaGas[19] has stated that Epic Energy is legally obliged under the Gas Pipelines Access Act to include in its Access Arrangement a Reference Service materially the same as a T1 Service under the *Gas Transmission Regulations 1994* and the *Dampier to Bunbury Pipeline Regulations 1998*, and to set a Reference Tariff for that service. The view presented by AlintaGas is as follows:

> 13. In March 1998, when AlintaGas sold the DBNGP, the Government expected that there would be reasonably significant falls in DBNGP transmission tariffs. The Government wished to ensure that existing users of the DBNGP had the opportunity to receive the benefit of the expected decline in tariffs, despite having grandfathered transmission contracts.
>
> 14. Section 20 of the *Dampier to Bunbury Pipeline Act 1997* is the statutory device to achieve this objective. It obliges Epic Energy to offer to vary the price under the existing transmission contracts to a price not exceeding the statutory price applicable from time to time for the service provided for in the contract. The "statutory price" is the price that a person could insist on paying if the person were, at the time concerned, entering into a contract for the service concerned. AlintaGas has accepted the offer under section 20 of the *Dampier to Bunbury Pipeline Act 1997*.
>
> 15. Regulation 35(3a) of the *Dampier to Bunbury Pipeline Regulations 1998* provides the "statutory price" up to the date the Access Arrangement is approved, which is a combined full-haul tariff for a 100% load factor T1 Service of $1.00 /GJ, applicable both upstream and downstream of Kwinana Junction.
>
> 16. For section 20 of the *Dampier to Bunbury Pipeline Act 1997* to achieve its objective, the statutory price must also be determinable after the Access Arrangement is approved. AlintaGas submits that section 96 of the *Gas Pipeline Access (Western Australia) Act 1998* accordingly imposes a statutory requirement that Epic Energy's Access Arrangement contain a T1 equivalent Reference Service.
>
> 17. Section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* deals with DBNGP transitional matters. It applies to all access contracts in force immediately before the approval of Epic Energy's Access Arrangement ("existing contracts"), and provides as follows:

[16] AlintaGas Submissions 2, 3; Hamersley Iron.

[17] AlintaGas Submissions 2, 3; Hamersley Iron.

[18] AlintaGas Submission 3.

[19] AlintaGas Submission 2.

*"96 (1) The Code does not affect the continuance or operation of a contract to which this section applies.*

*(2) Nothing in subsection (1) —*

*(a) affects the operation of section 20 of the Dampier to Bunbury Pipeline Act 1997 …."*

18. Section 96(2) of the *Gas Pipelines Access (Western Australia) Act 1998* is clearly intended to preserve the effect of section 20 of the *Dampier to Bunbury Pipeline Act 1997*. However, that result could be achieved by a clause which stated simply that nothing in the Code affects the operation of section 20, so section 96(2) must be meant to do something more. Section 96(2) states that nothing in section 96(1) affects the operation of section 20, i.e. that the operation of section 20 is unaffected by the statement in section 96(1) that the Code does not affect the operation of an existing contract. This means that, to the extent required by section 20, the Code does affect the operation of an existing contract. The only way a Code provision could affect a *Gas Transmission Regulations 1994* contract under section 20 is by specifying a suitable Reference Tariff which is to apply as the "statutory price". Given the content of existing *Gas Transmission Regulations 1994* contracts, this would be a Reference Tariff for a T1 equivalent Reference Service and possibly (although AlintaGas itself does not need one) for a T2-equivalent Reference Service.

19. This conclusion is supported by the State Parliament's second-reading discussion of section 96 on 18 June 1998, when the Minister for Energy said:

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

20. Parliament thus intended *Gas Transmission Regulations 1994* users to be offered "prices contained in the approved Access Arrangement under the Code" under section 20 of the *Dampier to Bunbury Pipeline Act 1997*. Section 96 is there to ensure that the Access Arrangement specifies Reference Tariffs for a T1 equivalent Reference Service, to be picked up by the offer under section 20 of the *Dampier to Bunbury Pipeline Act 1997*.

21. To place any other interpretation on section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* would be to risk an outcome where it is much harder to identify the "statutory price" for *Gas Transmission Regulations 1994* contracts. The Minister's words quoted above make it clear that the Government did not intend section 20 of the *Dampier to Bunbury Pipeline Act 1997* to be hampered in this manner.

Augmenting the National Access Code by the *Gas Pipelines Access (Western Australia) Act 1998*

22. AlintaGas has submitted above that section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* imposes on Epic Energy a statutory obligation to include in its Access Arrangement a Reference Service materially the same as a T1 Service under the *Gas Transmission Regulations 1994* and the *Dampier to Bunbury Pipeline Regulations 1998*, and to set a Reference Tariff for that service.

23. This statutory obligation is in addition to the contents of the Code. AlintaGas submits that there is no policy or legal difficulty with the *Gas Pipelines Access (Western Australia) Act 1998* augmenting the Code in this fashion:

(a) From a policy perspective, section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* has been approved by all other parties to the *Natural Gas Pipelines Access Agreement*.

(b) From a legal perspective, the Gas Pipelines Access Law (being Schedule 1 to the *Gas Pipelines Access (Western Australia) Act 1998* together with the National Access Code in Schedule 2 to the Act) applies in Western Australia by operation of, and hence subject to, the Act. The transitional (and other) provisions of the Act can legitimately augment the operation of the Gas Pipelines Access Law. It is not inconsistent with the Regulator's independence

> under the Act, for the Act to add this transitional requirement to the other requirements of the Code.

Treasury/Office of Energy and Western Power[20] also noted that the Firm Service differs from the T1 Service that is currently used by a significant part of the market under contracts which are grandfathered under section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* as to terms and conditions but, not necessarily, price. Western Power also requested that the Regulator requires an inclusion of a Reference Service and Reference Tariff, which is clearly capable of being identified as the "statutory price" for those *Gas Transmission Regulations 1994* contracts which are amended by the making and accepting of an offer under section 20 of the *Dampier to Bunbury Pipeline Act 1997*.

Epic Energy[21] has submitted that the argument that it is legally obliged to provide a Reference Service that is materially the same as the T1 Service represents a misinterpretation of section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* and section 20 of the *Dampier to Bunbury Pipeline Act 1997*. The counter argument put forward by Epic Energy is as follows:

> The relevant [legislative] provisions are:
>
> – Section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* applies to access contracts in existence immediately before the approval of the Access Arrangement.
>
> – Sub-sections 96(1) and (2)(a) of the *Gas Pipelines Access (Western Australia) Act 1998* provide:
>
> *(1) The Code does not affect the continuance or operation of a contract to which this section applies.*
>
> *(2) Nothing in subsection (1) -*
>
> *(a) affects the operation of section 20 of the Dampier to Bunbury Pipeline Act 1997."*
>
> – Section 20(1) of the *Dampier to Bunbury Pipeline Act 1997* provides:
>
> *"Despite anything to the contrary in a contract under which an assignee assumes the position of the corporation under this Part, the assignee is to offer to vary the price for access to which a person is entitled under the contract to a price not exceeding the statutory price applicable from time to time for the service provided for in the contract."*
>
> – "Statutory price" is defined in section 20(5) of the *Dampier to Bunbury Pipeline Act 1997* to mean "*the price that a person could insist on paying if the person were, at the time concerned, entering into a contract for the service concerned*."
>
> AlintaGas's argument is built upon two propositions: first, that section 96(2) can only be given meaning if section 20 of the *Dampier to Bunbury Pipeline Act 1997* and the Code actually affect the operation of existing contracts; and second, that the only way a Code provision could affect an existing contract is by specifying a suitable Reference Tariff which is to apply as the "statutory price", which would be a Reference Tariff for a T1 equivalent Reference Service and possibly a T2-equivalent Reference Service.
>
> *The first proposition*
>
> This first proposition is wrong because it ignores the obvious point that section 96(2) can clearly be given meaning in so far as it allows for the *possibility* that section 20 of the *Dampier to Bunbury Pipeline Act 1997* and the Code might affect the operation of existing contracts. At the time Parliament enacted section 96(2) there was clearly a possibility that section 20 together with the Code might have the effect, once the Access Arrangement was approved, of requiring Epic Energy to offer a statutory price determined by reference to its Access Arrangement (eg. this would be the case if Epic had decided to include a T1 Reference Service with an accompanying reference tariff in its Access Arrangement).
>
> To emphasise the fact that this is or was a possibility only:

[20] Western Power Submission 4.

[21] Epic Energy Submission 8.

- There is nothing in section 20 itself or the *Gas Pipelines Access (Western Australia) Act 1998* or the Code that expressly requires the Access Arrangement to be structured in a way that ensures that a "statutory price" can be derived from the Access Arrangement once introduced. The definition of "statutory price" is and remains very general in character rather than specifically linked to the Access Arrangement, the Code or otherwise.
- Section 20(1) refers to the "statutory price *applicable from time to time*". This section does not require that a statutory price always exist. If a statutory price does not exist, section 96(2) of the *Gas Pipelines Access (Western Australia) Act 1998* is unlikely to have any operative effect.
- On the other hand, a statutory price may exist but have nothing to do with the Code (for example, if legislation is passed in respect of the grandfathered *Gas Transmission Regulations 1994* contracts which prescribes a statutory price). Again, section 96(2) of the *Gas Pipelines Access (Western Australia) Act 1998* would not have any practical effect.
- A legislative provision is only operative to the extent that the circumstances it relates to exist. It is not the case that a legislative provision must operate at all times and so it is quite possible that at a particular point in time a section may not have any practical effect.

Returning to the key issue. To the extent the possibility existed that the Code and section 20 might operate together to affect existing contracts, section 96(2) was necessary to resolve any potential conflict. That is done by making it clear that if a statutory price became determinable by reference to the Code then the general rule in section 96(1) (ie. that the Code does not affect the operation of existing contracts) would be overridden, because Epic would be obliged to offer the Code statutory price to the existing contract customers despite the terms of their contracts.

It is quite something different to say that the necessary inference arising from section 96(2) is that the Code and section 20 of the *Dampier to Bunbury Pipeline Act 1997* must operate to affect the operation of existing contracts. No such inference arises from the section.

If no such inference arises, then there is no foundation for the next step in the AlintaGas argument. That is to say, if there is no inference that section 20 of the *Dampier to Bunbury Pipeline Act 1997* and the Code must operate to affect existing contracts, it cannot be argued that the Access Arrangement must be structured to ensure that section 20 and the Code affect existing contracts.

*The second proposition*

Even if the first proposition is accepted, the second proposition is wrong.

AlintaGas suggests that the only way a Code provision could affect a *Gas Transmission Regulations 1994* contract under section 20(1) of the *Dampier to Bunbury Pipeline Act 1997* is by specifying a suitable Reference Tariff which is to apply as a "statutory price". AlintaGas says that section 96(2) of the *Gas Pipelines Access (Western Australia) Act 1998* is there to ensure that the Access Arrangement specifies Reference Tariffs for a T1 equivalent Reference Service, which is to be picked up by the offer under section 20 of the *Dampier to Bunbury Pipeline Act 1997*.

If this is its purpose, it is hard to imagine why (given the importance of the point) it was drafted to achieve it in such an oblique way. This is particularly interesting given the Government's original intent as stated in the Information Memorandum provided to potential bidders for the DBNGP. Reference is made on this point to paragraphs 2.8.2 – 2.8.5 of Epic Submission 3.

Leaving this to one side, there *are* other ways the Code could affect existing contracts. A *Gas Transmission Regulations 1994* customer could use the Code (indirectly) to derive a "statutory price" for a T1 Service, even if the Access Arrangement does not include a T1 Reference Service. A *Gas Transmission Regulations 1994* customer (or Epic Energy) could utilise the *Gas Referee Regulations 1995*, together with section 20 of the *Dampier to Bunbury Pipeline Act 1997*, to require the Arbitrator (appointed under the *Gas Pipelines Access (Western Australia) Act 1998*) to determine a statutory price. This would be done by reference to what kind of decision he would make if the customer applied for a T1 Service (being a Non-Reference Service) under section 6 of the Code, and he decided to order Epic Energy to provide such a service after taking into account the requirements of sections 6.15 and 6.18 of the Code.

This being the case, it is wrong to say that the only way a Code provision could affect a *Gas Transmission Regulations 1994* contract is where the Access Arrangement includes a Reference Tariff for a T1 Service.

*Conclusion*

In summary, section 96(2) of the *Gas Pipelines Access (Western Australia) Act 1998* preserves the operation of section 20 of the *Dampier to Bunbury Pipeline Act 1997*, which in turn uses a concept of "statutory price" to the extent (*if any*) that the statutory price is determinable at any time by reference to the Code. Neither section 96(2) nor Epic Energy's statutory obligation under section 20(1) of the *Dampier to Bunbury Pipeline Act 1997* extends so far as to require the Access Arrangement to provide a Reference Service on substantially the same terms as the T1 Service and a Reference Tariff for that service.

Finally, it is worth noting that, based on the definition of "statutory price" in section 20(5) of the *Gas Pipelines Access (Western Australia) Act 1998*, the statutory price is to be determined in respect of "*the service concerned*". To the extent that it is possible for different "services" to be offered under the *Gas Transmission Regulations 1994* contracts, if AlintaGas's interpretation were upheld, Epic Energy would need to include in its Access Arrangement, Reference Services for each of the different contracts that exist so that a statutory price for each of those services could be determined. This cannot have been intended by Parliament.

7. In 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. AlintaGas[22] cited the following clause of Schedule 39 of the asset sale agreement in support of this argument.

   Epic Energy will offer two classes of transportation service:

   – Forward Haul Firm Transportation Service (T1 equivalent Reference Service); and

   – Forward Haul Interruptible Transportation Service (T3 equivalent Reference Service).

   AlintaGas went on to argue that the Regulator is entitled to have regard to Schedule 39 and all the circumstances surrounding the privatisation of the DBNGP when reviewing the proposed Access Arrangement, and that principles under section 2.24 of the Code permit this:

   – the fact that Schedule 39 was the subject of a contractual warranty by Epic Energy to AlintaGas could bring it within paragraph (b) of section 2.24, to the extent that the warranty and the representations in Schedule 39 constitute firm and binding contractual obligations of the Service Provider;

   – the public interest, referred to in paragraph (e) of section 2.24, includes a component of holding the acquirer of a privatised government asset to its representations given at the time of privatisation; and

   – it is in the interests of Users and Prospective Users under paragraph (f) of section 2.24 that a T1 equivalent Reference Service be included in the Access Arrangement, in order to give effect to their offer under section 20 of the *Dampier to Bunbury Pipeline Act 1997*, for convenience of integrating new capacity with their existing contracts, and generally.

   Epic Energy[23] submitted that there was not a representation made to AlintaGas to the effect that a Reference Service materially the same as the T1 Service would be included in the Access Arrangement. The counter argument put forward by Epic Energy is as follows:

   *AlintaGas's submission*

   AlintaGas submits that the Regulator may, in exercising his discretion under section 3 of the Code (discussed below), have regard to the representations made by Epic Energy to AlintaGas at the time of

[22] AlintaGas Submission 2.

[23] Epic Energy Submission 8.

the sale of the DBNGP. Specifically, AlintaGas alleges there was a representation (contained in Schedule 39 of the Asset Sale Agreement) that Epic would include a T1 equivalent Reference Service in its Access Arrangement.

In addition, AlintaGas submits that Epic Energy's proposed ancillary charges and the surcharges embedded in the Firm Service will mean that, contrary to representations made by Epic Energy in Schedule 39, the Firm Service will not constitute a price reduction when compared with the $1.09/GJ tariff imposed for the T1 Service in 1999.

What was not clear from AlintaGas' submission was whether in asserting that Schedule 39 amounted to a representation by Epic Energy to AlintaGas which AlintaGas wished to rely on, AlintaGas accepted that the Reference Service should therefore be consistent with all elements of Schedule 39, including the stated tariff and tariff path. It is now clear from AlintaGas' Submission No. 3 that they are only picking and choosing aspects of Schedule 39, which suit them as, among other things, they suggest that the tariff applying to the DBNGP, should be between $0.79/GJ and $0.84/GJ not as stated in Schedule 39.[24]

AlintaGas also submits that the Regulator is precluded by section 2.25 of the Code from approving an Access Arrangement which would deprive AlintaGas of the benefit of a contractual representation.

*Representations by Epic*

AlintaGas relies on the following statements appearing on page 3 of Schedule 39:

*"Epic will offer two classes of transportation service:*

– *Forward Haul Firm Transportation Service (T1 equivalent service) …"*

and

*"…the proposed Standard Forward Haul Firm Tariff is $1.00/GJ on a combined basis (at 100% load factor) based on a Receipt Point upstream of the inlet side of CS1 and a Delivery Point at Kwinana Junction … The Forward Haul Firm Tariff would represent a substantial discount to the current T1 tariffs…"*

AlintaGas states that the use of the term "T1 equivalent Reference Service", together with the other statements quoted above, amount to a representation by Epic that it would include in its Access Arrangement a Reference Service which was materially equivalent to the T1 Service.

The words "T1 equivalent Reference Service" cannot be read in isolation and must be considered in light of the whole of Schedule 39 of the Asset Sale Agreement. On a complete reading of Schedule 39, it is clear that the words "T1 equivalent service" are used in a broad sense so that "T1 equivalent service" is synonymous with "firm haulage service" which is what the T1 Service was.

It is also clear, on a reading Schedule 39, that the terms and conditions of the service proposed in Schedule 39 are different to those for the T1 Service. For example, on page 3 of Schedule 39, it states that *"Epic will continue to offer the existing T1, T2 and T3 Reference Services during the transition period up to 31 December 1999 to meet the Transitional Access Regime"*. Epic Energy then proceeds to describe its proposed new service. As mentioned above, Schedule 39 makes it quite clear that the tranche methodology will not be used.[25]

Although Schedule 39 of the Asset Sale Agreement contains references to a "T1 equivalent service", the particulars given in Schedule 39 do not correspond with a T1 Service. Examples of the differences between the T1 Service, the Firm Service and the "Schedule 39 service" are:

- Schedule 39 provides that the tranche methodology will *not be used* to define the capacity of the pipeline. This methodology is *fundamental* to the definition of T1 capacity. This alone indicates that the new service would be something that was distinguishable from T1 capacity
- Schedule 39 refers to the Schedule 39 service incorporating provisions which will allow Epic Energy to enhance operating efficiency and utilisation of the asset.[26]

[24] See Section 5.4 – "AlintaGas estimates an appropriate tariff to be about $0.84 per GJ" in AlintaGas Submission No.3. Note also section 5.5 of the same submission, which suggests it should be further reduced.

[25] See page 2 of Schedule 39 under "Tariff Principles".

[26] See page 2 of Schedule 39 under "General Principles and Guidelines".

– Incentives would be put in place to encourage uniform customer conduct on the system (eg unauthorised overruns/imbalances).[27]

Clearly the structure of the tariffs and the tariff path were quite different to those for the T1 Service.

Given these clear indications that the new service would be defined without reference to the tranche methodology and would be priced quite differently (and the fact that no T2 service would be offered), the correct view is that the use of the term "T1 equivalent Reference Service" in Schedule 39 was only intended to mean that this service would be a species of "firm service" (as is "T1") as distinct from a species of "interruptible" service" (such as T3). In that sense, the comparison with T1 was only intended to be a general comparison. This is clear when Schedule 39 is read as a whole.

*Conclusion*

The term "T1 equivalent service" in Schedule 39 of the Asset Sale Agreement is used in a broad sense to mean "firm haulage service". It is clear from the remainder of Schedule 39 that the proposed service under the Schedule is not identical to the T1 Service. Therefore there has not been any misrepresentation by Epic Energy in failing to include a T1 Reference Service in its Access Arrangement.

Epic Energy[28] also expressed the view that the term "service" as defined in the Code should be interpreted broadly, such that it refers to the general or fundamental nature of the service provided, without regard to any differences in the terms and conditions on which that service is provided. If a narrow interpretation (that is, that "service" means exactly the same service taking into account all the terms and conditions that comprise, define and limit the scope of the service) were applied, then each *Gas Transmission Regulations 1994* contract and Access Manual contract would give rise to a different "service", which Epic Energy submits would produce a "bizarre" result.

**Regulator's Response to Submissions**

The Regulator's views on the issues raised in submissions on the question as to whether Epic Energy should provide a T1 equivalent service as a Reference Service are outlined below.

<u>Requirements of the Code</u>

The Regulator firstly considered the requirements of the Code in respect of the Services Policy. Generally, the Code sets broad parameters within which the Services Policy must be designed. Paragraph 3.2(a) of the Code merely requires the inclusion of a description of one or more services that are likely to be sought by a significant part of the market or which the Regulator considers should be included. The Regulator has interpreted paragraph 3.2(a) as requiring a general description of the services offered, rather than a description of detailed terms and conditions of services. Consequently, literal compliance with paragraph 3.2(a) itself is likely to be a relatively minor issue in considering whether a proposed Services Policy meets the requirements of the Code.

Notwithstanding the generality of paragraph 3.2(a), section 2.24 of the Code requires that the Regulator consider the following factors in considering a proposed Services Policy and making a determination as to whether any particular service should be included under the Services Policy:

(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;

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[27] See page 3 of Schedule 39 under "Proposed Transportation Services".

[28] Epic Energy Submission 8.

(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; and

(g) any other matters that the Regulator considers are relevant.

It is on the basis of the factors set out in section 2.24 of the Code that the Regulator has considered the submissions in relation to the issue of whether Epic Energy should provide a Reference Service that is precisely the same as the T1 Service. In particular, the Regulator has given attention to the legitimate business interests of Epic Energy in defining the Reference Service (paragraph 2.24(a)); whether Epic Energy is under a contractual or other obligation to provide a Reference Service that is precisely the same as the T1 Service (paragraph 2.24(b)); and the interests of Users and Prospective Users in the nature of the Reference Service offered (paragraph 2.24(f)). The Regulator's deliberations on these matters are set out below.

<u>Broad or Narrow Interpretation of the Term "Service"</u>

In considering whether Epic Energy is obliged to offer a Reference Service that is precisely the same as the T1 Service, the Regulator examined the decisions of other regulators under the Code in relation to proposed Access Arrangements and the description of services. The Regulator notes that there do not appear to be any decisions by other regulators that examined in any detail whether the term "services" as used in section 3.2 of the Code should be interpreted broadly, such that regard is had only to the fundamental nature of the service offered, or narrowly, such that regard is also had to the elements of and particular terms and conditions upon which a service is offered.

The Australian Competition Tribunal (ACT) did briefly consider the term in its decision regarding coverage under the Code of the Eastern Gas Pipeline.[29] At paragraphs 65 to 70 of its decision, the ACT considered whether the phrase "the Services provided by means of the Pipeline" as used in section 1.9 of the Code had the effect of requiring "services" to be defined in terms of the markets to which particular services are provided, such that a service might be defined as delivery of gas to Sydney, or in terms of a more general point-to-point service, such that a service might be defined as a haulage service consisting of the transport of gas from point A to point B. The ACT concluded the latter interpretation was appropriate. The significance of this to Epic Energy's Services Policy may appear limited. However, it does provide some support for the view that "service" should be interpreted broadly, that is, according to the fundamental nature of the service offered and not to its additional elements or terms and conditions. This is because if "services" is interpreted by reference to a specific market to which the Service is offered, as distinct from any points A and B, then such an interpretation takes into account more than just the basic or fundamental nature of the service.

Additional support for the conclusion that a broad interpretation of the term "service" is appropriate, may lie in paragraphs 3.2(b) and (c) of the Code. These oblige the relevant Service Provider to unbundle its offered services, such that Users may obtain only the elements they wish of a service. If the term "service" were to be interpreted narrowly in this context, then each element could constitute a service in itself. This could produce a situation where there is a plethora of services, which the Code does not appear to contemplate.

[29] Australian Competition Tribunal, Duke Eastern Gas Pipeline Pty Ltd [2001] ACompT 2, 4 May 2001.

Differences Between the Firm Service and the T1 Service

The differences between the Firm Service proposed by Epic Energy and the T1 Service established under the *Dampier to Bunbury Pipeline Regulations 1998* forms the primary basis for most submissions. In the Regulator's view, there are essentially two main differences, as follows:

- For the two services, reliability of the service is defined differently, which translates into different definitions of "firm capacity" of the DBNGP.

  The T1 Service is defined in terms of the "tranche methodology".[30] The tranche methodology provides for a maximum disruption, in aggregate, of two percent of the year (i.e. 7.3 days) but does not place a limit on the amount of capacity disrupted during this time.

  The Firm Service is defined by an alternative methodology whereby reliability of User's reserved capacity is defined as a percentage of the annual reserved capacity that will be available under the service. This methodology provides for a maximum disruption, in aggregate, of one percent of a User's reserved capacity, but does not place a limit on the number of days in the year during which the service may be disrupted.

  As a consequence of the different methodology for defining reliability, the "firm capacity" of the DBNGP is greater under the definition of the Firm Service than under the definition of the T1 Service. Given this, together with the permissible interruption limit of one percent whereby a User would not be liable for the payment of fixed charges if a User's total disruption[31] in a year exceeds one percent of MDQ, the Service Provider appears to be assuming a greater risk than would be the case under the T1 Service.

- The T1 Service comprises a "bundled" set of services whereas the Firm Service comprises only a basic forward haul (and limited back haul) service.

  The T1 Service can be considered as a basic haulage service (i.e. forward haul of up to a fixed contracted maximum daily quantity (MDQ) of gas between a Receipt Point and a Delivery Point) combined with a "seasonal service", an "authorised overrun service" and a "spot service".

  The seasonal service component of the T1 Service arises from specification of a Shipper's contracted capacity on a seasonal basis to take into account seasonal variation in the capacity of the pipeline system to deliver the T1 Service (clause 7 of the schedule to the DBNGP Access Manual). In other words, a Shipper's contracted capacity may be established in a service agreement to be different in winter months than in summer months, corresponding to a greater T1 capacity of the DBNGP in the cooler winter months.

  The authorised overrun service components of the T1 Service arise from clause 33 of the schedule to the DBNGP Access Manual. In instances where an overrun occurs for a Shipper on a particular day, clause 33 provides for that Shipper to be deemed to have purchased from the DBNGP operator an amount of spot capacity equal to the amount of the overrun at a price per gigajoule of the overrun established by trading for spot capacity on the day the overrun occurs.

[30] Regulation 39 of the *Gas Transmission Regulations 1984* and regulation 10 of the *Dampier to Bunbury Pipeline Regulations 1998*.

[31] Excluding a disruption attributable to Force Majeure.

The spot service component of the T1 Service arises from, *inter alia*, clauses 14 to 16 of the DBNGP Access Manual and clauses 101 and 111 of the schedule to the DBNGP Access Manual. The spot service provides for purchase under an access contract of interruptible capacity on a spot (daily) basis. The price paid by the Shipper per gigajoule of spot capacity is determined by a bidding system whereby Shippers nominating for spot capacity submit price bids for that capacity, and the spot capacity is allocated by priority of highest bids.

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. However, Epic Energy has proposed 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 proposed 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. The Regulator considers that by virtue of the Seasonal Service and Secondary Market Service offered by Epic Energy as Non-Reference Services, a similar suite of generic services is available to Users under the proposed Access Arrangement as was available as part of the T1 Service. The principal differences are that under the Firm Service:

- Users must contract separately for increases in contracted capacity on a seasonal basis and negotiate a tariff with Epic Energy for this additional capacity;
- in the event of a User desiring greater capacity for a particular day, that User must purchase capacity through the secondary market service (or from another User outside of the Secondary Market Service) rather than being deemed to have automatically purchased spot capacity in the event that an overrun of contracted capacity occurs for that User; and
- provision is made for Users to purchase spot capacity as firm capacity (via the Secondary Market Service) rather than as interruptible capacity, and the terms and conditions of access to spot capacity are specified separately to the terms and conditions of the contract for reserved firm capacity.

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.

Despite the differences identified above between the T1 Service and the Firm Service, the Regulator considers that to the extent that Epic Energy's Services Policy generally describes the services offered, it provides for the delivery of services that collectively may be regarded as equivalent to the T1 Service.

<u>Obligations to Offer a Strictly T1-Equivalent Services as a Reference Service</u>

A number of the submissions received by the Regulator[32] submitted that a T1 Service should be offered on grounds including the following:

- The T1 Service is likely to be sought by a significant part of the market. No significant part of the market for gas transportation through the DBNGP is likely to seek a service in the form of the proposed Firm Service.

[32] Including AlintaGas Submissions 2, 3; Hamersley Iron.

- Many Users have existing contracts for the T1 Service that will be grandfathered for the purposes of the Access Arrangement, who will seek extensions of contracts or incremental or replacement capacity and will consequently require a T1 Service, and thereby create a demand for such a service.

The Regulator has noted these submissions and the significance of the demand of the persons having made them in considering whether a T1 Service, if offered as a Reference Service, would be likely to be sought by a significant part of the market. The Regulator's views on the matters put forward in submissions are detailed below in relation to:

- a statutory obligation on Epic Energy to provide a service that is precisely the same as the T1 Service;
- a contractual obligation on Epic Energy to provide a service that is precisely the same as the T1 Service; and
- the significance of demand for a service that is precisely the same as the T1 Service.

<u>Statutory Obligation to Offer a T1 Service as a Reference Service</u>

Two arguments have been put forward in submissions to the effect that Epic Energy has a statutory obligation to provide a Reference Service that is precisely the same as the T1 Service:

i. the Firm Service provides an inappropriate benchmark for the Western Australian Gas Disputes Arbitrator; and

ii. Epic Energy is legally obliged under section 96 of the *Gas Pipelines Access (Western Australia) Act* 1998 ("*Gas Pipelines Access (Western Australia) Act 1998*") and section 20 of the *Dampier to Bunbury Pipeline Act 1997* to include in its Access Arrangement a Reference Service materially the same as the T1 Service.

The argument that the proposed Firm Service may provide an inappropriate benchmark for the Western Australian Gas Disputes Arbitrator[33] goes, in part, to whether or not the terms and conditions upon which the Firm Service will be offered unreasonably favour Epic Energy at the expense of Users. This is an issue that comes within section 3.6 of the Code and not section 3.2. Section 3.2 merely requires a description of the service to be offered. In this regard, the Regulator considers that the term "services" as used in the Code should be interpreted broadly. It is the character of the services and not the precise terms and conditions upon which they are offered which is relevant for the purposes of section 3.2 of the Code, taking into account the definition of "services" in section 10.8 of the Code. A consequence of this view is that the terms and conditions upon which services are offered should be considered under section 3.6 and not section 3.2, which the Regulator considers accords with the general structure of section 3 of the Code. General compliance of the Access Contract Terms and Conditions with the Code is discussed in section 4.3 of this Draft Decision.

AlintaGas[34] contended that Epic Energy is legally obliged under section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* and section 20 of the *Dampier to Bunbury Pipeline Act 1997* to include in its Access Arrangement a Reference Service materially the same as the T1 Service. The Regulator considers that the effect of the provisions cited in support of the argument may not be to require Epic Energy to include a Reference Service

[33] See AlintaGas Submission 3.

[34] AlintaGas Submission 2.

that is precisely the same as the T1 Service. This view is based on observations of the Regulator including the following.

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 the service provided for in the contract. The "statutory price" is the price the person could insist on paying if the person were entering into that contract at the present time (for example, the Reference Tariff if the service were a Reference Service). 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*.

Section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* is a transitional provision. It makes it clear that section 20 will continue to operate in respect of existing access contracts notwithstanding any approval of the proposed Access Arrangement. Section 96 is necessary to ensure that any approval of the proposed Access Arrangement may not unintentionally terminate or otherwise affect existing access contracts, except as provided.

A number of observations may be made regarding section 20. Section 20 is not specific about the means by which the statutory price may or must be determinable. It presumes that the statutory price will be specified in such a way that a User will have an enforceable right to pay no more than that price. This may include specification in the relevant service contract between the User and Epic Energy or, more likely, in an instrument upon which persons with an interest may rely, such as an Act of Parliament, Regulations made under an Act (as is currently the case) or in an Access Arrangement. It may potentially also include a situation where the statutory price is not specified in either of these ways but may be derived from such documents (such that the underlying right is not affected).

Section 20 refers to the statutory price "applicable from time to time". This phrase may mean that at all times there will be a statutory price but that price may vary. Alternatively, it may mean that there may or may not be a statutory price and that if there is one, it may vary. The *Dampier to Bunbury Pipeline Regulations 1998* may resolve these differing possible interpretations. Under regulation 35 of the Regulations, maximum prices are specified for various components of T1 and T2 capacity. None are specified for T3 capacity. Regulation 36 provides "there is no statutory price for the purposes of section 20 of the *Dampier to Bunbury Pipeline Act 1997* except for capacity for which a maximum price is fixed by regulation 35". As regulations 35 and 36 (along with the entire *Dampier to Bunbury Pipeline Regulations 1998*) cease to operate once the Access Arrangement is approved, the Regulator favours the second possible interpretation – that is, the phrase "applicable from time to time" means that at any particular time there may or may not be a statutory price and if there is one, it may vary. Accordingly, the Regulator considers that section 20 does not require that a statutory price must exist at all times.

Section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* does not add anything to section 20 of the *Dampier to Bunbury Pipeline Act 1997*. It merely ensures that section 20 may continue to operate, to the extent that it can. The Regulator considers that section 20 does not, by itself, oblige Epic Energy to offer a Reference Service that is precisely the same as the T1 Service. This interpretation implies that section 96 does not oblige Epic Energy to offer such a service with or without the operation of section 20 being taken into account. Since a Reference Service that is precisely the same as the T1 Service is not offered in the proposed Access Arrangement, any obligation to include one is likely to depend on whether or not a significant part of the market would seek such a service (discussed below).

The effect of this would appear to be as follows. If, with the proposed Firm Service as the only Reference Service, it were possible to derive a statutory price for the T1 Service from the Access Arrangement in its present form, then Epic Energy would be required to offer that price to such Users under section 20. Further, if the proposed Firm Service combined with other Non-Reference Services is equivalent to the T1 service, then the Reference Tariff for the Firm Service may be the basis of any price applicable under section 20 of the *Dampier to Bunbury Pipeline Act 1997*.

In view of the above, the Regulator does not consider that Epic Energy is placed under an obligation by section 20 of the *Dampier to Bunbury Pipeline Act 1997* and/or section 96 of the *Gas Pipelines Access (Western Australia) Act 1998* to provide in its Access Arrangement a Reference Service that is precisely the same as the T1 Service.

<u>Contractual Obligation to Provide a T1 Equivalent</u>

It has been argued in submissions that Epic Energy is placed under an obligation to provide a T1 Service as a Reference Service by Schedule 39 of the DBNGP Asset Sale Agreement.

The Regulator has reviewed Schedule 39 to the Asset Sale Agreement by which AlintaGas sold the DBNGP to Epic Energy. Under Schedule 39, Epic Energy states that it will offer a "forward haul firm transportation service (T1 equivalent Reference Service)". However, this is one of two *classes* of services it said it would offer, as distinct from two services *per se*. It may also be contrasted with references to offering the "existing T1, T2 and T3 Services" until 31 December 1999. It is noted that the forward haul firm transportation service described in Schedule 39 differs in a number of important respects from the T1 Service, including discontinuation of use of the tranche methodology for defining pipeline capacity and different tariff determination principles. There is also mention in Schedule 39 of new and existing Shippers "switching" to the Reference Service that will be offered in the Access Arrangement under the Code. The result of this is that Schedule 39 contains identifiable and potentially substantial differences between the "forward haul firm transportation service" described in Schedule 39 and the T1 Service.

It may therefore be reasonable for any person reading Schedule 39 to conclude that the Service being offered under Schedule 39 was not equivalent to the existing T1 Service, notwithstanding the use of the words "T1 equivalent Reference Service". AlintaGas agreed to Schedule 39 by executing the Asset Sale Agreement. Without more, AlintaGas may therefore have agreed to Epic Energy offering a service that would be similar to but not the same as the T1 Service – that is, not offering a service that is precisely the same as the T1 Service. If this is correct, then by offering the Firm Service, Epic Energy may have complied with its obligations under Schedule 39 (if any) and AlintaGas would not be deprived of any right under section 2.25 of the Code. The Regulator considers that the proposed Access Arrangement may accord with this view without Epic Energy offering a Reference service that is precisely the same as the T1 Service.

The Regulator notes that AlintaGas submits Schedule 39 should apply such that a "T1 equivalent Reference Service" should be offered, yet the tariff which it estimates and submits as what it considers to be appropriate is substantially less than and does not accord with the tariff proposed in Schedule 39. If Schedule 39 has the significance which AlintaGas submits it has (that is, to constitute a firm and binding contractual obligation of Epic Energy under paragraph 2.24(b) of the Code and/or a contractual right of AlintaGas under section 2.25 of the Code), then it is conceivable that any requirement to supply a Reference Service precisely the same as the T1 Service at a different tariff (such as that proposed by AlintaGas in section 5.4 of its third submission) may deprive Epic Energy of a right to supply that T1 Reference Service (if it were offered) at the tariff described in Schedule 39, which would be contrary to section 2.25 of the Code. There thus appears to be some contradiction in the view taken by AlintaGas.

In conclusion, the Regulator does not consider that the Asset Sale Agreement places Epic Energy under a contractual obligation to provide a Reference Service under the Access Arrangement that is precisely the same as the T1 Service. As such, the absence in the Access Arrangement of a Reference Service that is precisely the same as the T1 Service would not be contrary to the explicit requirement of section 2.25 of the Code that the Regulator must not approve a proposed 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 (or required to be submitted), other than an Exclusivity Right which arose on or after 30 March 1995.

<u>Obligation to Provide a T1 Service by Virtue of Demand by a Significant Part of the Market</u>

The remaining issue is whether a service precisely the same as the T1 Service should be offered as a Reference Service by virtue of it being likely to be sought by a significant part of the market.

The Regulator notes that a number of submissions from parties who presently have substantial demand for the T1 Service indicate that they would seek the T1 Service if it were offered, and that many parties may wish to seek extensions of existing contracts for the T1 Service. The Regulator accepts the view that there is likely to be some demand for a service with at least the fundamental components of the T1 Service. However, as already noted, there is some substance to Epic Energy's comment that previously no service for firm capacity other than the T1 Service was available, notwithstanding the views submitted by others that the T1 Service was established through an extensive consultative process. On balance, the Regulator has taken the view that the stated demand for the T1 Service only demonstrates demand for a service of the general type of the T1 Service (i.e. a service for firm capacity) rather than a service that is precisely the same as the T1 Service.

Submissions also put forward the view that there is demand for components of the T1 Service that are not included as components of the Firm Service, particularly a seasonal service, authorised overrun and spot-market services. The Regulator has considered whether these individual services should be part of the Firm Service, as follows. The further matter of whether these services should be provided as separate and distinct Reference Services is addressed later (section 4.2.3.5 of this Draft Decision).

The Regulator notes that, historically, there has been limited use of component services of the T1 Service that are in addition to the principal haulage service. Two Users have in the past had a requirement for a seasonal service and contracted under the *Gas Transmission Regulations 1994* for seasonal variation in capacity. Combined use of spot market and authorised overrun services has for the period 1995 to 2000 averaged between approximately three and ten percent of current contracted capacity, with a declining trend in use of these services.[35]

[35] Epic Energy, Dampier to Bunbury Natural Gas Pipeline, Information Request 10: Seasonal Capacities, Use of Overrun, and Spot Market Purchases, 31 January 2001.

With regard to the seasonal service component of the T1 Service, the Regulator has considered Epic Energy's proposed provision of firm capacity that becomes available on a seasonal basis as a separate Non-Reference Service (the Seasonal Service) rather than as part of the proposed Firm Service. The Regulator is of the view that capacity that would be made available under the Seasonal Service is not different from capacity made available under the Firm Service except in that it is only available for part of the year. Consequently, the Regulator considers that there is no substantial reason why the charges applying to transmission of gas under the Seasonal Service should differ from the Reference Tariff established for the Firm Service. Moreover, 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.

In view of these factors, the Regulator considers that the Seasonal Service should be incorporated into the Firm Service. This may be achieved by providing in the Access Arrangement and/or Access Contract Terms and Conditions for a User to be able to contract (as part of the Firm Service) for different MDQ in different months of the year. The effect of incorporating the Seasonal Service into the Firm Service is to provide a service which is substantially equivalent to the T1 Service under the *Dampier to Bunbury Pipeline Regulations 1998* but which provides Epic Energy with an opportunity to develop the services it offers in relation to the DBNGP. The only differences lie in the terms and conditions applicable to each. In the circumstances, the Regulator considers that it would not be appropriate to require Epic Energy to offer a Reference Service that is precisely the same as the T1 Service.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 1

The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to combine seasonal capacity attributable to temperature variations with firm capacity, and to allow Users of the Firm Service to contract for the provision of this combined capacity (as part of the Firm Service) thus allowing for different reserved capacity or MDQ in different months of the year.

In regard to the authorised-overrun and spot-market components of the T1 Service, the Regulator is of the view that Epic Energy has proposed to provide substantially similar services as the Secondary Market Service, with prices for these services being determined in a similar manner as determined under the *Dampier to Bunbury Pipeline Regulations 1998*. Given the similarity between the Access Arrangement proposal and the existing T1 Service, the Regulator does not consider there to be any reason for these services to be part of the proposed Firm Service.

#### 4.2.3.3 Limitation on Locations of Receipt of Gas

**Submissions**

Treasury/Office of Energy noted that there is no Reference Service for forward haul involving receipt of gas in zones other than Zone 1.[36] It was submitted that in the light of the interconnection between the Parmelia Pipeline and the DBNGP, the availability of gas in the Perth Basin, and exploration being undertaken in the South West of the State, the Regulator should consider the need for the proposed Access Arrangement to include Reference Services to cater for these sources of gas.

Similarly, CMS Gas Transmission noted that:

> … the Access Arrangement makes no provision for Producers to enter the DBNGP at any zone other than Zone-1. In addition, it would appear that the Gas Receipt Charge (which is effectively an access charge) would specifically restrict competition by preventing development of services involving part haul on the DBNGP. As leading proponent of gas storage services as well as the development of a second pipeline to deliver gas into the Mid and South-West of the State, we see this omission as further evidence of the fact that greater real market driven competition in gas transmission is needed in Western Australia to encourage regional development and facilitate true Open Access.

**Regulator's Response to Submissions**

The Regulator notes that presently there is no immediate prospect for gas to enter the DBNGP other than in Zone 1. However, there are some prospects for receipt of gas into the DBNGP at locations outside of Zone 1. For example, with minor modification of existing interconnection between the DBNGP and Parmelia Pipeline, the Mondarra gas storage facility could be used for storage of gas delivered from the DBNGP, with gas subsequently injected back into the DBNGP for transportation to Delivery Points. The use of such a facility would provide substantial potential for more effective and efficient use of gas from the North West Shelf, particularly associated gas for which production rates are variable. There is also a potential, although not any imminent prospect, for gas to be delivered to the DBNGP from gas fields in the Perth Basin and the South West of the State. Provision as part of the Firm Service for receipt of gas into the DBNGP at locations other than in the proposed Zone 1 would be consistent with the interests of Users and Prospective Users utilising the Mondarra gas storage facility or sourcing gas from the alternative fields.

In view of these factors and giving consideration to paragraphs 2.24(a) and 2.24(f) of the Code, the Access Arrangement will be required to be amended to provide, as part of the Firm Service, for receipt of gas into the DBNGP at any location on the DBNGP. The Regulator also notes that the amendment of structure of the Reference Tariff is also required so as to accommodate receipt of gas into the pipeline at points on the pipeline other than Zone 1. This is further discussed in section 5.9.4 of this Draft Decision.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 2<br><br>Clause 6 of the proposed Access Arrangement should be amended to make provision as part of the Firm Service for receipt of gas into the DBNGP at any location on the DBNGP. |

[36] Zone 1 of the pipeline being that section of the pipeline upstream of the Compressor Station 2 downstream isolating valve.

#### 4.2.3.4 Limited Capacity for Back Haul of Gas Under the Firm Service

**Submissions**

Concerns were raised in submissions from Treasury/Office of Energy, Apache Energy, Robe River Mining and WMC as to the provisions for the Firm Service to include a back haul service.

Treasury/Office of Energy noted that although the Firm Service proposed in the Access Arrangement can be either forward haul or back haul, the service involves receipt of gas in Zone 1 and thus effectively a Reference Service for back hauling of gas is available only in Zone 1.

Robe River Mining argued that the Reference Service effectively comprises a front-haul-only service in the Pilbara, and this disadvantages Users of gas in the Pilbara.

WMC indicated that the proposed limitation on upstream Delivery Points (section 6.3 of the proposed Access Arrangement) affords Epic "absolute discretion" to restrict back haul deliveries. WMC is of the view that this discretionary power is too wide, and needs to be limited to a degree of restriction that can be shown to be the minimum necessary to ensure safe and reliable pipeline operation.

Apache Energy Limited indicated a view in its submission that a back haul service should be a negotiated Non-Reference Service with a tariff determined as a distance-related charge.

**Regulator's Response to Submissions**

In the Regulator's view, the effect of amending the proposed Access Arrangement to provide for the receipt of gas into the DBNGP in any zone of the pipeline will be to extend the capacity for back haul of gas. Accordingly, the concerns raised in relation to the limitation arising from clause 6.2 of the proposed Access Arrangement will be addressed in the amended Access Arrangement.

In regard to the concerns expressed by WMC in relation to the proposed limitations on upstream Delivery Points (clause 6.3 of the proposed Access Arrangement), the Regulator considers that it is unreasonable that the Access Contract Terms and Conditions should provide for Epic Energy to be able to restrict Upstream Deliveries in the manner proposed. The reason for this is that clause 6.3, as proposed, provides for Epic Energy to restrict Upstream Deliveries even where the lack of sufficient gas to service downstream Delivery Points arises from a failure by the Users of the downstream Delivery Points to deliver sufficient gas into the pipeline.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 3<br><br>Clause 6.3 of the proposed Access Arrangement, relating to back haul of gas under the Firm Service, should be deleted. |

#### 4.2.3.5 Provision of Other Services as Reference or Non-Reference Services

**Submissions**

Submissions on the proposed Access Arrangement noted that the Services Policy has not made allowance for an authorised overrun service or an interruptible service as either Reference Services or Non-Reference Services, and that several services previously offered to Users as part of the T1 Service are now offered as Non-Reference Services.

North West Shelf Gas expressed a concern that there is no proposal to allow authorised overruns, and that this would appear to be aimed at stimulating activity in the proposed Secondary Market for pipeline capacity.

Treasury/Office of Energy requested that the Regulator consider the need for an interruptible service to be offered as a Reference Service:

> Further, Epic Energy has not offered in its Access Arrangement a service similar to the current "interruptible" service, which is also at present used by some Shippers on the DBNGP. It is also worth noting that the existing contracts utilise almost the entire capacity of the pipeline as currently configured. To form a view in relation to section 3.3 of the Code, it is considered that the Regulator should consult with the current and prospective DBNGP Shippers in order to determine if the Firm Service offered by Epic Energy under the proposed Access Arrangement is the single Reference Service likely to be sought by a significant part of the market.

Submissions have expressed the view that interruptible, peaking, seasonal, spot and park-and-loan services may be required by a significant part of the market to accommodate flexible gas transportation requirements, and should therefore be provided as Reference Services.[37] It has also been submitted that the provision of these services as separate services rather than as part of a Reference Service provides a means of maintaining, on face value, the Reference Tariff for the Firm Service at the same level as for the T1 Service, but increasing total revenue receipts through sale of ancillary services as Non-Reference Services.

Western Power and AlintaGas[38] both called for an interruptible service to be included in the Services Policy. In particular, Western Power indicated that it is currently substantially reliant on interruptible capacity. AlintaGas has put forward the view that the Secondary Market Service proposed by Epic Energy does not adequately compensate for the absence of an interruptible service, and contends that Users do not want a Secondary Market that provides Users with firm capacity. Rather, Users would benefit, both in the sale and purchase of capacity, if there were an interruptible service combined with Delivery Point flexibility. AlintaGas understands that interruptible services are commonly available in the United States and Canada.

Western Power[39] submitted that seasonal and daily variation in a User's contracted MDQ should be provided for in Reference Services to take account of variations in demand on weekends and according to seasons as provided for under the *Gas Transmission Regulations 1994* regime.

Worsley Alumina submitted that the Metering Information Service proposed by Epic Energy should be a free service, at least for users in Zone 10. At the boundary of Zones 9 and 10 the liquids are stripped from the gas in the Wesfarmers LPG plant. The gas south of this plant

[37] AlintaGas Submission 3, Treasury/Office of Energy; Robe River Iron Associates; Western Power Submission 4; Worsley Alumina.

[38] Western Power Submission 4, AlintaGas Submission 3.

[39] Western Power Submission 5.

can be “dry” or “wet” depending on the operation of that plant. Because the nature of the gas delivered is variable the information about that gas should be made available as a matter of course. The difference between “wet” and “dry” is significant in many applications and knowledge of this is arguably part of the gas being “fit for purpose”.

**Regulator’s Response to Submissions**

The Regulator notes that Epic Energy has described a number of Non-Reference Services in clause 6.1 of the proposed Access Arrangement, which it states are intended to complement its proposed Firm Service. As discussed in relation to whether a T1 equivalent service should be offered as a Reference Service (section 4.2.3.2 of this Draft Decision), the Regulator will require the Seasonal Service to be made part of the Firm Service, but will not require an authorised overrun service or spot service to be included in the Firm Service.

The Regulator gave attention to the remaining Non-Reference Services included by Epic Energy in the Service Policy, that is, the Park and Loan Service, Peaking Service, Metering Information Service, Pressure and Temperature Control Service, Odorisation Service and Co-Mingling Service. The proposed Access Arrangement documentation, including the Access Arrangement Information, does not provide descriptive information regarding the Non-Reference Services proposed in paragraphs 6.1(b)(i)(A) to (H) of the proposed Access Arrangement, other than that list itself. Descriptions of the Non-Reference Services proposed in paragraphs 6.1(b)(i)(A) to (C) are set out in clause 5 of the Access Guide submitted by Epic Energy together with the proposed Access Arrangement, but not of the remainder. In the Regulator’s opinion the Access Guide does not form part of the Access Arrangement or the Access Arrangement Information, and section 2.6 of the Code requires that a detailed description of all of the Non-Reference Services listed in paragraph 6.1(b)(i) of the proposed Access Arrangement be set out in the Access Arrangement Information.

Accordingly, the following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 4<br><br>The Access Arrangement Information should be amended to include a detailed description of the type contained in clause 5 of the Access Guide for each of the Non-Reference Services proposed in paragraphs 6.1(b)(i)(A) to (H) of the proposed Access Arrangement. |

With the exception of the Metering Information Service, the Regulator does not consider there is due cause at the current time for the listed Non-Reference Services (i.e. the Park and Loan Service, Peaking Service, Metering Information Service, Pressure and Temperature Control Service, Odorisation Service and Co-Mingling Service) to either be included in the scope of the Firm Service, or otherwise provided as Reference Services. The Regulator is of the view that as a result of likely differences in requirements of individual Users for these services (both qualitatively and quantitatively), the services are better offered as Non-Reference Services. As Non-Reference Services the characteristics of the services provided to each User and the terms and conditions and tariff for each of the services would be negotiated as appropriate for the circumstances of each User.

In regard to the Metering Information Service, while the scope of this service is not defined in the proposed Access Arrangement documents, the Regulator notes that 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. However, metering information will be provided as part of the proposed Metering Information Service. The Regulator also notes, however, that the Access Contract Terms and Conditions make provision for imposition of a range of penalties on Users including a nomination surcharge (paragraph 4.4(c)), overrun charge (clause 5.2) and excess imbalance charge (clause 6.4)). The Regulator is of the view that if a User of the Firm Service is potentially liable for these penalty charges, then the User should, as part of the Firm Service, have access to the necessary metering information to assess potential liability for these charges and to take action to avoid such charges.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 5<br><br>The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to include, as part of the Firm Service, the timely provision to Users of metering information necessary to assess potential liabilities for penalty charges and enable Users to take actions to avoid those charges. |

In regard to submissions from Western Power and AlintaGas indicating that an interruptible service should be provided to accommodate seasonal variation in gas demand, the Regulator notes the requirement under this Draft Decision for Epic Energy to amend its Access Arrangement to allow Users to have different reserved capacities (MDQ) for different months of the year (Amendment 1). The Regulator considers that this, in combination with availability of additional capacity on a spot basis through the Secondary Market Service, should accommodate the requirements of these Users. The Regulator also notes that Users have the opportunity to negotiate with Epic Energy for services such as an interruptible service regardless of whether or not such a service is described in the Services Policy of the Access Arrangement.

#### 4.2.3.6 Term of Contract for the Firm Service

**Submissions**

Submissions from the Treasury/Office of Energy and Robe River Mining have put forward the view that the minimum five-year term proposed for the Firm Service (clause 6.2 of the proposed Access Arrangement) may not be reasonable. Robe River Mining indicated that the five-year minimum term is not reflective of the requirements of the gas market in a contestable environment where gas sales contracts can be for as little as one or two years.

**Regulator's Response to Submissions**

The Regulator notes that while the Code does not prohibit a requirement such as that which Epic Energy has proposed, the effect of the proposed minimum term is that the proposed review date for the Access Arrangement (1 January 2005 for the commencement of any revisions) would occur before the expiration of any Access Contracts agreed under the Access Arrangement. This may not disadvantage Shippers under such Access Contracts at the time of any amendment since it is the Access Contract Terms and Conditions as amended from time to time that apply (see the definition of "Access Contact Terms and Conditions" in the proposed Access Arrangement).

However, as indicated below, the proposed minimum contract term is substantially in excess of common practice in the gas transmission and distribution industry.

**Contract duration for firm Reference Services on Australian transmission pipelines and distribution networks**

| Pipeline[40] | Minimum contract duration for firm Reference Services |
|---|---|
| Epic Energy – Moomba to Adelaide Pipeline system | 2 years |
| CMS Gas Transmission – Parmelia Pipeline | 1 year |
| East Australian Pipeline Limited – Moomba to Sydney Pipeline System | 1 year |
| N.T. Gas Pty Limited – Amadeus Basin to Darwin Pipeline | 1 year |
| AGL Pipelines (NSW) Pty Limited – Central West Pipeline | 1 year |
| AlintaGas Networks Pty Limited – Mid-West and South-West Gas Distribution Systems | 1 year |
| Goldfields Gas Transmission Pty Limited – Goldfields Gas Pipeline | 1 year |

In view of common industry practice and in the absence of any apparent reason for longer contract terms for the DBNGP, a minimum contract term of no greater than one year will be required.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 6

The proposed Access Arrangement should be amended to provide for a minimum contract term of no greater than one year for the Firm Service.

#### 4.2.3.7 Limitations on Services Able to be Provided by Epic Energy

**Submissions**

Robe River Mining submitted that the references in paragraph 6.1(b)(ii) of the proposed Access Arrangement; paragraph 2.6 of the Access Arrangement Information; paragraph 2.3(e) of the Access Guide and the Non-Reference Service Request Form (particularly clauses 4 and 6) collectively appear to conflict with section 2.50 of the Code to the effect that nothing (except for the queuing policy) contained in an Access Arrangement (including the description of the Services in the Services Policy) is to limit the services the Service Provider can agree to provide to a User or Prospective User or the terms and conditions a Service Provider can agree with the User or Prospective User.

**Regulator's Response to Submissions**

The sections of the proposed Access Arrangement documents and Access Manual cited by Robe River Mining indicate the services that Epic Energy has indicated that it is prepared to negotiate as Non-Reference Services with Prospective Users.

[40] The contract terms cited for the Moomba to Adelaide Pipeline System, the Amadeus Basin to Darwin Pipeline System and the Goldfields Gas Pipeline are for proposed Access Arrangements yet to receive regulatory approval. The minimum one year contract term for the Goldfields Gas Pipeline.

The Regulator has reviewed these provisions and the proposed Access Arrangement documentation generally, but has not identified any provision that suggests that the list of Non-Reference Services in the proposed Access Arrangement documents and other documents is, or is intended to be, exhaustive. That is, the proposed Access Arrangement makes appropriate provision for a Prospective User to negotiate with Epic Energy for a service other than a service listed in the Access Arrangement. As such, the Regulator does not consider that there is any contravention of section 2.50 of the Code.

### 4.2.4 Additional Considerations of the Regulator

In responding to submissions relating to the proposed Services Policy, the Regulator addressed representations that Epic Energy is under an obligation to provide a Reference Service that is precisely the same as the T1 Service as defined under the *Dampier to Bunbury Pipeline Act 1997* and *Dampier to Bunbury Pipeline Regulations 1998*. The following conclusions were drawn in this regard.

- Epic Energy is not obliged by either statute or by the conditions of sale of the DBNGP to offer a Reference Service that is precisely the same as the T1 Service.
- While there is a demonstrated demand for the T1 Service by virtue of existing contracts for this service, the Regulator has taken the view that this only demonstrates demand for a service of the general type of the T1 Service rather than specifically for a service that is precisely the same as the T1 Service. Noting that paragraph 3.2(a) of the Code only requires a general description of the services to be offered rather than a detailed specification of the terms and conditions of services, the evidence of demand for a service of the same general type as the T1 Service is not due cause to require that Epic Energy provide a Reference Service that is precisely the same as the T1 Service.

In view of the above, the Regulator considers that it is neither necessary nor appropriate to require that Epic Energy provide a Reference Service that is precisely the same as the T1 Service.

The Regulator also considered characteristics of the proposed Firm Service independently of the similarity or otherwise to the T1 Service. In this regard, the Regulator considers that the Firm Service is generally acceptable as the sole Reference Service under the Access Arrangement, subject to the following amendments.

- The proposed (Non-Reference) Seasonal Service should be incorporated into the Firm Service, to be achieved by providing in the Access Arrangement and/or Access Contract Terms and Conditions for a User to be able to contract (as part of the Firm Service) for different capacity (MDQ) in different months of the year.
- The Firm Service should make provision for receipt of gas into the DBNGP at any location on the DBNGP.
- The Firm Service should incorporate a back haul service that is unencumbered by restrictions on upstream deliveries.
- The Firm Service should include the timely provision to Users of metering information necessary to assess potential liabilities for penalty charges and enable Users to take actions to avoid those charges.
- The minimum contract duration for the Firm Service should be no greater than one year.

Also in response to submissions, the Regulator considered the proposed Non-Reference Services described in the Services Policy. Subject to the amendments that the Regulator requires to be made to the proposed Access Arrangement to describe more fully the proposed Non-Reference Services, the Regulator is of the view that the Services Policy proposed by Epic Energy is adequate in respect of the Non-Reference Services. The Regulator notes provision in the Access Arrangement of a list of Non-Reference Services does not preclude Prospective Users from negotiating with Epic Energy for provision of services that are different from the listed Reference Service or Non-Reference Services. This could include services precisely the same as the T1 Service, or services in the nature of interruptible services.

Finally, the Regulator is of the view that the Firm Service when amended in accordance with the requirements of this Draft Decision, and when offered in combination with the Non-Reference Services set out in Epic Energy's proposed Services Policy, is similar to the T1 Service.

## 4.3 TERMS AND CONDITIONS

### 4.3.1 Access Code Requirements

Section 3.6 of the Code requires that an Access Arrangement include the terms and conditions on which the Service Provider will supply each Reference Service. The terms and conditions included must, in the Regulator's opinion, be reasonable.

### 4.3.2 Access Arrangement Proposal

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.

### 4.3.3 Submissions from Interested Parties

Extracts from submissions relating to the Access Contract Terms and Conditions are indicated below together with the Regulator's response to matters raised.

**Ability to Change Terms and Conditions (clauses 10.1 to 10.4 of the proposed Access Arrangement)**

- Treasury/Office of Energy

  Epic Energy may vary certain Access Contract Terms and Conditions without the consent of the Shipper or the Regulator.

  The Regulator may wish to consider whether it is appropriate for Epic Energy to vary any Access Arrangement terms and conditions without the Regulator's consent. It is noted that there is a significant number of important terms and conditions that are proposed to be unilaterally varied by Epic Energy including, but not restricted to, matters such as gas specification, receipt and Delivery Points flexibility, nominations, invoicing and payment, metering, default and termination.

- WMC

  In particular, WMC is opposed to the freedom to alter Terms and Conditions sought by Epic in clause 10.4 of the Access Undertaking submission. Any proposed change to the Terms and Conditions should first be submitted to *Off* GAR for approval before they can be implemented. It is *Off* GAR, rather than the proponent, who is best able to judge whether the proposed changes detract or otherwise from the Reference Services.

- Robe River Mining

  Clause 10.3 of the Access Arrangement allows Epic to vary the Access Contract terms and conditions without the consent of the Shipper or the Regulator except in regard to 12 specified areas. We acknowledge the need for some flexibility on variation of Access Contract terms and conditions to take account of operating experience and change of circumstances, however such variations should not disadvantage in any

> material way the rights (in addition to quantifiable monetary rights) of the Shipper. Clause 10.4 tries to capture part of this principle but it is expressed in too vague and uncertain terms.

The Code provides for particular circumstances in which the Service Provider is required to submit revisions to an Access Arrangement in section 3.17 and sections 2.28 and following of the Code. While section 2.28 provides that the Service Provider may submit revisions at any time when it is not required to do so by the Access Arrangement (which may suggest that the Service Provider has some discretion in whether it may make changes to an Access Arrangement, such as Epic Energy proposes in clauses 10.3 and 10.4), under section 2.33 of the Code a limited review process may apply to what may be considered "minor" changes.

In the Regulator's view, all proposed changes to an Access Arrangement must be submitted for review. This does not, however, preclude a Service Provider and User or Prospective User negotiating different terms and conditions for the provision of a Reference Service, in accordance with section 2.50 of the Code.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 7<br><br>Clauses 10.3 and 10.4 of 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. |
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### Core Haulage Obligation

- AlintaGas Submission 3

> AlintaGas submits that there is a fundamental oversight in Epic Energy's proposed Terms and Conditions, namely that there is no express obligation on Epic Energy to accept gas, and no obligation upon it to deliver gas. These two obligations should form the essence of a haulage contract.
>
> The closest that the proposed Access Arrangement comes to identifying and imposing the core haulage obligations appears to be in section 6.2 of the proposed DBNGP Access Arrangement, which defines the Firm Service. However, a definition of Firm Service, as in section 6.2, as one in which Epic Energy takes receipt of gas and delivers gas to the user, does not impose an obligation on Epic Energy to do either.
>
> Furthermore, the proposed Terms and Conditions do not quantify in any way the user's entitlement to receive gas at a Delivery Point. Under the *Gas Transmission Regulations 1994* and 1998 Regime there are express statements to indicate that in return for each energy quantity of gas delivered into the DBNGP by the user, the user receives a right to draw out an equivalent energy quantity of gas. AlintaGas submits that the absence of any such gigajoule-to-gigajoule link should be rectified.

- Epic Energy Submission 9

> AlintaGas has raised a technical legal point at page 32 of AlintaGas Submission No. 3, that the Access Arrangement contains no express obligation on Epic Energy to accept gas and to deliver gas. Epic Energy believes there are adequate provisions contained in the Access Arrangement to cover that, but would have no objection to a recommendation from the Regulator for such a provision to be included.

While the proposed Access Arrangement does not contain a provision that expressly states that Epic Energy is under an obligation to accept and deliver gas, it does contain provisions such as sub-clause 9.4 of the Access Contract Terms and Conditions that refer to "an obligation to deliver gas". Notwithstanding, the Regulator considers that it is reasonable for the Access Arrangement to expressly impose obligations on the Service Provider to accept and deliver gas, subject to the Access Contract Terms and Conditions including the occurrence of any force majeure event.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 8<br><br>The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to include a provision that expressly states that Epic Energy is under an obligation to accept gas and to deliver gas, subject to the limitations of the terms and conditions that apply to any Access Contract entered into with the Shipper, including the occurrence of any force majeure event. |
|---|

## Gas Quality Specification (Clause 2 of the Access Contract Terms and Conditions)

- Treasury/Office of Energy

  Epic Energy's reference tariff is based on the operating gas quality specification (currently prescribed in the DBNGP Access Manual). Epic Energy also states elsewhere in the Access Arrangement document that if it is contractually able to do so, and with the approval of the Coordinator of Energy, Epic Energy may broaden the gas quality specification.

  The Access Manual (and the relevant provisions in the *Dampier to Bunbury Pipeline Act 1997*) will cease to exist on the day the Access Arrangement is approved by the Regulator. Therefore, the approval of the Coordinator of Energy will no longer be required for broadening of the operating specification under the former regulatory framework. In addition, the broadest specification will cease to exist with the repeal of the *Dampier to Bunbury Gas Pipeline Regulations 1998* (again on the day the Access Arrangement is approved by the Regulator). As a consequence there will be no regulatory control over the DBNGP gas quality specification except as provided for under the Access Arrangement. It should be noted, however, that by virtue of section 109 of the *Gas Corporation (Business Disposal) Act 1999* the Coordinator would be able to recreate the DBNGP gas quality specifications should this be considered necessary. Section 109 amends section 26 of the *Energy Coordination Act 1994* by inserting new sub-sections which empower regulations to be made providing for the Coordinator of Energy determining or approving gas quality specifications, which may apply despite being inconsistent with any contractual provisions.

  It would be reasonable to expect that the broadest specification has been adopted by all post-sale contracts on the DBNGP signed under the *Dampier to Bunbury Pipeline Regulations 1998*. The Regulator would also be aware that AlintaGas has adopted, as part of its proposed Access Arrangement, a gas quality specification consistent with the broadest gas quality specification for the DBNGP. In order to ensure consistency in terms of gas quality across these interconnected pipeline systems, the Regulator may wish to request Epic Energy to reconsider the inclusion of the concept of the broadest specification in its Access Arrangement.

  Given the efforts of Government over the years to put in place a gas quality specification for the DBNGP, which achieves the optimum balance between the interests of the upstream gas industry and the interests of the downstream gas end-users, it may be necessary to implement the above mentioned regulations in the event the specification remains overly restrictive after the expiry of the relevant current contracts. By way of example, the Government has made it clear that, although the current contracts would prevent lifting the restrictions for minimum LPGs before mid-2005, it did not intend to continue to regulate for that restriction which intent was reflected in the "broadest" gas quality specification. It should also be noted that the AGA is working towards the establishment of an Australian Standard, which is expected to set down a specification wider than the one prescribed in the Access Arrangement and based on the current "operating" specification. The recommended AGA specification is, for most of its components, in line with the "broadest" gas quality specification for the DBNGP and for some of its components "wider" than the latter specification.

- CMS Gas Transmission

  While Epic has stated that it may accept out of specification gas, the gas specifications in the proposed Access Arrangement are the same as the currently prevailing (December 1999) DBNGP specifications. A surcharge of A$15/GJ applies to unauthorised out of specification gas.

  The "Broadest Specification" is not referenced in Epic's Access Arrangements and should be explicitly included so as not to inhibit market entrants. We would note however that this specification is only broader in certain regards and is in fact still more restrictive than both the Parmelia and the Australian standard in other regards.

An additional consideration is that the Broadest Specification is currently defined in legislative text which is enmeshed with other legislative documents (the Gas Corporations Act, Gas Transmission Regulations, etc). If these documents are to be superseded then it is not clear to CMS where and to what extent the broader gas specification will be embodied.

- Robe River Mining

  Sub-clause 2.3 of the Access Contract Terms and Conditions permits Epic to accept out-of-specification gas "on terms and conditions acceptable to Epic". These terms and conditions should be reasonable, otherwise the right could be exercised in a discriminatory way.

  Sub-clause 2.4 of the Access Contract Terms and Conditions allows EPIC to vent out-of-specification gas which enters the pipe without Epic's consent. The Shipper must then pay the out-of-specification gas charge of $15/GJ. There should be a requirement for Epic to advise the Shipper before the out-of-specification gas charge is to be incurred.

- North West Shelf Gas (NWSG)

  The gas specification proposed for the DBNGP has a maximum inlet temperature of 50 degrees Celsius. This is not consistent with most of NWSJV's existing grandfathered contracts that specify a maximum of 60 degrees Celsius. Without significant modification to the NWSJV plant at very considerable cost, the NWSJVs will be unable to meet this reduced temperature specification in summer. We request that Epic Energy be required to modify the specification to allow a continuation of the existing temperature limit should NWSG or its customers choose to move to an Access Arrangement based transportation arrangement.

Under sections 7 and 8 of schedule 3 of the *Gas Pipelines Access (Western Australia) Act*, and part 5 and schedule 1 of the *Dampier to Bunbury Pipeline Act 1997* are to be repealed when the Access Arrangement is approved by the Regulator. This effectively repeals the *Dampier to Bunbury Pipeline Regulations 1998*, ends the application of the Access Manual and removes statutory control of the gas quality specification. The Regulator notes, however, that since the gas quality specification set out in the proposed Access Arrangement for the Firm Service is contained in schedule 2 to the Access Contract Terms and Conditions, the effect of repeal of Part 5 and schedule 1 of the *Dampier to Bunbury Pipeline Act 1997* is not that there is no regulatory control over the gas quality specification. Rather, the Regulator will have that role.

The Regulator notes that the gas specification set out in the proposed Access Arrangement is the same as the operating gas quality specification in the current DBNGP Access Manual. However, it is not the "broadest specification" set out in Schedule 1 of the *Dampier to Bunbury Pipeline Regulations 1998*. The Regulator notes that differences are due to, inter alia, the contractual obligations of Epic Energy in respect of the quality of gas delivered to the Wesfarmers LPG plant. These contractual obligations will persist until at least June 2005, during which period the gas quality specification proposed by Epic Energy is considered appropriate. The Regulator considers that after June 2005, there is no reason for Epic Energy to not accept into the pipeline gas that meets the broadest specification currently set out in Schedule 1 of the *Dampier to Bunbury Pipeline Regulations 1998*. The Regulator will therefore require that the proposed Access Arrangement be amended to include a gas quality specification to apply from July 2005, where that gas quality specification is no more restrictive than the broadest specification currently set out in Schedule 1 of the *Dampier to Bunbury Pipeline Regulations 1998*.

Under sub-clause 2.3 of the Access Contract Terms and Conditions, Epic Energy has the discretion to accept out of specification gas on terms and conditions acceptable to it. The Regulator considers those terms and conditions should be capable of being considered reasonable. In addition, it is considered reasonable that in the interests of pipeline integrity, Epic Energy should have reasonable discretion to vent out of specification gas without the need to notify Users.

The following amendments are required before the proposed Access Arrangement will be approved.

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| Amendment 9<br><br>The Access Contract Terms and Conditions should be amended to include a gas quality specification to apply from 1 July 2005, where that gas quality specification is no more restrictive than the broadest specification currently set out in Schedule 1 of the *Dampier to Bunbury Pipeline Regulations 1998*. |

| |
|---|
| Amendment 10<br><br>Sub-clause 2.3 of the Access Contract Terms and Conditions should be amended to provide that the terms and conditions acceptable to Epic Energy on which it may accept out of specification gas must be reasonable. |

In response to the submission from North West Shelf Gas in regard to the maximum inlet temperature for gas entering the DBNGP under the terms and conditions of the Firm Service, the Regulator notes that the maximum inlet temperature proposed by Epic Energy of 50 degrees Celsius is less stringent than the current specification under the *Dampier to Bunbury Pipeline Regulations 1998* that provides for a gas inlet temperature of no greater than 45 degrees Celsius unless otherwise agreed to by the DBNGP owner and the User.[41] Further, the Regulator understands that a maximum inlet temperature of 50 degrees Celsius is consistent with common industry practice and that higher temperatures may adversely affect pipeline integrity. On this basis, and acknowledging that it is open for Users to negotiate alternative arrangements with Epic Energy, the Regulator will not require amendment of the proposed maximum inlet temperature.

The Regulator also notes that the proposed maximum inlet temperature for the Firm Service does not affect pre-existing contractual rights of North West Shelf Gas or any other party.

### Delivery Pressure

- CMS Gas Transmission

  The proposed Access Arrangement does not specify a minimum delivery pressure.

  Minimum delivery pressures should be defined. Open Access requires not just commercial certainty – process considerations require Users to also have technical certainty.

Under schedule 2 of the Access Contract Terms and Conditions, Epic Energy specifies a maximum, but not minimum, gas delivery pressure. The Regulator has received technical advice to the effect that it is neither necessary nor desirable to prescribe a minimum delivery pressure. A User will need to supply gas to the DBNGP at a pressure sufficient for the injection of the gas into the pipeline at the Receipt Point. A minimum delivery pressure is established by the pressure in the pipeline at the Receipt Point.

[41] DBNGP Access Manual clause 148 and Appendix 3.

## Nominations (Clause 4 of the Access Contract Terms and Conditions)

- Treasury/Office of Energy

  The Access Guide indicates that a Shipper may exceed its nominations for a Day at a Delivery Point provided that the Shipper remains within its Delivery Point MDQ.

  This is not explicitly stated in the Terms and Conditions.

- Robe River Mining

  The nomination process is unduly inflexible.

- Western Power Submission 5

  The inability to make renominations during the gas day will limit Shippers' ability to optimise gas deliveries and remain within the 2 percent imbalance tolerance.

  Western Power requests the Regulator to require Epic Energy to amend its proposed Access Arrangement to enable renominations within a gas day.

- Apache Energy Limited

  With regard to the Firm Service terms, the absence of allowance for renominations on a Gas Day concerns us.

- Epic Energy Submission 6

  3.1 At least six submissions to the Regulator have raised as an issue the reduced flexibility that Shippers would have under the nominations arrangements proposed in the Access Arrangement Terms and Conditions.

  3.2 Western Power stated, in its Submission Number 5:

  > *"Gas Transmission Regulations 1994 services allow Shippers to renominate within a gas day, whereas the proposed Firm Service excludes this flexibility. A new nomination penalty of $15/GJ may be imposed in some circumstances under the Firm Service.*
  >
  > *To a significant extent, variations in Western Power's gas usage within a gas day (such as might cause gas consumption to depart from nomination levels) are driven by customer load, and on occasions, by unplanned outages of generation units. Both of which, are factors not within Western Power's immediate control. The imposition of very large nomination penalties is unfair in this circumstance."*

  AlintaGas and Worsley Alumina also raised the issue of reduced flexibility to renominate during the day. Robe River Mining was of the view that the proposed nominations process is unduly inflexible.

  3.4 Epic Energy is puzzled by these assertions. Epic Energy is of the view that the new nominations process proposed for the DBNGP is considerably more flexible than the existing process. Under the scheme of the proposed Access Arrangement, nominations no longer have the importance they have under the current access regime. Under the new scheme, a Shipper is entitled to take, subject to conditions governing relocation of Delivery Point MDQ, up to its MDQ on each day regardless of what they have nominated. Epic Energy has no entitlement to "unnominated" capacity, as it has under the current access regime, where a Shipper is locked into its nomination regardless of its contracted capacity.

  3.5 There are no restrictions placed on renominations during the day, apart from the requirements that:

  - the Shipper's nominations across all Receipt Points on a day do not (subject to a requirement for imbalance correction) exceed the Shipper's MDQ;
  - the Shipper's Delivery Point MDQ at each Delivery Point is not exceeded; and
  - the Shipper's MDQ, not be exceeded.

  If a Shipper anticipates a nomination that would cause its MDQ to be exceeded, it should obtain additional capacity in the secondary market before renominating.

  3.6 Nominations facilitate the efficient operation of a pipeline and Epic Energy requires weekly nominations submitted prior to the start of each week. Epic Energy requires that these nominations (and any daily nominations a Shipper may submit) be made in good faith. However, in imposing this requirement, Epic Energy fully understands that nominations are forecasts, and that circumstances beyond a Shipper's control may cause those forecasts not to be realised. The proposed nominations surcharge is intended to apply only in extreme circumstances where there is a clear breach of the obligation to nominate in good faith. The circumstances that Western Power indicates would cause its gas consumption to vary from nominated levels are not circumstances that Epic Energy would normally consider as justifying a variation notice and the subsequent imposition of a nomination surcharge.

The Regulator has reviewed clause 4 of the Access Contract Terms and Conditions in view of the public submissions made in relation to nominations and arguments put forward by Epic Energy in its submission 6. In doing so, the Regulator addressed two issues: the provisions for re-nominations during a gas day, and the provisions for Users to incur a nominations surcharge.

In regard to re-nominations, the Regulator notes that under the 1998 Access Manual re-nominations during a gas day were possible at 0700, 1200 and 2000 hours. In contrast, clause 4 of the Access Contract Terms and Conditions does not provide for re-nominations during a gas Day for that same Day. While Epic Energy has indicated that this is not to the detriment of Shippers as any Shipper may take delivery of gas up to the MDQ regardless of the nomination, the Regulator notes that differences between nominations and deliveries may attract penalties, and that a Shipper may wish to make a late nomination in order to deliver gas in excess of MDQ. The Regulator therefore considers the lack of provisions for re-nomination to be unduly restrictive, given the penalties that may apply to incorrect nominations and the technical ability for re-nominations to be received during a gas Day without disruption to pipeline operation. Accordingly, the Access Contract Terms and Conditions should be amended to provide for re-nomination during a gas Day.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 11<br><br>Clause 4 of the Access Contract Terms and Conditions should be amended to provide for re-nominations during a gas Day. |

Issues relating to the nominations surcharge are addressed in chapter 6 of this Draft Decision in relation to fees and charges other than Reference Tariffs.

### Overrun – Interruptibility and Liability (Sub-clause 5.3 of the Access Contract Terms and Conditions)

- Treasury/Office of Energy

  Paragraph 5.3(b) provides that if Epic Energy interrupts a Shipper, directly or indirectly, as a result of another Shipper taking overrun, then the second Shipper is liable for all loss or damage (including indirect loss) suffered by Epic Energy or the first Shipper, and the Capacity Charges and Receipt Charges which Epic Energy is required to credit to the first Shipper.

  Three potential concerns with 5.3(b).

  First, this clause should be amended to make clear that it is not breached by any purchase by the Shipper of additional delivery capacity greater than MDQ. On its face, the clause could mean that the Overrun provisions are triggered by the Shipper participating in the secondary market.

  Second, as Epic Energy has absolute discretion to interrupt Overrun and will presumably be in control of the equipment to achieve this, the Regulator should consider whether the Shipper should have any liability at all for Epic Energy's failure to prevent Overrun, particularly without notice or opportunity to correct the Overrun. There is no equivalent liability for imbalance in clause 6.

  Third, the clause purports to make the Shipper liable for loss or damage including indirect loss that Epic Energy suffers as a result of an action by Epic Energy, i.e. Epic Energy interrupting another Shipper as a result of a Shipper taking Overrun. This is at odds with Epic Energy limiting its own liability to exclude indirect loss. It means there is limited incentive for Epic Energy to minimise its indirect losses, despite the fact that it is in control of Interruption.

It is noted that reference in 5.3(b)(ii) to clause 14.1(b) should be to 14.2.

The first issue raised by Treasury/Office of Energy relates to the definitions of "MDQ" and "Delivery Point MDQ" in the Access Contract Terms and Conditions. "MDQ" means the aggregate of a Shipper's Delivery Point MDQs, which in turn means the maximum quantity of gas that the Shipper 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, "overrun" is defined as gas delivered to a Shipper which is in excess of the Shipper's Delivery Point MDQ or, where gas which is delivered to various Delivery Points, the gas in aggregate exceeds the Shipper's MDQ. Where a Shipper acquires additional delivery capacity (through the Secondary Market or otherwise), that will form part of the Shipper's MDQ as defined. Accordingly, the overrun provisions will not be triggered.

The second and third issues raised by Treasury/Office of Energy relate to potential liability of Shippers for losses or damages incurred by Epic Energy from overruns. The submission suggested that such liability may be unreasonable where Shippers are not given notice or opportunity to correct overruns. The Regulator is of the view that there may be practical difficulties in providing timely notice to a Shipper of overrun since overrun relates to a single day and is measured at the end of each day. However, the Regulator is requiring that the proposed Access Arrangement and or Access Contract Terms and Conditions be amended to ensure that Users of the Firm Service are provided with metering information that will enable them to detect potential for overruns and take timely remedial action (Amendment 5).

With regard to the potential for a Shipper to incur a liability arising from an overrun, it is noted that under clause 5.3 of the Access Contract Terms and Conditions, Epic has the discretion to interrupt offending Shippers and provides for the Shipper to assume liability for any loss or damage or costs incurred by Epic as a result of the Shipper taking an Overrun. These provisions may be reasonable in so far as the Shipper has no contractual entitlement to Overrun. It may also be reasonable for the Shipper to bear the costs of operating outside of contract provisions. However, the Regulator considers that the offending Shipper's liability should not be unlimited. Epic Energy and other Shippers should be obliged to take all reasonable steps possible to mitigate their loss that may occur in the event of a Shipper taking an Overrun.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 12<br><br>Paragraph 5.3(b) of the Access Contract Terms and Conditions should be amended such that the offending Shipper's liability is not be 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. |
|---|

**Rights of Epic Energy to Use an Alternative Pipeline (Sub-clause 9.4 of the Access Contract Terms and Conditions)**

- Robe River Mining

  Clause 9.4 of the Access Contract Terms and Conditions allows Epic to satisfy its obligations to deliver gas by using a gas pipeline other than the DBNGP, but still to charge tariffs derived from the capital and operating costs relevant to the DBNGP. If the Regulator is to allow this clause to stand then we request it be amended so that any savings in costs through using an alternate pipeline are passed on to the Shipper.

The intent of the access regime set out in the Code is to provide pipeline Service Providers with incentives to seek alternative and more efficient means of gas transportation. One means of achieving this is to allow Service Providers to capture the benefits of efficiency gains made during an Access Arrangement Period for at least the remainder of that Access Arrangement Period. The benefits of efficiency gains would be shared with Users upon review of the Access Arrangement and Reference Tariffs.

The ability of Epic Energy to capture the benefits of efficiency gains resulting from development of alternative means of gas transportation is, in principle, desirable as it provides an incentive for Epic Energy to seek such efficiencies. As such, the Regulator does not consider it appropriate to seek to have the benefits of these efficiency gains passed on to Users prior to review of the Access Arrangement.

### Notional Delivery Points (Clause 11 of the Access Contract Terms and Conditions)

- Treasury/Office of Energy

  Under sub-clause 11.1 Epic Energy may from time to time determine that there is a Notional Delivery Point between the DBNGP and a gas distribution system.

  It is noted that the clause seems inconsistent with the definition of Notional Delivery Point.

  Under sub-clause 11.5, where gas is delivered to a distribution network (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.

  Given the importance of allowing interconnection, the vagueness of this clause is unacceptable if it means there is any possibility of this clause being used to limit, delay or constrain access between Epic Energy's system and another network. Better explanation of what needs to be "taken into account" may be needed.

- CMS Gas Transmission

  In section 11.5 of the Terms & Conditions relating to Multiple Transmission Systems, Epic specifies that,

  > *"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".*

  This clause is itself vague but it would appear that the intent is to maintain Epic's monopolistic access into the AlintaGas Distribution Network. CMS would argue that the clause should be removed on the basis that the connection of alternate suppliers to a distribution network are of necessity physically separate and should be contractually independent.

The Regulator considers that the reference in sub-clause 11.5 of the Access Contract Terms and Conditions to "arrangements between Epic Energy, that other gas distribution system and the operator of that distribution network" is unclear and does not provide sufficient information to Users or Prospective Users. The Regulator considers it is in the interests of Users and Prospective Users for those arrangements to be clearly described and their effect on the Access Arrangement explained. To the extent that arrangements may change over time as between operators and networks, it should be possible for Prospective Shippers to be notified of the relevant arrangements prior to becoming subject to any contractual obligation that may be affected.

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 13

Sub-clause 11.5 of the Access Contract Terms and Conditions should be amended to clearly describe the meaning of and scope of "arrangements between Epic Energy, that other gas distribution system and the operator of that network".

Amendment 14

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.

The Regulator is aware of recent discussions between Service Providers for gas transmission and distribution services and others concerning the technical and commercial arrangements that are needed to allow for the interconnection between transmission pipelines and the gas distribution network. The Office of Energy is facilitating these discussions with the assistance of O*ff*GAR. Epic Energy may need to take into account the outcomes of these discussions in responding to the above requirements for amendment of the proposed Access Arrangement.

***Metering (Clause 12 of the Access Contract Terms and Conditions)***

- CMS Gas Transmission

  The correction period for meter errors as specified in the proposed Access Arrangement, shall not exceed half of the time elapsed since the last meter verification (Terms & Conditions, sub-clause 12.6).

  It is not clear to CMS why the correction period should be constrained to half the period and why it should not apply for the full period since the last accuracy verification test.

As noted by CMS, 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.

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.

The limitation on liability is considered 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). Accordingly, the limitation should be removed. However, there may be circumstances in which the period of inaccuracy cannot be known or agreed upon. 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.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 15

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.

## Liability (Clause 13 of the Access Contract Terms and Conditions)

- Robe River Mining

  Sub-clause 13.4 of the Access Contract Terms and Conditions makes the Shipper responsible for its and its contractors' personnel and property. However, a reciprocal responsibility to the effect that Epic is responsible for its and its contractors' personnel and property is not included. We submit it should be.

- Treasury/Office of Energy

  Sub-clause 13.1 provides that neither party is liable to the other party under any circumstances for indirect damage howsoever caused. Further, under sub-clause 13.3 Epic Energy is not in any circumstances to be liable to the Shipper for any loss, injury, or damage, arising out of any approval by Epic Energy of any design, location or construction of, or proposed operating or maintenance procedures in relation to, any equipment, apparatus, machine, component, installation, cable, pipe or facility connected to, or adjacent to and associated with, the DBNGP.

  A limitation of liability clause refusing liability for such things as loss of profit is probably acceptable. However, the Regulator should consider whether the definition of Indirect Loss (there seems to be inconsistency between use of "Loss" and "Damage") is overly broad. It would be unacceptable to have Epic Energy effectively avoiding any obligation to actually deliver gas by seeking under this clause to exclude any liability for failure to do so.

  For example, Epic Energy at a minimum might be required to compensate a Shipper for the value of any gas Epic Energy fails to deliver in a day, albeit possibly allowing Epic Energy some opportunity to make up the failure in a subsequent period. The Regulator should also consider whether Epic Energy should compensate a Shipper for loss of profits from the sale of gas that Epic Energy fails to deliver.

  An alternative or possibly complementary approach would be to set performance targets that Epic Energy is required to meet.

  Under paragraph 13.4(a), except to the extent caused by the negligence of Epic Energy, the Shipper is liable for any loss or damage which occurs during the duration of the access contract, in or about, or incidental to activities in or about, any Receipt Point, any Delivery Point, the DBNGP, or any other premises, facilities or places used for the storage, transportation or delivery of gas received from or delivered to the Shipper. Under paragraph 13.4(a), the Shipper indemnifies Epic Energy and any person (except the Shipper) contracting with Epic Energy, against all liabilities and expenses arising from or in connection with any claim, demand, action or proceeding made or brought by any person in respect of or in relation to any injury, death, loss or damage referred to in paragraph 13.4(a).

  This clause may not be acceptable. There is no requirement on Epic Energy to demonstrate any negligence or even involvement on the part of the Shipper before this clause attributes liability to the Shipper for any loss in or about, *inter alia*, the DBNGP. The clause would likely be read down by a court, but it is preferable to draft a more realistic provision. For example, insert a requirement that the Shipper is negligent.

  The clause also purports to confer a benefit on a third party, running foul of the doctrine of privity and clause 33. In (a), Shipper's liability is limited to Epic Energy, and in (b) other persons are purportedly given an indemnity.

- Hamersley Iron

  The proposed Access Contract Terms and Conditions are, in some respects, less favourable than the *Gas Transmission Regulations 1994* or they are not commercially reasonable. In particular, sub-clause 13.4 is more onerous to Shippers than Division 5.5 of the *Gas Transmission Regulations 1994*. The indemnity provided by Shippers is unreasonably broad in that it:

(1) is provided to Epic Energy and all of its contractors;

(2) relates to loss or damage anywhere along the route of the Pipeline;

(3) does not necessarily require the Shipper to be at fault; and

(4) holds the Shipper liable for loss or damage caused by Epic Energy's breach of contract or statutory duty (although liability is reduced where Epic Energy is negligent) and the wilful misconduct of its employees.

Hamersley submits that Shippers will not be able to obtain insurance coverage for this indemnity, as required by clause 23 of the Access Contract, because of the broad nature of the indemnity. It should be narrowed so that the Shipper will indemnify Epic Energy for loss or damage caused by the negligent act or omission of the Shipper.

Clause 13 of the Access Contract Terms and Conditions defines limits on liability for Epic Energy and a user party to an access contract. Submissions on the proposed Access Arrangement expressed concerns with some of the limits on liability.

Sub-clause 13.3 of the Access Contract Terms and Conditions provides for Epic Energy to not be liable to the User for any loss injury or damage arising out of any approval given by Epic Energy for works of a Shipper adjacent to or associated with the DBNGP, notwithstanding that Epic Energy's approval for such works is required under provisions such as sub-clause 12.4. Submissions expressed the view that such a limitation on liability may be unreasonable given the requirements for approval to be obtained. The Regulator considers that the exclusion of liability is reasonable notwithstanding the requirement for Epic Energy's approval in such provisions. This is primarily because, as a practical matter, it may be unreasonable not to allow Epic Energy to reserve a right to approve equipment such as under paragraph 12.4(b) where that equipment will be used with or attached to Epic Energy's property (being the DBNGP). To disallow Epic Energy from excluding liability for loss or damage resulting from approvals may also be unreasonable, since Epic Energy may then be obliged to test and determine for itself whether the User's equipment is safe. That would substantially shift the burden of responsibility for safety (for example) of the equipment, potentially designed, owned and built by the User, to Epic Energy. Effectively, any duty of care owed by the User to third parties regarding that equipment would be shifted to Epic Energy, which the Regulator considers would not be reasonable.

Sub-clause 13.4 of the Access Contract Terms and Condition provides for the User to be liable for loss or damage arising from activities associated with Receipt Points or Delivery Points. Submissions expressed a view that the scope of potential liability may be unreasonably broad. The potential difficulty that submissions identify is that the scope of paragraph 13.4(a) is unreasonably broad, such that liability may relate to the whole of the DBNGP. A Shipper could potentially be liable in circumstances where the Shipper supplies gas for transportation in one section of the pipeline while damage occurs in another. Alternatively, the Shipper may be liable where gas it supplied is held in storage while damage occurs to the pipeline itself. The Regulator considers such liability cannot be considered reasonable under section 3.6 of the Code. Paragraph 13.4(a) should be limited such that liability may only arise where damage occurs as a result of the Shipper's actions.

Further, under paragraph 13.4(b), the Shipper would be required to indemnify Epic Energy and any person contracting with Epic Energy. This conflicts with clause 33 of the Access Contract Terms and Conditions which states that:

No person other than Epic Energy or the Shipper is to obtain any benefit or entitlement under this contract, despite that person being referred to in this contract or belonging to a class of persons which is referred to in this contract.

Enforcement of paragraph 13.4(b) may be difficult, if not impossible, under the general law principle of privity of contract. The Regulator considers that clause 33 of the Access Contract Terms and Conditions should be retained. Accordingly, the reference in paragraph 13.4(b) to “any person contracting with Epic Energy” should be deleted.

The Regulator has also noted some inconsistency between sub-clause 13.4 and clause 28 of the Access Contract Terms and Conditions. The Regulator has observed that under paragraph 28(a) of the Access Contract Terms and Conditions, the User is deemed to own any relevant plant, equipment, pipelines and facilities upstream of a Receipt Point or downstream of a Delivery Point, and Epic Energy is deemed to own all plant, equipment, pipelines and facilities between the Receipt Point and Delivery Point. These provisions provide parameters for determining the scope of the obligations each party has under an Access Contract. However, those parameters are not reflected in sub-clause 13.4, which extends potential liability of the User to, literally, the entire pipeline and all related facilities. The Regulator considers clause 13.4 should be amended to reflect the parameters for which clause 28 of the Access Contract Terms and Conditions provides.

The following amendments are required before the proposed Access Arrangement will be approved.

| Amendment 16 |
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| Paragraph 13.4(a) of the Access Contract Terms and Conditions should be amended to limit the liability of the Shipper to situations where loss or damage occurs and is directly caused by the Shipper’s actions. |

| Amendment 17 |
|---|
| Paragraph 13.4(b) of the Access Contract Terms and Conditions should be amended so as to remove liability of the User to parties other than Epic Energy by deleting the reference to “any person contracting with Epic Energy”. |

| Amendment 18 |
|---|
| Sub-clause 13.4 of the Access Contract Terms and Conditions should be amended such that the liability of each party to an Access Contract is limited to the plant, equipment, pipelines and facilities owned by each and to the sections of the DBNGP between the relevant Receipt and Delivery Points, in accordance with paragraph 28(a) of the Access Contract Terms and Conditions. |

**Curtailment and Interruption (Clause 14 of the Access Contract Terms and Conditions)**

<u>Interruption and Curtailment for Reasons of Prudent Pipeline Operation</u>

- Combustion Air

  We note the incorporation of the National Third Party Access Code for Natural Gas Pipeline Systems (the Code) in Schedule 1 of the Gas Pipelines Access (WA) Act 1998. We also note the prominence of South Australian law as the lead legislation for the adoption of the Code and the access arrangements determined in Victoria, under the Code, Access Arrangements in these states being determined under the respective laws of each jurisdiction.

> Epic Energy's proposed Access Contract Terms and Conditions, at sub-clause 21.1, warrants that it will continuously comply with all safety laws with respect to any of its obligations connected with or arising out of its access contract. The difficulty is that there is no law in Western Australia compelling Epic Energy to an obligation to curtail a gas supply in unsafe, potentially unsafe or non-complying circumstances. This difficulty does not arise in South Australia or Victoria as the legislation in these jurisdictions provides for curtailment of gas supplies: [see Gas Act 1997 (SA) sections 53 and 55].
>
> Whilst the Gas Standards Act 1972 (WA) [the Act] prohibits the commencement of gas supply until the installation meets the requirements; the current legislation relies on the transitional provisions of Schedule 1, Chapter 3 clause 10 of the Gas Distribution Regulations 1996 (WA) for the curtailment of gas supply where safety or compliance issues arise and is an obligation only enforceable upon AlintaGas. This point was made by the Office of Energy to the Joint Standing Committee on Delegated Legislation in September 1999, please note their examination (Report No 45) of the Gas Standards (Gasfitting and Consumer Gas Installations) Regulations 1999 (WA) and the Committee's recommendations for change relating to the obligations of gas suppliers, inspectors and gasfitters.
>
> We note the safety provisions of the Gas Distribution Regulations 1996 (WA) have been incorporated in the proposed AlintaGas Access Arrangements, Clause 134 sub (i) and sub (j), as a condition which may invoke curtailment of gas supply. Whilst an argument suggests that any gas supplier, as a reasonable and prudent person, must curtail gas supply in these circumstances flowing from the gas suppliers obligation under s. 13(1) of the Gas Standards Act 1972 (WA), curtailment is not protected by law in Western Australia.
>
> The Epic Energy proposed Access Arrangement is deficient in respect to the contract terms and conditions relating to safety laws and curtailment conditions according to the National Code and jurisdictional frameworks such as Victoria and South Australia. The National Competition Council (the Council) provides guidance in its issues paper of March 1999, titled "WA Access Regime for Gas Pipeline Services" in determining the application of the Western Australian Government to certify the WA Access Regime. Under issues arising from the Competition Principles Agreement [CPA Clause 6 (3)] the Council (at section 5.2) reinforced the need for a State access regime to conform to the principle of safe use of the facility, by the person seeking access, be assured at an economically feasible cost and, if there is a safety requirement, appropriate regulatory arrangements exist. Obligatory curtailment terms, similar to those enunciated in the AlintaGas Access Arrangement, should be required by the Office of Gas Access Regulation to ensure that such appropriate regulatory arrangements do exist. Curtailment of gas supply for safety reasons must be immediate; should not be fettered by ambiguity or fear of litigation, and until protected by law, should be a condition of all Access Arrangements. A gas supplier or pipeline licensee should not be prejudiced by access arrangements when, as a reasonable and prudent person, curtailment of gas supply is necessary for safety reasons.
>
> …
>
> The cost of maintaining gas safety is of interest and concern to industry and Government. … Gas safety and the cost of gas to market entrants, consumers and operators is threatened by any ambiguity as to the regulatory obligations of gas suppliers and pipeline licensees in regard to the commencement of supply or curtailment of supply.
>
> Such safety obligations must also be referenced in the "Service" along with the relevant regulations, standards and codes; funded by the "Tariff" structures and specifically included in the contract "Terms and Conditions" of all access arrangements in Western Australia. The opportunity to comment on the Access Arrangements and gas safety is appreciated.

The Regulator notes the importance of Epic Energy retaining the ability to curtail or interrupt a Shipper in circumstances where safety is paramount. Under paragraph 14.1(a) of the Access Contract Terms and Conditions, Epic Energy has limited its liability where its acts to curtail or interrupt services for a User in such circumstances. The Regulator considers that this provision is reasonable.

<u>Service Reliability and Permissible Interruption</u>

- WMC

  We suggest in particular that there is scope for specifying the reliability levels associated with "Firm Service".

- AlintaGas Submission 3

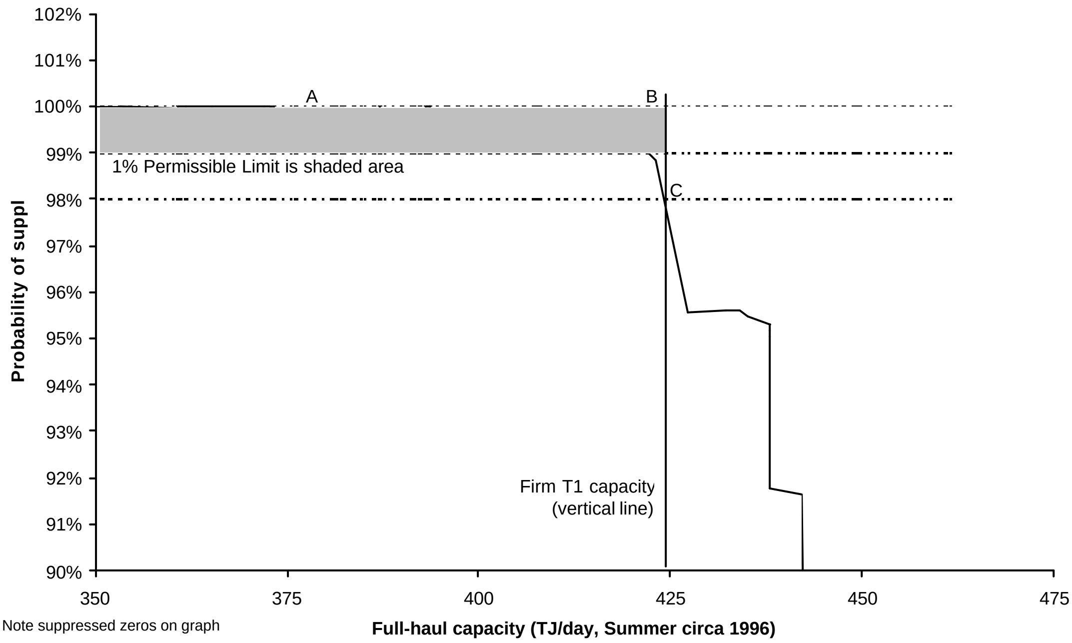
  The Permissible Limit is Excessive

Epic Energy is proposing a permissible limit for interruption of supply of one percent of total contracted capacity during a year. This excludes periods of force majeure. AlintaGas submits that the one percent permissible limit is excessive and inappropriate.

The graph [in Alintagas's Submission 3] shows the probability of supply for full-haul summer capacity on the DBNGP as the pipeline was configured around the summer of 1996. The data is from a report by Tenneco Energy International (now Epic Energy) in November 1996, titled "*A Study of the Dampier to Bunbury Natural Gas Pipeline*" (the "Tenneco Report"). The graph is a conservative one, since it shows the probability of supply without the implementation of recommendations in the Tenneco Report designed to improve the reliability of the DBNGP. AlintaGas does not have access to more up-to-date information.

The rectangular shaded area in the graph shows capacity that Epic Energy proposes may be curtailed as part of the one percent permissible limit. As the graph shows, a substantial portion of the capacity that may be curtailed can be expected to be available.

In comparison, Epic Energy's curtailment rights in the existing T1 Service are based on a reliability of supply of 98%. AlintaGas is confident that, under the *Gas Transmission Regulations 1994*, the total quantity of capacity curtailed will be limited to the area bounded by points A, B and C in the above graph. This provides for an overall reliability of supply above 99.9%. To AlintaGas's knowledge, the curtailment provision has not been required since the *Gas Transmission Regulations 1994* came into effect at the beginning of 1995.




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

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

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

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

Paragraph 14.1 of the Access Contract Terms and Conditions states that Epic Energy may curtail or interrupt the User without liability to the User 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.

The permissible limit relates to the definitions of the Firm Service and Firm Service capacity. The Regulator notes that the methodology used by Epic Energy to define firm capacity (refer to section 4.2.3.2 of this Draft Decision) is technically rigorous and the designation of the permissible limit is not greatly different from Epic Energy's current contractual commitments for service reliability. Further, the Regulator notes that under a permissible limit of one percent, whereby a User would not be liable for the payment of fixed charges if a User's total disruption in a year exceeds one percent of MDQ, the Service Provider appears to be assuming a greater risk than would be the case under the T1 Service. On this basis, the Regulator considers that the definitions of "firm capacity" and the "permissible limit" are reasonable.

In relation to the submission from AlintaGas, the Regulator has noted that 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 in such circumstances. The Regulator considers that it is reasonable that clause 14 should be amended to provide for the prior notification of Shippers in such circumstances, giving at least 30 days notice.

As an additional matter, the Regulator also notes that paragraph 14.2(b) refers to the "Receipt Charge". Sub-clause 5.3 also uses this term. 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 (which is defined), then the latter term used instead.

The following amendments are required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 19<br><br>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 20<br><br>The proposed Access Arrangement documents should be amended to include a definition of the term "Receipt Charge" or, alternatively, the term "Gas Receipt Charge" may be used instead if that term, as defined in the Access Contract Terms and Conditions, was intended to be used. |

### Force Majeure (Clause 15 of the Access Contract Terms and Conditions)

- Robe River Mining

  Clause 15 of the Contract Terms and Conditions and the definition of "force majeure" excludes "strikes or industrial disputes" from force majeure events such that a Shipper will remain liable for all of its obligations even if its plant is shut down due to strikes or industrial disputes. We submit this is quite unconventional within the industry and unreasonable and request that it be amended.

- Hamersley Iron

  The proposed Access Contract Terms and Conditions are, in some respects, less favourable than the *Gas Transmission Regulations 1994* or they are not commercially reasonable. In particular, under paragraph 15(d), a Shipper is not relieved from paying Capacity Charges by the occurrence of an event of Force Majeure, despite not receiving transmission services, even if the Force Majeure is claimed by Epic Energy. Hamersley submits that this is not commercially reasonable as it means that the Shipper bears all of the risk of Force Majeure under the Access Contract. In accordance with normal gas industry practice, the Shipper should get relief from the payment of Capacity Charges when Epic Energy claims Force Majeure so that there is a proper sharing of this risk between the parties to the Access Contract.

The Access Contract Terms and Conditions defines force majeure by exception:

> "Force Majeure" means any even or circumstance not within the control of a Party and which by the exercise of due diligence, that Party is not able to prevent or overcome.
>
> The following will not constitute (directly or indirectly) 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.

The Regulator considers that under clause 15 and the definition in sub-clause 1.1 of "force majeure" in the Access Contract Terms and Conditions, the scope of events that may constitute force majeure is unacceptably broad. It is considered that the definition of "force majeure" should be amended to specify particular events that will constitute force majeure rather than specifying events that will not.

The Regulator notes that it is common practice for the definition of force majeure events to include disruption of pipeline services as a result of industrial action.[42] On this basis, the Regulator considers that it is reasonable for the same to apply in respect of the DBNGP.

Paragraph 15(d) of the Access Contract terms and Conditions states that:

> The Shipper is not relieved of its obligation to pay Capacity Charges by the occurrence of an event of Force Majeure (whether claimed by Epic Energy or the Shipper).

The Regulator considers this provision to be unreasonable and considers a more reasonable arrangement is 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. Paragraph 15(d) should be amended to oblige Epic Energy to waive applicable Capacity Charges where it claims force majeure has occurred. Words to the effect of "except

[42] Force majeure explicitly includes events of industrial action in the AlintaGas Access Arrangement for the Mid-West and South-West Distribution Systems, CMS Gas Transmission Access Arrangement for the Parmelia Pipeline, Eastern Australian Pipeline Limited Access Arrangement for the Moomba to Sydney Pipeline.

to the extent that Epic Energy fails to provide the contracted service" should be inserted at the end of paragraph 15(d).

The following amendments are required before the proposed Access Arrangement will be approved.

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| Amendment 21<br><br>The definition of "force majeure" in sub-clause 1.1 of the Access Contract Terms and Conditions should be amended to specify particular events that will constitute force majeure, including industrial action. |

| |
|---|
| Amendment 22<br><br>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, to the extent that it fails to provide the Service that is the subject of the Access Contract. |

**Assignment (Clause 19 of the Access Contract Terms and Conditions)**

- Western Power Submission 5

  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.

Clause 19 of the Access Contract Terms and Conditions provides for assignment of rights under an access contract by either Epic Energy or the relevant User. Sub-clause 19.2 provides for a Shipper 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.

The Code deals with assignment by Users only in sections 3.9 to 3.11, in relation to the Trading Policy. Clause 19 of the Access Contract Terms and Conditions complies with those sections of the Code (refer to section 4.5 of this Draft Decision). On this basis, the Regulator considers that clause 19 is reasonable.

**Representations and Warranties (Clause 21 of the Access Contract Terms and Conditions)**

- Robe River Mining

  Sub-clause 21.3 allows Epic to seek confirmation from time to time that the Shipper is in a position to meet its obligations under an Access Contract. Under sub-clause 21.4 if Epic is not so satisfied (and no reasonableness test is specified) then the Shipper must provide security for those obligations to Epic's reasonable satisfaction. A failure to provide, or inability to provide, the financial security amounts to an Event of Default allowing Epic to suspend the Service and/or terminate the Access Contract (see sub-clause 17.2). We submit these provisions are susceptible to abuse and could be used to preclude continuing access to a Service by a Shipper and request their amendment.

The Regulator considers that under sub-clause 21.4 of the Access Contract Terms and Conditions, there is some potential for abuse and use of it by Epic Energy to preclude continuing access to a service by a Shipper, by requiring security that may be unreasonable when considered objectively. The Regulator considers that sub-clause 21.4 should be amended to remove the potential for any such conduct, by amending the second part of sub-clause 21.4 to read "… and the Shipper shall provide such security as may objectively be considered reasonably necessary to secure those obligations".

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 23<br><br>Sub-clause 21.4 of the Access Contract Terms and Conditions should be amended to read "If Epic Energy is not satisfied that the Shipper is in a position to meet or continue to meet its obligations under an Access Contract, Epic Energy may require and the Shipper shall provide such security as may objectively be considered reasonably necessary to secure those obligations". |

### 4.3.4 Additional Considerations of the Regulator

The Regulator had concerns in relation to several provisions of the Access Contract Terms and Conditions other than those addressed by submissions. These concerns are discussed below.

**Interpretation (Clause 1 of the Access Contract Terms and Conditions)**

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. It appears sub-clause 18.2 is in fact the relevant provision. If so, this reference should be amended accordingly.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 24<br><br>The definition of "independent expert" in sub-clause 1.1 of the Access Contract Terms and Conditions should be amended to refer to sub-clause 18.2 of the Access Contract Terms and Conditions and not sub-clause 16.2, which appears to have been referenced unintentionally. |

**Receipt Points and Delivery Points (Clause 3 of the Access Contract Terms and Conditions)**

Sub-clause 3.6 of the Access Contract Terms and Conditions makes provision for allocation of gas received into the DBNGP at Receipt Points. Under paragraphs 3.6(b) and (c), where more than one Shipper supplies gas to Epic Energy at a single Receipt Point, each Shipper 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 Shipper to Epic Energy by 0830 hours on the following day.

To assume that no gas has been delivered where written confirmation of supply of gas has not been received in respect of Receipt Points used by more than one Shipper is considered by the Regulator to be unreasonable in a situation where it is known that gas has been delivered to that Receipt Point and the total amount of that gas is known.

The approach proposed by Epic Energy in respect of Receipt Points contrasts with paragraphs 3.7(b) and (c), relating to situations in which more than one Shipper 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.

The Regulator considers paragraphs 3.6(b) and 3.6(c) are unreasonably harsh and that sub-clause 3.6 should be amended to be consistent with sub-clause 3.7.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 25<br><br>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 and for proportional allocation by Epic Energy of gas supplied to a Delivery Point in the absence of any agreement or due notification, consistent with sub-clause 3.7. |

**Charges (Clause 16 of the Access Contract Terms and Conditions)**

Under sub-clause 16.4 of the Access Contract Terms and Conditions, Epic Energy may apply to the Regulator for an adjustment of the charges if there is a change in the regulatory environment. Under sections 2.28 and following and 3.17 of the Code, the Regulator considers that charges and tariffs may only be changed where revisions to the Access Arrangement are submitted for review. While sub-clause 16.4 does not state that Epic Energy will not submit revisions for review in accordance with those provisions of the Code, such a review would in fact be required. To assist Users and Prospective Users in applying and understanding the Access Arrangement, sub-clause 16.4 should be amended to refer to relevant provisions of the Code relating to review of the Reference Tariff.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 26<br><br>Sub-clause 16.4 of the Access Contract Terms and Conditions is required to be amended to make it clear that any adjustment of Charges will be submitted for review in accordance with the provisions of the Code relating to review of an Access Arrangement. |

**Default and Termination (Clause 17 of the Access Contract Terms and Conditions)**

Under sub-clause 17.1 of the Access Contract Terms and Conditions, an event of default is deemed to occur in certain circumstances. 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 Shipper. The Regulator considers that the precise date should be identified.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 27<br><br>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. |

**Metering Requirements (Schedule 3 of the Access Contract Terms and Conditions)**

In paragraphs 5(a) and (d) of schedule 3 of the Access Contract Terms and Conditions, reference is made 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.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 28<br><br>Paragraphs 5(a) and (d) of schedule 3 of the Access Contract Terms and Conditions should be amended to refer to sub-clauses 12.5 and 12.6 of the Access Contract Terms and Conditions as appropriate and not sub-clauses 11.5 and 11.6, which appear to have been referenced unintentionally. |

## 4.4 CAPACITY MANAGEMENT POLICY

### 4.4.1 Access Code Requirements

Section 3.7 of the Code requires that an Access Arrangement include a statement (a Capacity Management Policy) that the Covered Pipeline is either:

(a) a Contract Carriage Pipeline; or

(b) a Market Carriage Pipeline.

Contract Carriage is a system of managing third party access whereby:

(a) the Service Provider normally manages its ability to provide services primarily by requiring Users to use no more than the quantity of service specified in a contract;

(b) Users normally are required to enter into a contract that specifies a quantity of service;

(c) charges for use of a service normally are based at least in part upon the quantity of service specified in a contract; and

(d) a User normally has the right to trade its right to obtain a service to another User.

Market Carriage is a system of managing third party access whereby:

(a) the Service Provider does not normally manage its ability to provide services primarily by requiring Users to use no more than the quantity of service specified in a contract;

(b) Users are not normally required to enter into a contract that specifies a quantity of service;

(c) charges for use of services are normally based on actual usage of services; and

(d) a User does not normally have the right to trade its right to obtain a service to another User.

Section 3.8 of the Code requires that the 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 Regulator permitting the Covered Pipeline to be a Market Carriage Pipeline.

#### 4.4.2 Access Arrangement Proposal

In section 14 of the Access Arrangement Epic Energy propose to manage the DBNGP as a Contract Carriage Pipeline.

#### 4.4.3 Submissions from Interested Parties

- WMC

  WMC supports the operation of the DBNGP system as a “contract carriage” pipeline as defined in the Code.

#### 4.4.4 Additional Considerations of the Regulator

The Regulator recognises that the Code requires no more than a statement in the Access Arrangement that a Covered Pipeline 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, it is considered that the requirements of the Code are met.

### 4.5 TRADING POLICY

#### 4.5.1 Access Code Requirements

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).

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.

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.

### 4.5.2 Access Arrangement Proposal

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.

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 Users 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.

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 at present considered by the Regulator to comprise part of the proposed Access Arrangement.[43]

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.

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.

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.[44]

### 4.5.3 Submissions from Interested Parties

**Relocation of Capacity Across Delivery Points (Sub-clause 3.3 of the Access Contract Terms and Conditions)**

- Western Power Submission 5

  Relocation of capacity between Delivery Points under the Epic Energy proposal, is more restrictive than the current *Gas Transmission Regulations 1994*/*Dampier to Bunbury Pipeline Regulations 1998* position, and therefore, likely to be substantially more expensive for Shippers using the proposed Firm Service arrangements for transfer of capacity between zones.

  This limits Shippers' ability to defray the cost of temporarily unneeded capacity, for example, during planned maintenance periods. On the other hand, it allows Epic Energy to sell more capacity.

  Western Power asks the Regulator to ensure that the costs associated with capacity relocations under the proposed Access Arrangement are reasonable and are not factors that may constrain Shippers ability to transfer capacity between Delivery Points.

- AlintaGas Submission 3

  Epic Energy has not proposed the inclusion of a long-term capacity relocation mechanism, such as was available to Shippers under the *Gas Transmission Regulations 1994* and the 1998 Regime. Section 3.3 of Epic Energy's proposed Terms and Conditions refer to the relocation of Delivery Point MDQ on a "Spot Basis". The definition of "Spot Basis" refers to relocation to another Delivery Point for no longer than a day. Similarly, at section 3.5 of the proposed Terms and Conditions, "Receipt Point Flexibility" is dealt with on a daily basis.

[43] 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.

[44] Note that this Draft Decision requires that the Access Arrangement be amended to allow for gas receipt into the pipeline in any pipeline zone (Amendment 2).

> Long-term relocation of capacity is an important requirement for users to defray risk in the gas sales market. It is particularly important for smaller users, users with one or only a few Delivery Points, and users without a diversified load. However, it is also a significant market risk issue for a larger user such as AlintaGas, who supplies a number of major end-gas users directly from the DBNGP. Long-term relocation of capacity is a measure, short of relinquishment, by which a user can deal with loss of a gas sales customer. If a gas consumer supplied from a particular outlet point ceases using gas, the user is left with stranded capacity. AlintaGas submits that this is inappropriate and not economically efficient.
>
> Similarly, Epic Energy's proposed Access Arrangement does not include any capacity relinquishment mechanisms. The *Gas Transmission Regulations 1994* and the 1998 Regime contained a relinquishment mechanism which preserved considerable flexibility and commercial independence for the DBNGP operator but which nonetheless provided an avenue for users to release capacity left stranded by loss of particular gas customers or market shrinkage.
>
> The omission of these two mechanisms from the proposed Access Arrangement shifts further risk onto users, and also presents Epic Energy with an opportunity for windfall gains. If a user's capacity is left stranded at a Delivery Point because the gas consumer has shifted to another supplier, and the user is unable to relocate or relinquish the capacity, Epic Energy can effectively sell the same capacity to the new user while continuing to receive 95% of the headline tariff from the original user. AlintaGas submits that is economically inefficient and not fair and reasonable.

- Apache Energy Limited

  The Firm Service has a more restrictive regime for relocation of Delivery Points than the T1 Service.

Epic Energy responded in some detail to the submission by AlintaGas in relation to reallocation of capacity across Delivery Points.[45] Epic Energy considers that the proposed Access Arrangement makes similar provision for reallocation of capacity across Delivery Points on a spot basis as the current Access Manual – that is, rights are subject to the contractual rights of other parties:

> Epic Energy still maintains that the Access Arrangement provisions for upstream relocation are more flexible. By putting in the ability to curtail if a Shipper wishes to exercise its entitlements at a Delivery Point (see paragraph 3.3(d)) a Shipper without capacity at that Delivery Point is given greater flexibility and ability to relocate capacity at such points where it does not have contracted capacity. The only reason the Access Arrangement contains a provision requiring Epic Energy's agreement if the capacity is to be taken downstream is because it cannot be guaranteed the capacity will be there in the pipeline to transport the gas. This is particularly the case downstream of Kwinana Junction. The requirement in paragraph 3.3(c) in essence is no different from paragraph 111(5)(a) of the Schedule to the Access Manual.

In relation to long-term re-allocation of capacity across Delivery Points, Epic Energy indicated that no provision is made for this in the proposed Access Arrangement, but could be negotiated with Epic Energy:

> In each case the agreement of Epic Energy is required. Under the Access Arrangement, Epic Energy continues to have the ability to agree anything with the Shipper at any time and can agree to vary the Access Contract to reflect either of these matters. The fact that a prescriptive regime is not provided does not hinder this ability and in fact provides greater flexibility for the Shipper and Epic Energy to adopt an appropriate solution. Epic Energy does not believe that Shippers are in any way disadvantaged under the Access Arrangement in these areas.

The Regulator notes that under paragraph 3.3(a) of the Access Contract Terms and Conditions, a Shipper may elect to relocate any part of its Delivery Point MDQ upstream of the contracted Delivery Point on a spot basis, i.e. for a period of no longer than one day. Clause 3.3 does not provide for any upstream relocation on a non-spot basis.

Under paragraph 3.10(c) of the Code, Users should be able to make such a reallocation subject to providing notice to the Service Provider and subject to the Service Provider not withholding its consent to the relocation on reasonable commercial or technical grounds.

[45] Epic Energy Submission 9.

Accordingly, the Access Contract Terms and Conditions should be amended to make provision for longer-term changes in Receipt Points and Delivery Points. Further, clause 11.2 of the proposed Access Arrangement (Trading Policy) should also make provision for changes in Receipt Points and Delivery Points, such that the ability to make such changes applies to Services generally rather than just Reference Services.

In relation to long-term re-allocation of capacity, AlintaGas also indicated concern as to the absence of provision in the Access Contract Terms and Conditions for a User to relinquish contracted capacity. The Regulator acknowledges 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. However, the Regulator notes that under the Trading Policy a User has rights to transfer capacity to other Users either on a temporary or permanent basis and there limit the risk of financial exposure. The Regulator considers 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.

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 29

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 over 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 30

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 paragraph 3.10(c) of the Code.

**Capacity Trading**

- Robe River Mining

  There will be limited scope for trading Capacity in the Pilbara Region (Zone 1(a)) as there are only two existing actual/potential Shippers with actual or economically proximate Receipt Points within that Zone.

This submission appears to be an observation on current usage of the DBNGP rather than a comment on Epic Energy's Trading Policy per se. That is, the demand for, and ability to, trade pipeline capacity between Users in the Pilbara regions is currently restricted by the small number of Receipt Points in this region. The Regulator considers that the proposed Access Arrangement makes sufficient provision for trading of capacity in the Pilbara region should parties ever wish to engage in such a transaction. The Regulator therefore does not consider any amendment of the proposed Access Arrangement is required, at this time, to address this matter.

## Description and Rules of the Secondary Market Service

- WMC

  The proponent should be required to make a revised set of Secondary Market Rules publicly available for review prior to the Access Undertaking being accepted by O*ff*GAR. In addition, any proposed change to the Secondary Market Rules should first be submitted to O*ff*GAR for approval before they are implemented, as it is O*ff*GAR, rather than the proponent, who is best able to judge whether the proposed changes detract or otherwise from the approved undertaking.

- North West Shelf Gas

  We request that the Regulator review experience in other locations and that prior to approving a secondary market, that the Regulator require Epic Energy to engage in thorough consultation with potential secondary market participants to discuss how such a market might operate.

  The AA documents do not provide sufficient detail to allow a reasonable assessment of the costs and practicalities of the proposed Secondary Market to be made. In particular the details on how full haul capacity entitlements might be translated into part haul entitlements to facilitate capacity trading are not explained in the AA.

- Treasury/Office of Energy

  Given that such a Secondary Market has not been in existence before, there is uncertainty as to how the market would develop and whether it would be an effective and efficient means of optimising the use of the DBNGP spare unutilised capacity. There may be a need for a trial period to provide parties with experience with the rules and to allow identification of potential deficiencies and improvements to the rules. There may also be a need for an effective consultation process, involving the Regulator, that would oversee the operation and the rules of the secondary market.

- AlintaGas Submission 3

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

- CMS Gas Transmission

  The wording of the text is both inadequate in detail and incomplete in substance. It is not clear just who is empowered to post for sale capacity which is contracted but un-nominated. Definitions are generally vague or omitted (eg. the definitions of a "Stand-in-the-market" bid, and the term "Converted Amount", respectively). The descriptions of process are at best unclear but also appear in some cases to be unworkable (eg. the timing and determination process of a sale for a Stand-in-the-market bid as described under paragraphs 4.7(a)(i)&(ii) of the Secondary Market Rules).

- WMC

  The price-setting mechanism proposed to be used is a most important part of any Secondary Market, and needs to be well defined, understood and approved by O*ff*GAR. To state that the price for Secondary Market Service will be the "prevailing market price" is far too imprecise.

As noted in section 4.5.2 of this Draft Decision, the Regulator considers that 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. This is because they are not part of the Reference Service. As such, the Regulator may be unable to require any alteration to the Secondary Market Rules and/or the related Terms and Conditions. Additionally, as the Secondary Market Service 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 described as a Reference Service. If the Secondary Market Service were withdrawn, the Regulator could not determine to not approve the proposed Access Arrangement for solely the reason that it was not included as a Non-Reference Service. However, the Regulator notes that the acceptability of the Firm Service as the Reference Service offered under the proposed Access Arrangement is subject to the Secondary Market Service being offered, since it represents the only means by which capacity can be purchased from Epic Energy on a "spot" basis.

It is within the Regulator's powers under sections 3.2, 3.9 and 3.10 of the Code to require a description of the Secondary Market Service. The Regulator considers Epic Energy has complied with those requirements in so far as it has described the Secondary Market Service in section 2.1 of the Access Arrangement Information. However, it is not clear in the proposed Access Arrangement 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 Shippers. Further, if the Secondary Market Service is, or includes, a brokerage service, it is not clear how a market price would be applied for the brokerage service. Clause 11.3 of the proposed Access Arrangement should be amended to provide a clear description of what is to be provided under the Secondary Market Service and how a market price may be applied to a brokerage component of this service, if such is intended to exist.

The Trading Policy is considered by the Regulator to generally meet the requirements of the Code regardless of the provision or otherwise of the Secondary Market Service. However, any additional effort by Epic Energy to address the concerns raised in submissions in regard to the Secondary Market Service would be welcomed.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 31<br><br>Clause 11.3 of the proposed Access Arrangement should be amended to clearly specify 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 Shippers, or both. In the event the Secondary Market Service is, or includes, a brokerage service, paragraph 11.3(e) of the proposed Access Arrangement should be amended to indicate to which type of service (pipeline capacity or a brokerage service), and the means by which, the "market price" applies. |
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**Participation by Epic Energy in the Secondary Market**

- WMC

  The proposed Rules for the Secondary Market are lacking necessary detail and confer some privileges on the proponent. For example, it is far from clear as to the priority to be accorded to the holders of contracted capacity seeking to sell on the secondary market as against uncontracted capacity to be sold by Epic. Holders of existing contractual rights should be afforded priority in the sale process as they have entered into binding longer-term commitments with large financial obligations.

- North West Shelf Gas

  There is a concern that Epic Energy propose to be both market organiser, participant and information broker/provider. It is difficult to see how these multiple roles are consistent with a well-informed and balanced market for daily pipeline capacity. In our view, if Epic Energy is to be involved as a trader in such a capacity market, then such a secondary market needs to be formed and organised by a third party and there be rules to allow for prompt distribution of information to all market participants.

- CMS Gas Transmission

  Epic state their intention to establish and run a Secondary Market for trading spare capacity. They specify that there will be two categories of sellers (Epic and Shippers who hold 'Eligible Capacity') and three categories of buyers (Epic, Shippers who hold 'Eligible Capacity' or a pre-existing transportation contract under a previous regime, and 'Approved Third Parties') in the market.

  The most critical issue is that the Secondary Market mechanism proposed by Epic should not fall under the DBNGP Access Arrangement. It is a non-Reference Service anyway, but more importantly, it should be something which is available to wider application and participation. Its inclusion by Epic appears to be an attempt to entrench a monopolistic position. Certainly Epic's own surcharge arrangements (especially the nomination surcharge) provide a strong incentive for Shippers to use the Secondary Market for fiscal relief.

- Treasury/Office of Energy

  It may not be seen appropriate for Epic Energy to determine the rules of a secondary market if it is proposing to participate as a player in it. The Regulator may wish to consider the possibility of classifying the capacity posted in the secondary market as a "market carriage pipeline" and the desirability for the Regulator to approve any amendments to the secondary market rules proposed by Epic Energy.

  In assessing whether such an arrangement adequately balances the various interests, there may be a need for the Regulator to consider whether the significant cost advantages available to Epic Energy may affect the market itself or the facility for firm Shippers to engage in alternative disposals such as via bare transfer. Essentially, Epic Energy may be willing to enter the secondary market in circumstances that recover its marginal costs (which would appear to be close to zero since other Reference Services have recovered its costs) subject to the $0.40 per GJ price floor. However firm Shippers will face a different decision, namely maximising secondary market revenue to minimise their losses (having acquired that spare capacity at full cost plus the contribution that Reference Services make towards rebatable services).

- Western Power Submission 5

  Epic Energy seeks to have a dual role in the Secondary Market. It proposes to operate and manage the market, and it may also supply uncontracted capacity into the market, thus influencing the market depending on the time of offering capacity. Western Power submits that these two roles should be, at the least, ring-fenced.

  Furthermore, because (as is appropriate) the Access Arrangement places no restriction on Epic Energy contracting with Shippers for interruptible capacity on flexible terms, Epic Energy has the ability to bypass the Secondary Market by selling flexible interruptible capacity in a way that undercuts Shippers, who are compelled by the Secondary Market rules to offer only Firm Service capacity.

  Thus, Shippers who have, for example, been forced by the inflexible treatment of seasonal capacity to acquire excess MDQ for their seasonal requirements, may be left stranded paying the 95 percent take-or-pay tariff, while Epic Energy is free to sell the unutilised capacity at a substantial discount, effectively selling the same capacity twice for a windfall gain.

- Alinta Gas Submission 3

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

As discussed above, the Regulator considers that Epic Energy has complied with its obligations under the Code with respect to its description of the Secondary Market Service as a Non-Reference Service and otherwise complies with the requirements of the Code in respect of a Trading Policy. In any event, the Regulator may not have the power to require changes to the proposed Secondary Market Rules.

Notwithstanding the potential inability of the Regulator to require changes to the Secondary Market Service and amendments to the Secondary Market Rules, the Regulator considers that concerns expressed in submissions in regard to participation of Epic Energy in the Secondary Market may be unfounded. The Secondary Market Service as described by Epic Energy appears to serve two purposes: (i) provision for Epic Energy to sell capacity on a spot basis, and (ii) provision for Epic Energy to provide a brokerage service for Users to sell unutilised contracted capacity on a spot basis. The first of these components would exist in any case for Epic Energy, regardless of whether it is described in the Access Arrangement as a Non-Reference Service. In regard to the second component, there is nothing to prevent a person other than Epic Energy from providing a brokerage service for the trading of unused contracted capacity, utilising the provisions for Bare Transfers and Conditional Transfers in the Access Arrangement and Code. In view of this contestability, the Regulator does not regard any potential conflict of interest for Epic Energy in being both broker and seller of capacity to be of concern.

Treasury/Office of Energy suggested that the Regulator consider the possibility of classifying the capacity posted in the secondary market as a "market carriage pipeline" and thereby, supposedly, regulate the provision of the Reference Service. The Regulator is of the view that the Code does not provide for the Regulator to impose a requirement on a Service Provider to manage the pipeline as either a market carriage pipeline or a contract carriage pipeline.

### Eligibility to Participate in the Secondary Market

- Western Power Submission 5

  Existing *Gas Transmission Regulations 1994* services provide Shippers with flexibility in acquiring additional capacity on a short term basis, by means of capacity trading between Shippers, as an alternative to the AT3 interruptible capacity service.

  The proposed Firm Service, however, does not have this flexibility, only firm capacity can be procured through the proposed Secondary Market Service. It appears that Shippers with *Gas Transmission Regulations 1994* contracts will not have the same trading entitlements as Firm Service Shippers in the Secondary Market.

  Western Power questions how Epic Energy can provide access to spare capacity to Shippers with *Gas Transmission Regulations 1994* contracts, while operating a Secondary Market for eligible Shippers.

  Western Power submits that Epic Energy should not be allowed to implement the proposed market trading regime, which effectively removes the rights of *Gas Transmission Regulations 1994* Shippers to have access to daily interruptible capacity, unless the *Gas Transmission Regulations 1994* Shippers are eligible to purchase and sell capacity in the Secondary Market, and the Secondary Market rules are less restrictive.

- AlintaGas Submission 3

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

The Access Arrangement for the DBNGP does not attenuate any rights of parties to *Gas Transmission Regulations 1994* contracts to purchase additional capacity on a short-term basis or to trade capacity as allowed for under those contracts. Moreover, the provisions for Bare Transfers and Conditional Transfers in the Trading Policy of the proposed Access Arrangement apply to services generally rather than just Reference Services and should serve to codify the rights of Users of services other than the Reference Service to transfer contracted capacity, subject to the specific terms and conditions of service contracts.

### Barriers to Participation in the Secondary Market

- Treasury/Office of Energy

  The Regulator may wish to consider whether applying the same prudential requirements to third-party participants in the secondary market as apply to prospective Shippers is warranted; or whether some lesser requirements would suffice. Since the original contract holders would continue to have liability for their contract quantities, it would be more appropriate for the prudential requirements in this respect to be determined by Shippers agreeing collectively on appropriate requirements.

For the reasons noted above, the Regulator considers it is not empowered under the Code to require such matters in the case of Non-Reference Services, such as the proposed Secondary Market Service. Accordingly, this will be for the parties to service contracts to resolve.

**Price Determination in the Secondary Market**

- Treasury/Office of Energy

  Epic Energy proposes a range of $0.40 to $100 per GJ for secondary market prices.

  There has been no justification of the proposed range of secondary market prices applying to Epic Energy's activities in the secondary market. It may be appropriate for such prices to be struck for the various Delivery Points.

As noted above, the Regulator considers it would not be appropriate, nor necessarily possible, to require Epic Energy to set particular prices for the proposed Secondary Market.

However, Epic Energy commented on the concerns raised in submissions in its submission 6, indicating that it intends to give further consideration to these and other issues raised in respect of the proposed Secondary Market. The Regulator would welcome any attempt by Epic Energy to further clarify the operation of the Market.

### 4.5.4 Additional Considerations of the Regulator

The Regulator has no concerns with the Trading Policy in addition to matters addressed above in responses to public submissions.

## 4.6 QUEUING POLICY

### 4.6.1 Access Code Requirements

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).

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.

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, being:

(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; and

(g) any other matters that the Regulator considers are relevant.

### 4.6.2 Access Arrangement Proposal

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; and
- the Queuing Policy is subject to any Capacity Expansion Options which may be granted by Epic Energy from time to time – 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.[46]

### 4.6.3 Submissions from Interested Parties

#### Insufficient Detail Provided

- Western Power Submission 5

  While the Queuing Policy proposed might meet the Code requirements in terms of a policy, there is too little information to identify how the policy is to be implemented.

- Robe River Mining

  Under Sections 3.12 to 3.15 of the Code the Access Arrangement must include a Queuing Policy which explains the priorities of Users and Prospective Users in obtaining access to the DBNGP.

  We submit that paragraph 5.3 of the Access Arrangement fails in that regard since it does not provide sufficient detail to enable Users and Prospective Users to understand in advance how a priority will be assigned and to the extent reasonably possible accommodate the legitimate business interests of the Users and Prospective Users or generate economically efficient outcomes.

These submissions are addressed below in responses to other submissions indicating concerns as to specific perceived deficiencies of the Queuing Policy and particular concerns of the Regulator.

#### Updating Information on the Position of an Access Request in the Queue

- Western Power Submission 5

  Whenever a Shipper makes an Access Request for the Reference Service, and there is insufficient capacity to meet the request, then information is provided by Epic Energy to the Shipper in respect of this Shipper's place in the queue and a non-binding estimate of when capacity may become available.

  However, there needs to be appropriate provision in the Access Arrangement for routinely updating this information depending on the requested commencement date and the current status in respect of criteria to be met in relation to an expansion or enhancement.

The Regulator notes that the Queuing Policy makes no provision for any notification of Prospective Shippers regarding the status of pending Access Requests in the queue. The Regulator considers that clause 5.3 should be amended to require Epic Energy to notify

[46] 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.

Prospective Shippers of the status of their Access Requests. Further, if Epic Energy has notice of a change in the time when the requested capacity may become available which is material in the context of the Prospective Shipper's application, then Epic Energy should notify the Prospective Shipper of the changed timing.

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 32

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 33

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.

### Power to Reject Access Request and Power to Change Priority Order

- WMC

  WMC has no particular objection to the proposed Queuing Policy except to urge O*ff*GAR to ensure that the final rules are very clear as to the priority order of applications being processed, and to ensure that the proponent only has discretion to changing the priority order under clearly stated and reasonable circumstances.

- Western Power Submission 5

  The proposed Access Arrangement allows Epic Energy to deal with Access Requests out-of-order providing earlier Access Requests are not ultimately disadvantaged. Western Power considers that in such instances the prior written consent of the affected Shipper should be sought by Epic Energy and provision made to arbitrate any dispute. It seems unreasonable that Epic Energy should be able to determine such a matter in its sole discretion.

- Treasury/Office of Energy

  Epic Energy may deal with Access Requests out of order provided that the Access Requests, which were first in time are not ultimately disadvantaged.

  It would be helpful if Epic Energy offers an indication of the possible situations the above might occur.

- Robe River Mining

  Paragraph 5.3(c) of the Access Arrangement allows Epic to reject an Access Request at any stage prior to its acceptance. This should only be permitted where Epic can demonstrate sound reasons for rejecting the Access Request; otherwise the concept of queuing for Capacity as and when it becomes available is defeated.

Epic Energy responded to submissions relating to the ability of Epic Energy to deal with Access Requests "out of order".[47] Epic Energy indicated that:

> This provision would not be expected to have any application in the Reference Queue. However, it may be needed in dealing with applications in the Non-Reference Queue where Access Requests could vary dramatically in the matters needing to be assessed or negotiated. For example, there may be in the Queue an Access Request which is for the Reference Service with a small amendment which does not cause Epic Energy any concern. It could be sitting behind an Access Request requiring substantive amendments, which could take many months to negotiate or resolve. The first mentioned Access Request would ordinarily have to wait until the other application is processed, yet there may be no issues surrounding it.

Further:

> The provision also enables Epic Energy to avoid mischievous applicants clogging up the system to the detriment of genuine applicants.

Clause 5.3(a) of the proposed Access Arrangement makes provision for Epic Energy to deal with Access Requests out of order provided that Users are not "ultimately disadvantaged". Ambiguity exists, however, in regard to the meaning of "ultimately disadvantaged". The Regulator considers that the ability Epic Energy has, under sub-clause 5.3(a) of the proposed Access Arrangement, to deal with Access Requests out of order should be explained and defined in more detail. Furthermore, the Regulator considers that provision should be made for prior notice to be given to affected Prospective Shippers in the queue if Access Requests are to be dealt with out of order for whatever reason.

Sub-clauses 5.3(b) and (c) are also imprecise as to the circumstances in which an Access Request may be rejected. It is noted that sub-clause 5.2(c) and (d) set out particular circumstances in which an Access Request may be rejected. Subject to any amendments required in this Draft Decision relating to clause 5.2 and if the circumstances for rejection described in clause 5.2 are intended to apply to clause 5.3, clause 5.3 should be amended to refer to clause 5.2 for the purposes of rejection.

The following amendments are required before the proposed Access Arrangement will be approved.

| Amendment 34<br><br>Clause 5.3 of the proposed Access Arrangement should be amended to define in detail what is meant by "ultimately disadvantaged", and to provide for all affected Prospective Users with Access Requests in the queue to be notified if any Access Requests are to be dealt with out of order. |
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| Amendment 35<br><br>Clause 5.3 of the proposed Access Arrangement should be amended to state the circumstances in which an Access Request may be rejected. |
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[47] Epic Energy Submission 9.

### Separate Queues for Separate Services

- Western Power Submission 5

> There is a question as to whether there should be separate queuing for each service or a single queue for all services. To the extent that services are independent then queues for each service would be appropriate and vice versa.
>
> For instance a Park and Loan Service may conflict with a request for a Seasonal Service, but would not conflict with a request for Firm Service. Such analysis supports the proposed Queuing Policy, but only so far as the two services do not interact. However, a Non-Reference full-haul firm service Access Request, which may clash with a Firm Service Access Request, should be included in the same queue to ensure an equitable allocation of spare capacity.
>
> The Regulator is requested to consider the limitation that appears to stem from Epic Energy's interpretation of the Code, insofar as only one queue is outlined in their submission. This, if implemented, would inhibit access to a range of services.

Clause 5.3 of the proposed Access Arrangement provides for only one queue for Access Requests for any service (Reference or Non-Reference). It is noted that under sub-clause 5.3(a), there is some potential for separate queues for each service since "Access Request" is defined in the proposed Access Arrangement to include Access Requests for Reference and Non-Reference Services. Under section 3.12 of the Code, the Queuing Policy must describe priority as between prospective users for access to spare capacity and developable capacity. This suggests that more than one queue may be appropriate, but not that a separate queue should be provided for each service offered. Accordingly, the Regulator considers that the Queuing Policy should provide for separate queues to the extent the different services described in the proposed Access Arrangement are independent in their use of capacity (in the sense that the capacity used to provide one service does not reduce the extent to which capacity is available to provide another).

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 36 |
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| Clause 5.3 of the proposed Access Arrangement is required to 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. |

### Interaction between Queuing Policy and Capacity Expansion Options

- Robe River Mining

> The Capacity Expansion Option scheme overrides the Queuing scheme and the Queuing scheme is scant in detail as to when a party in the queue will become entitled to Capacity.
>
> Clause 5.3 sets out the queuing policy. The queuing policy is expressed to be subject to any Capacity Expansion Options which may be granted by Epic from time to time. Capacity Expansion Options are described in paragraph 12. Apart from the concept of selling Capacity Expansion Options which can be traded there does not appear to be any other substance to the queuing policy. We submit that the queuing policy should be detailed more fully.

- Treasury/Office of Energy/

> The interaction between the queuing policy and Capacity Expansion Options should be examined closely. Given that exercised Capacity Expansion Options will receive priority to prospective Shippers in the queue, the initial allocation of the Capacity Expansion Options has the potential to subvert the queuing policy if they are not available on an open basis. The Regulator may wish to consider whether the Capacity

Expansion Option terms and conditions, including purchase price, should be published by Epic Energy on a regular basis. On the other hand, the ability to trade these options is seen as a positive step.

- Western Power Submission 5

  Epic Energy's policy proposes that it may offer Capacity Expansion Options. Until such Capacity Expansion Options are issued, Shippers' rights for additional capacity presumably lie in Access Requests and their position in the queue.

  It is unclear how these two methods of indicating a desire for additional capacity are to interact. In the absence of Capacity Expansion Options, an Access Request seeking additional capacity must remain active and could be accepted at any time. It is not tradeable. On the other hand, Capacity Expansion Options will be tradeable and will rank in priority to queued Access Requests.

  This means that an incumbent applicant in the queue for the proposed Firm Service could be displaced by the device of offering a subsequent applicant a Capacity Expansion Option, to be taken up immediately. This does not appear consistent with the requirements set out in section 3.13 of the Code.

  Western Power asks the Regulator to ensure that the proposed Queuing Policy by Epic Energy concerning capacity extensions and expansions, complies with the Code.

The Regulator notes the submissions indicating concerns that Capacity Expansion Options may be used to subvert the queue. Any potential for this may be limited if Capacity Expansion Options only relate to capacity that becomes available as a result of a particular expansion or extension. However, under clause 12 of the proposed Access Arrangement it is not clear whether the holder of a Capacity Expansion Option has the right to call for capacity generally to be provided or, rather, only the right to call for the provision of capacity which results from a particular expansion or extension of the DBNGP.

If the intention is that Capacity Expansion Options apply to capacity generally and not just that which results from a particular expansion or extension of the DBNGP, then the ability to use Capacity Expansion Options to jump the queue may promote allocative efficiency on the basis of a willingness to pay. This may have some advantages in terms of efficiency of allocation of scarce capacity. However, a disadvantage is that Epic Energy may capture rents associated with the scarcity of capacity and provide some disincentive for Epic Energy to undertake expansions or extensions. It is considered that it would be in the interests of Prospective Users for Capacity Expansion Options to only be capable of being exercised to secure capacity that becomes available as a result of an expansion or extension of the DBNGP and to which the Capacity Expansion Option exercised expressly relates.

Clause 5.3 does not address priority where a Capacity Expansion Option is taken up while others are pending at the time or in fact whether it will be possible to acquire an Option in respect of certain specified capacity where another Option has already been issued to another person. Whether the latter can occur and, if so, priority as between Capacity Expansion Options should therefore be described in clause 5.

The following amendments are required before the proposed Access Arrangement will be approved.

| Amendment 37 |
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| 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 capacity which becomes available as a result of an expansion or extension of the DBNGP to which the Capacity Expansion Option expressly relates. |

Amendment 38

Clause 5.3 of the proposed Access Arrangement should be amended to describe priority as between Capacity Expansion Options.

**First Right of Refusal for Renewal of Existing Contracts**

- Worsley Alumina

  The Queuing Policy does not appear to guarantee continuity of access for existing users. Projects that require gas for the long term require continuity of supply but, in the face of uncertainty in their own markets, only enter ‘take or pay’ contracts for the minimum term that balances the risk between the user and the pipeline owner. Existing users should be able to expect ‘right of first refusal’ over their contracted capacity but this does not appear to be acknowledged in the queuing policy. Note that this policy refers to ‘existing and new’ users collectively.

The Regulator notes that the proposed Access Arrangement does not expressly provide for any right of first refusal for renewal of existing contracts. It may be possible for Shippers to address this by acquiring a Capacity Expansion Option to secure future access. However, this is subject to Epic Energy offering Capacity Expansion Options and the Options corresponding with the capacity required. It may be possible to acquire capacity on the Secondary Market, but this is similarly subject to availability and cannot provide any long-term security of access. These potential shortcomings must be balanced against Epic Energy’s legitimate business interests as a Service Provider and its obligations to other Users and Prospective Users, which may favour not providing for any right of first refusal. In the Regulator’s view, however, Shippers may be unable to manage their businesses without some certainty of future access. Accordingly, the proposed Access Arrangement should be amended such that a Service Agreement for a Reference Service is capable of including an option to extend the term of that agreement without being subject to the Queuing Policy.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 39

Clause 12 of the proposed Access Arrangement should be amended to 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.

### 4.6.4 Additional Considerations of the Regulator

Generally, the Regulator considers 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, as required under paragraph 3.13(a) of the Code. Some deficiencies in this respect were addressed above in relation to public submissions. An additional concern of the Regulator is that the Queuing Policy does not describe what will happen when an Access Request in the queue is withdrawn and re-submitted or simply amended. It may be that Epic Energy intends these events to fall within sub-clause 5.3(a). Whether or not this is the case, clause 5.3 should be amended to describe what will occur. Particularly, the effect of amending an Access Request by increasing or decreasing the requested capacity should be addressed.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 40<br><br>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. |

## 4.7 EXTENSIONS/EXPANSIONS POLICY

### 4.7.1 Access Code Requirements

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.

The Regulator may not require the Extensions/Expansions Policy to state that the Service Provider will fund New Facilities, unless the Service Provider agrees.

### 4.7.2 Access Arrangement Proposal

Epic Energy has provided an Extensions/Expansion Policy in clause 12 of the proposed Access Arrangement. Under the policy, Epic Energy will enhance or expand the capacity of the DBNGP where it considers the requirements of section 6.22 of the Code are satisfied. It will otherwise enhance or expand capacity as it sees fit.

Under the policy, 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 Shipper a right to a specified quantity of capacity on particular terms and conditions. Capacity Expansion Options will have a particular purchase price determined by

Epic Energy and are capable of being traded with other Prospective Shippers. Expansions of the DBNGP pursuant to Capacity Expansion Options will be treated as part of the Covered Pipeline unless Epic Energy states otherwise.

Any expansion or extension not made for the purposes of fulfilling obligations under a Capacity Expansion Option will only become part of the Covered Pipeline where Epic Energy so elects and submits notice to the Regulator. Expansions or extensions of the DBNGP that become part of the Covered Pipeline will not affect Reference Tariffs in the current 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 Shipper using incremental capacity will pay the Reference Tariff.

### 4.7.3 Submissions from Interested Parties

**Purchase Prices for Capacity Expansion Options and Capital Contributions for New Facilities**

- Robe River Mining

  Clause 12.3 of the Access Arrangement permits Epic Energy to determine whatever purchase price it considers appropriate for sale of a Capacity Expansion Option. We submit that the purchase price should be reasonable relative to the cost of providing the Capacity Expansion.

  Clause 12.7 of the Access Arrangement permits Epic to seek surcharges or capital contributions from Prospective Shippers in respect of New Facilities Investment. No principles are described as to the quantum or the size of those surcharges or capital contributions. We submit that for consistency with section 8.25 of the Code, these principles should be incorporated.

The Regulator has considered its power under the Code to require Epic Energy to specify a particular price for Capacity Expansion Options or to require that the price be reasonable according to certain benchmarks. It is considered that under section 3.16 of the Code, the Regulator has no power to require a description of how any expansions or extensions will be funded. Section 8.23 of the Code illustrates this in addressing capital contributions from Users towards New Facilities Investment. However, it is considered that it would be in the interests of Users and Prospective Users if the nature of the purchase price were described in greater detail. Accordingly, the proposed Access Arrangement should be amended to clearly explain whether the purchase price of a Capacity Expansion Option represents the relevant Shipper's only required contribution to the cost of the expansion or extension pertaining to the Option or whether it represents no more than a price for the facility (in terms of transferability and otherwise) given by the Option itself.

In regard to provisions of clause 12.7 of the proposed Access Arrangement for Epic Energy to seek surcharges or capital contributions from Prospective Shippers in respect of New Facilities Investment, under section 8.23 of the Code Epic Energy is not required to specify in advance the size of any capital contribution that will be required to finance an expansion or extension of a Covered Pipeline. This may be sensible for practical reasons as the exact cost of the extension or expansion may not have been determined at that time.. However, it is likely that the circumstances in which capital contributions will be sought under clause 12.7 of the proposed Access Arrangement can be generally described. The Regulator considers such a description should be set out in the Access Arrangement.

Under section 8.25 of the Code, any surcharge must be submitted to the Regulator for approval. As for capital contributions, it is considered that it would be in the interests of Users and Prospective Users for a general description of the circumstances in which surcharges are likely to be sought to be described in the Access Arrangement. Accordingly, clause 12.7 of the proposed Access Arrangement should be amended to include a description of the circumstances in which surcharges are likely to be sought, and for the imposition of surcharges to be subject to Epic Energy providing written notice to the Regulator in accordance with section 8.25 of the Code.

The comments made above in relation to the interaction of the Queuing Policy and Capacity Expansion Options should also be noted (section 4.6 of this Draft Decision).

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 41

Clause 12 of the proposed Access Arrangement should be amended to clearly explain whether the purchase price of a Capacity Expansion Option represents a capital contribution by the relevant User to the cost of the extension or expansion pertaining to the option, or whether the purchase price of a Capacity Expansion Option represents no more than a price for the facility given by the option itself.

Amendment 42

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 43

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 an intent to impose surcharges.

Amendment 44

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.

**Decisions for an Extension/Expansion to Become Part of the Covered Pipeline**

- Western Power Submission 5

  The Extensions/Expansions Policy provides for extensions and expansions to be treated as part of the Covered Pipeline unless Epic Energy states otherwise. However it does not provide the basis or method upon which Epic Energy may make such a decision and as such does not appear to conform to the Code.

Under clauses 12.4 and 12.5 of the proposed Access Arrangement, expansions and extensions will become part of the Covered Pipeline unless, in the case of clause 12.4, Epic Energy states otherwise and, in the case of clause 12.5, Epic Energy elects otherwise and provides notice of that election to the Regulator. The Regulator considers that the proposed clauses are generally acceptable, but that clause 12.4 should be amended to state that Epic Energy will provide written notice to the Regulator of any decision not to include in the Covered

Pipeline any expansion or extension which results from the exercise of a Capacity Expansion Option.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 45<br><br>Clause 12.4 of the proposed Access Arrangement should be amended to state that Epic Energy will provide written notice to the Regulator of any decision not to include in the Covered Pipeline any expansion or extension which results from the exercise of a Capacity Expansion Option. |

**Impacts of Extensions/Expansions on the Reference Tariff**

- Western Power Submission 5

  The policy adequately describes the impact of extensions/expansions on the Reference Tariff except that it is not clear that if a capital contribution is made the tariff will be reduced by an amount to reflect the value of the capital contribution. This may perhaps be remedied by making it clear that Epic Energy's ability to seek surcharges and capital contributions is subject to the Code, which may well be intended in any event.

Clause 12.8 of the proposed Access Arrangement states that except where a surcharge is imposed or capital contributions sought, Shippers using incremental capacity will pay the Reference Tariff.

It is noted that under section 6 of the Code, particularly section 6.23, provision is made for a specific mechanism by which Prospective Users may be entitled to obtain a rebate on the Reference Tariff. As such, it is not considered necessary for the Access Arrangement to re-state the provisions of section 6.23. However, it is considered that it would be in the interests of Users and Prospective Users if section 12 of the proposed Access Arrangement were 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. Accordingly, the Regulator considers that clause 12.7 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.

It is also noted that under clause 12.6 of the proposed Access Arrangement, expansions or extensions that become part of the Covered Pipeline will not affect the Reference Tariff until before the commencement of the subsequent Access Arrangement Period. This suggests the Reference Tariff may in fact change. If this occurred, it would conflict with statements by Epic Energy (see for example page 30 of the Access Arrangement Information) that the Reference Tariff will not change for the 20 years following approval of the proposed Access Arrangement, other than in accordance with the specified tariff path. The Regulator notes, however, that amendments required to the proposed Access Arrangement as set out in this Draft Decision will negate the requirement for Epic Energy to maintain the fixed tariff path. As such, the Regulator does not have a concern with the Extensions/Expansions Policy providing for a change in the Reference Tariff, although noting that the Reference Tariff may only be changed by means of a review of the Access Arrangement under the relevant provisions of part of the Code.

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 46

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.

### 4.7.4 Additional Considerations of the Regulator

The Regulator has no concerns with the Extensions/Expansions Policy proposed by Epic Energy in addition to matters addressed above in response to public submissions.

## 4.8 REVIEW DATE

### 4.8.1 Access Code Requirements

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).

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 its 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:

(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.

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 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.

Where a mechanism is included in an Access Arrangement pursuant to paragraph 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.

### 4.8.2 Access Arrangement Proposal

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.

### 4.8.3 Submissions from Interested Parties

### Triggers for Review of the Access Arrangement

- WMC

  WMC understands that *Off*GAR can only accept or reject an Access Undertaking and cannot revoke an acceptance once given. Once accepted, the Undertaking prevails for the duration of the Access Undertaking Period (proposed to be 1st January 2005).

  In these circumstances, it is most important that *Off*GAR ensures that the initial Access Arrangement includes all of the features required and is capable of being accepted under the Code. It is also essential that the proponent agrees in the Access Undertaking to resubmit all or part of the Undertaking in the event that circumstances change to an extent which questions or undermines the assumptions made when the Undertaking was submitted.

  Depending on the final approach adopted in selecting the WACC value and its treatment of tax (addressed later in this submission), one such circumstance would be a change in the corporate tax rate - as is being proposed by the Commonwealth Government at present. There may be other specific changes of circumstances which become apparent to *Off* GAR in the assessment process which should also trigger a review of particular aspects of the Access Undertaking.

- Western Power Submission 5

  The proposed Revisions Submission Date and Revisions Commencement Date appear reasonable, however, triggers that may be considered appropriate for earlier review are:

  – completion of a significant expansion (indicating a significant change in use not foreshadowed in the previous Access Arrangement); and

  – new gas supply sourcing becoming available to the DBNGP at points downstream of Zone 1 (implying some restructuring of the method of cost allocation).

  Western Power asks the Regulator to take the above comments into account concerning opportunities for the DBNGP Access Arrangement review date.

- Treasury/Office of Energy

  It should be noted that the Mid West Iron and Steel Project announced on 28 January 2000 that it has achieved a significant milestone in the path to securing financial commitment to that Project. The proponents anticipate commencement of operations at the Oakajee site in 2003. Such an outcome would substantially increase the throughput of the DBNGP in the middle of the period proposed for the Access Arrangement. It would also crystallise the need for a further investment to enhance the DBNGP capacity at least to Geraldton, and increase the asset base of the DBNGP. The Regulator should seek confirmation of that expectation from Epic Energy and, if appropriate, a revision to the proposed Access Arrangement and supporting Access Arrangement Information.

The above submissions have indicated a view that it may be appropriate to include trigger mechanisms in the Access Arrangement such that a review of the Access Arrangement would occur in the event that there is a substantial change in operation of the DBNGP such as a significant expansion of pipeline capacity, a significant increase in throughput, or receipt of gas into the pipeline from a new gas source downstream of Zone 1.

Under amendments required to the proposed Access Arrangement in respect of the Services Policy, Epic Energy will be required as part of the Firm Service to accept gas in all zones, not just zone 1. That is considered to remove any need for a trigger mechanism relating to receipt of gas from new gas sources.

The Regulator notes that increases in throughput in the DBNGP in excess of 120 TJ/day (approximately 22 percent of current and forecast throughput) may require extensions or expansions of the DBNGP. While significant expansions or extensions which become part of the Covered Pipeline may be expected to have an effect on the Reference Tariff, under the Expansions/Extensions Policy the effect on the Reference Tariff will not occur until after the revisions commencement date (assuming revisions are duly submitted and then approved by the Regulator). If changes to Reference Tariffs are desired prior to that time, then it remains open for Epic Energy to submit revisions at any time. Accordingly, it is not considered necessary at this stage for the Access Arrangement to provide for a review to be triggered by extensions to or expansions of the pipeline.

### 4.8.4 Additional Considerations of the Regulator

In addition to matters raised in submissions, the Regulator has given attention to the proposed Revisions Submission Date and Revisions Commencement Date, and to whether it is necessary to provide for trigger mechanisms to initiate a review of the Access Arrangement.

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. In view of regulatory experience throughout Australia, the Regulator considers that a six-month period is inadequate for assessment of a proposed Access Arrangement and will require that the Revisions Submission Date be brought forward to allow a nine-month period for assessment.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 47<br><br>Clause 13 of the proposed Access Arrangement should be amended to provide for a Revisions Submission Date of at least nine months prior to the Revisions Commencement Date. |
|---|

The Regulator gave detailed consideration to the specification of trigger mechanisms in the Access Arrangement for the AlintaGas Mid-West and South-West Gas Distribution Systems[48]. In particular, attention was given to:

- whether or not the Regulator can reserve discretion as to whether a review of an Access Arrangement should proceed once a defined trigger event occurs; and
- what specific major events within the meaning of section 3.17 of the Code are appropriate to trigger an obligation on the Service Provider to submit revisions to the Access Arrangement prior to the Revisions Submission Date.

[48] AlintaGas Mid-West and South-West Gas Distribution Systems Final Decision 30 June 2000, pp 62-67.

On the basis of legal advice that section 3.17 of the Code does not expressly give the Regulator any discretion as to whether a review should proceed once a defined trigger event occurs[49], the Regulator considered it appropriate to adopt a more tightly defined set of triggers than would have been necessary had discretion to trigger a review been available to the Regulator.

Having regard to the objectives for design of Reference Tariffs and a Reference Tariff Policy as set out in section 8.1 of the Code, the Regulator considers that a review of an Access Arrangement should only be triggered where it is justified by the potential benefits from such a review. The following major events are of a type that could justify a review for the purposes of section 3.17 of the Code:

- realised quantities of gas throughput significantly exceeding forecast quantities that were the basis for determining the Reference Tariff;
- significant changes in taxation liabilities of the Service Provider arising from a change in law; and
- significant changes in costs to the Service Provider arising from changes in regulatory arrangements affecting the provision of services.

In regard to a trigger mechanism in respect of gas throughput, the Regulator notes that for the DBNGP a 25 percent increase in pipeline throughput would not be possible without substantial New Facilities Investment, which has not been taken into account in determination of Reference Tariffs (see section 5.4 of this Draft Decision). Given this, the Regulator does not consider that it is necessary to make provision for triggering of a review of the Access Arrangement on the basis of realised gas throughput.

In regard to taxation and regulatory changes, the Regulator has taken into account the objective set out in section 8.1(b) of the Code that Reference Tariffs should replicate the outcome of a competitive market, which would see any cost reductions from changes in taxation or regulatory arrangements passed through to consumers in lower prices. However, the Regulator also took into account that as these changes in costs may only be passed through to changes in Reference Tariffs by way of a review of the Access Arrangement, the changes in costs to trigger a review must be of a sufficiently high magnitude that the benefits of review of the Access Arrangement, and reductions to Reference Tariffs should exceed the costs of a review. The Regulator concluded that an appropriate magnitude of a change in total costs would be 5 percent of forecast revenue for any given year of the Access Arrangement Period (amounting to approximately $8.25 million, refer to section 5.8 of this Draft Decision).

The following amendment is required before the proposed Access Arrangement will be approved.

[49] Once events have been defined as 'specific major events' for the purposes of section 3.17 of the Code, their occurrence will oblige the Service Provider to submit revisions to the Access Arrangement in accordance with section 2.28 of the Code. The Regulator is then required to conduct a review in accordance with Part 2 of the Code.

Amendment 48

The proposed Access Arrangement should be amended to specify that Epic Energy will submit revisions of the Access Arrangement to the Regulator:

– within three months of the day on which a change in regulation that arises from a change in law takes effect, or the day on which it becomes sufficiently certain that the change will take effect, whichever is earlier, that has the effect of reducing the costs that Epic Energy is required to pay, or is likely to be required to pay, in the subsequent calendar year of the Access Arrangement Period in relation to its supply of one or more services by an amount of 5 percent or more of the Total Revenue for that calendar year; and

– within three months of a change in taxation that arises from a change in law takes effect, or the day on which it becomes sufficiently certain that the change will take effect, whichever is earlier, that has the effect of reducing the costs that Epic Energy is required to pay, or is likely to be required to pay, in the subsequent calendar year of the Access Arrangement Period in relation to its supply of one or more services by an amount of 5 percent or more of the Total Revenue for that calendar year.

## 4.9 OTHER MATTERS ADDRESSED IN THE PROPOSED ACCESS ARRANGEMENT

### 4.9.1 Access Code Requirements

Section 2.24 of the Code requires that an Access Arrangement contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Code. An Access Arrangement may, however, address matters or provide information beyond the requirements of sections 3.1 to 3.20 of the Code.

The Regulator may 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. However, should a proposed Access Arrangement address matters in addition to the requirements of sections 3.1 to 3.20 of the Code, then the Regulator has broad discretion to refuse to accept the proposed Access Arrangement if the additional matters are considered not reasonable. In assessing any additional matters included in a proposed Access Arrangement, the Regulator may take into account the factors listed in section 2.24 of the Code:

(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; and

(g) any other matters that the Relevant Regulator considers are relevant.

### 4.9.2 Submissions from Interested Parties

**Access Requests**

- Robe River Mining

  Clause 5.2 of the Access Arrangement allows Epic to request such further detail and information from a Prospective Shipper as Epic reasonably considers necessary. Epic's ability to do so should be limited in order to prevent abuse and the reasons for the requests should be transparent.

  It is submitted that the Regulator should consider whether Epic should only be able to request further information where:

  (a) it relates directly to assessment of the Access Request;

  (b) it is reasonable to do so (as distinct from being reasonable in Epic's opinion); and

  (c) Epic states clearly the reasons for requesting the additional information.

  Clause 5.2(d) of the Access Arrangement provides that an Access Contract will only arise where the Access Request is accepted by Epic. There should be a stipulation obliging Epic to accept an Access Request where there is spare Capacity.

  Whilst the terms and conditions for Non-Reference Services are negotiable, the procedures for accessing those services are pre-determined by Epic in advance. For example, paragraph 2.3(e) of the Access Guide imposes pre-conditions for the negotiations by entitling Epic to reject Access Requests for Non-Reference Services thus precluding a request from being placed in the Non-Reference Queue, in certain circumstances.

Under sub-clause 5.2(b) of the proposed Access Arrangement, Epic Energy may request "such further detail and information … as Epic Energy reasonably considers necessary". While that further detail and information which Epic Energy may consider reasonable may correspond with what may be considered objectively reasonable, that may not always be the case. In the interests of Prospective Users and to provide certainty, sub-clause 5.2(b) should be amended such that the additional information may only be requested where it may be objectively considered reasonably necessary for the purpose of assessing the corresponding Access Request.

Additionally, under section 5.1 of the Code, Epic Energy is required to publish an Information Package setting out particular types of information, including a detailed description of the information it will require in order to process an Access Request. The Regulator considers that clause 5.2 of the proposed Access Arrangement should be amended to state that the types of information which Epic Energy may request under sub-clause 5.2(b) are those set out in the Information Package and that information requests will made in accordance with the Information Package.

The following amendments are required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 49<br><br>Sub-clause 5.2(b) of the proposed Access Arrangement, relating to provision for Epic Energy to obtain further information from a Prospective User in relation to an Access Request, should be amended to state that "the further detail and information" may only be requested by Epic Energy where it may be objectively considered reasonably necessary for the purpose of assessing the corresponding Access Request and any request for information is in accordance with the Information Package. |

## Conditional Access Requests

- Treasury/Office of Energy

  In the context of its rules for accepting access requests and its queuing policy, it is not clear how Epic Energy is proposing to deal with applications of prospective Shippers that may be competing by tender to supply a new project. Each prospective Shipper is likely to be required by the tender process to have some degree of certainty regarding transport of gas but only one would succeed in the tender process. It is also not clear if the Capacity Expansion Options or capacity reservation options would be available to these tenderers.

Epic Energy[50] responded to the submission from Treasury/Office of Energy indicating that while the current Access Manual provides for conditional access requests, such a provision in the Access Arrangement would not add to the rights of Prospective Users as under the proposed Access Arrangement anything can be agreed. Further, Epic Energy indicated that an absence of explicit provision for conditional access requests, necessitating that any such access request be negotiated with Epic Energy, has an advantage of flexibility in being able to address specific circumstances in which such an access request is required.

The Regulator notes that under clause 43 of the current Access Manual, it has been possible for Users to request a conditional access contract. A conditional access contract was considered to be equivalent to an unconditional access contract in all respects, save for the fulfilment of any condition precedent specified in the request. The condition (or conditions) precedent had to be fulfilled and notified to the DBNGP owner within 3 months of the date the request was made. Importantly (from the point of view of limiting any potential for abuse of the procedure), a conditional access contract could not be entered into if an equivalent unconditional access contract would not be entered into.

The Regulator has reviewed the proposed Access Arrangement and Access Manual. It is considered that clause 43 of the Access Manual does more than simply provide that the parties may agree to anything, contrary to Epic Energy's submission. The benefits to users of a mechanism for making conditional Access Requests are considered likely to outweigh the costs (if any) and inconvenience to Epic Energy. Accordingly, the proposed Access Arrangement should be amended to provide for a mechanism for the making of conditional Access Requests, substantially in the form of clause 43 of the Access Manual. It is considered that conditional Access Requests should be subject to the Queuing Policy.

The following amendment is required before the proposed Access Arrangement will be approved.

| Amendment 50 |
|---|
| The proposed Access Arrangement should be amended to set out a mechanism substantially similar to clause 43 of the Access Manual for the making of Access Requests that are conditional upon fulfilment of conditions precedent specified in the request. |

[50] Epic Energy Submission 9.

# 5 REFERENCE TARIFFS

## 5.1 INTRODUCTION

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.

The principles used to determine Reference Tariffs are to be stated as a Reference Tariff Policy. Both the Reference Tariff Policy and the Reference Tariffs should be designed with a view to achieving the objectives set out in section 8.1 of the Code:

(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.

Epic Energy has proposed a Reference Tariff for the Firm Service. In accordance with the principles established by the Code, Epic Energy used a price path methodology for the determination of the Reference Tariff. With this approach, a Reference Tariff is determined in advance for the Access Arrangement Period. The Reference Tariff follows a path that is forecast to deliver predetermined revenue, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period.

The Code provides a general procedure for the application of the price path methodology to the determination of Reference Tariffs. The steps in this general procedure are:

- estimation of an Initial Capital Base;
- estimation of Capital Expenditure;
- estimation of Non-Capital Costs;
- estimation of an appropriate Rate of Return;
- specification of a Depreciation Schedule;
- determination of Total Revenue;
- determination of a cost/revenue allocation across services;
- determination of Reference Tariffs; and
- specification of Incentive Mechanisms.

This chapter provides an assessment of compliance of the proposed Reference Tariff with the requirements of the Code. This is undertaken by examining the general methodology used by Epic Energy in determining the Reference Tariff for the Firm Service and individual parameters of the related financial analysis, taking into account the requirements of the Code and submissions from interested parties.

## 5.2 METHODOLOGY USED TO DETERMINE REFERENCE TARIFFS

### 5.2.1 Access Code Requirements

Section 8.3 of the Code provides for the methodology for determination of Reference Tariffs to be at the discretion of the Service Provider, subject to the Regulator being satisfied that the methodology is consistent with the objectives contained in section 8.1 of the Code. Notwithstanding this, section 8.3 of the Code states that Reference Tariffs may be determined by:

(a) a price path approach, whereby a series of Reference Tariffs are determined in advance for the Access Arrangement Period to follow a path that is forecast to deliver a revenue stream calculated consistently with the principles in section 8 of the Code, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period;

(b) a cost of service approach, whereby the Tariff is set on the basis of the anticipated costs of providing the Reference Service and is adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the Tariff recovers the actual costs of providing the Service; or

(c) variations or combinations of these approaches.

### 5.2.2 Access Arrangement Proposal

Epic Energy has adopted a price path approach in the specification of Reference Tariffs, whereby the Reference Tariff for the Firm Service is determined in advance for the Access Arrangement Period.

Epic Energy's use of the price path approach is different to the methodology described in paragraph 8.3(a) of the Code, inasmuch as the specified Reference Tariff was determined independently of the required revenue stream (Total Revenue) calculated with a view to the principles outlined in section 8 of the Code. That is, Epic Energy determined the Total Revenue for the DBNGP in accordance with the guidelines provided by the Code, but then determined a Reference Tariff and path for that Reference Tariff that is independent of the Total Revenue and which would return an actual revenue over the Access Arrangement Period that is less than the calculated Total Revenue for that period. Epic Energy has proposed a Reference Tariff Policy that capitalizes the shortfall in revenue as "deferred depreciation", with an intended recovery of the shortfall in future time periods, possibly beyond the current Access Arrangement Period.

### 5.2.3 Submissions from Interested Parties

No submissions addressed generally the price path approach adopted by Epic Energy in respect of the specification of Reference Tariffs. Several submissions made comment on particular aspects of Epic Energy's determination of the Total Revenue for the DBNGP. The matters raised in submissions are addressed is subsequent sections of this Draft Decision.

### 5.2.4 Additional Considerations of the Regulator

The Regulator recognises that section 8.3 of the Code provides a Service Provider with discretion in determining the general methodology used for the determination of Reference Tariffs and the manner in which Reference Tariffs will vary within the Access Arrangement Period, subject to the chosen methodology being consistent with the objectives of section 8.1 of the Code. The price path methodology adopted by Epic Energy is consistent with methodologies contemplated by the Code in so far as the Reference Tariff and process of variation in the Reference Tariff are established in advance for the Access Arrangement Period. However, the Code does not explicitly contemplate a methodology, as proposed by Epic Energy, whereby a Reference Tariff is established that will result in a recovery of revenue that is less than the Total Revenue calculated according the principles set out in section 8 of the Code.

The acceptability of the methodology proposed by Epic Energy depends upon consistency with the objectives for a Reference Tariff and Reference Tariff Policy, set out in section 8.1 of the Code. The consistency of the methodology used by Epic Energy with these objectives is addressed in subsequent sections of this Draft Decision in relation to determination of a Total Revenue requirement, and the methodology used by Epic Energy to recover the required Total Revenue.

## 5.3 INITIAL CAPITAL BASE

### 5.3.1 Access Code Requirements

As part of an assessment of the first Access Arrangement for an existing Covered Pipeline, the Regulator is required by the Code to approve a value of the assets making up the pipeline (an Initial Capital Base). The Initial Capital Base is then treated under the Code as an historical cost that is carried forward to future regulatory periods by adjusting for depreciation, new Capital Expenditure and, where appropriate, redundant assets.

Sections 8.10 and 8.11 of the Code state the principles for establishing the Initial Capital Base. These principles apply to the proposed Access Arrangement for the DBNGP.

Section 8.10 of the Code requires that a range of factors be considered in establishing the Initial Capital Base. These factors relate generally to the relative advantages and disadvantages of different valuation techniques, consideration of reasonable expectations and interests of interested parties, and the economically efficient utilisation of gas resources.

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 bounded by the Depreciated Actual Cost (DAC)[51] of pipeline assets and a Depreciated Optimised Replacement Cost (DORC) for the assets.

### 5.3.2 Access Arrangement Proposal

Epic Energy has proposed an Initial Capital Base of $2,570.34 million as at 31 December 1999. This value was derived as follows.[52]

- Summation of the 1998 DBNGP purchase price of $2,407 million and $42.49 million of associated acquisition costs[53] 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.[54]

[51] The term "Depreciated Actual Cost" is here given the meaning of section 8.10(a) of the Code as "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".

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

[53] 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).

[54] The valuation of individual assets was undertaken for Epic Energy by Edward Rushton Australia Pty Limited. Epic Energy 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,

- 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.

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

**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** |

purportedly 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.)

Epic Energy has argued that valuation of the Initial Capital Base on the basis of the purchase price of the assets is appropriate given the circumstances of the purchase. Epic Energy's argument for this position is summarised as follows.

- In the process of purchasing the DBNGP, a set of common understandings and expectations (referred to by Epic Energy as the "regulatory compact") was established between Epic Energy, AlintaGas and the Western Australian State Government as to the future tariffs that would apply for the transportation of gas in the DBNGP and future capital investment to be undertaken to increase the capacity of the DBNGP.
- The purchase price of the DBNGP was offered by Epic Energy on the basis of the common understandings and expectations as to future tariffs.
- Epic Energy has a right to earn a fair return on its investment in the DBNGP, to the extent that this is consistent with the tariff path committed to by Epic Energy during the process of the purchase.
- Epic Energy considers that while the Regulator is not bound by any understandings and expectations surrounding the purchase agreement to establish the Initial Capital Base of the DBNGP on the basis of the purchase price, such a valuation is consistent with the reasonable expectations of Epic Energy given the circumstances of the DBNGP purchase, and is consistent with the required considerations of the Regulator under section 2.24 of the Code and the requirements for a Reference Tariff Policy as set out in section 8 of the Code.

Submissions made by Epic Energy subsequent to lodgement of the proposed Access Arrangement outline the nature of the purported regulatory compact[55] and its relation to derivation of the proposed Initial Capital Base.[56] The derivation of the Initial Capital Base is summarised as follows.

> Epic Energy's determination of the initial capital base
>
> 2.1 Epic Energy has maintained, and continues to maintain, that the gas transmission tariffs, and the path of future tariffs, recorded in Schedule 39 of the DBNGP Asset Sale Agreement, were key elements of the common understandings and expectations between Epic Energy and the Government of Western Australia that developed during the pipeline sale process.[57] Epic Energy has referred to these common understandings and expectations as a regulatory compact. The form of the regulatory compact was established in the Epic First Submission and in Epic Submission 1. This has been supplemented by Epic Submission 3 and Epic Submission 4. Most submissions filed by interested parties suffer from the fact that the authors have not had the opportunity of reading those submissions. Hence a lot of the argument is misdirected through a lack of understanding of the regulatory compact argument or the regulatory model developed by the Brattle Group.
>
> 2.2 For the Government, the tariffs and the tariff path of Schedule 39 were critical policy outcomes from the sale of the DBNGP. Gas transmission tariffs were lowered to a level consistent with the Government's expectations. In addition, the tariffs and the tariff path supported a purchase price for the pipeline that allowed the Government to deliver benefits to the broader community through debt reduction, and through education, health and infrastructure initiatives, funded from the proceeds of pipeline sale.
>
> 2.3 The tariffs and the tariff path of Schedule 39 are linked directly to the price Epic Energy paid for the DBNGP through the assessment of pipeline value made at the time of sale. At the time of pipeline sale, Epic Energy determined, using forecasts of pipeline throughput that had been provided by the Government,

[55] Epic Energy First Submission; Epic Energy Submissions 1, 3, 4 and 5.

[56] Epic Energy Submission 5.

[57] Schedule 39 has been released by AlintaGas, as Appendix 2 to its *Second Submission to Regulator on Epic Energy's DBNGP Access Arrangement*.

> that these tariffs and the tariff path would provide a revenue stream that would support a purchase price of \$2.407 billion.
>
> 2.4 Epic Energy has used a model of regulatory asset valuation proposed by its regulatory adviser, The Brattle Group, to establish the initial capital base for the DBNGP. The Brattle Group's report to Epic Energy on the proposed regulatory model (lodged with the Access Arrangement on 15 December 1999) was released by OffGAR on 20 April 2000, as part of Epic Submission 1.
>
> 2.5 The regulatory model takes the tariffs and tariff path of the regulatory compact as imposing an upper limit on tariffs. Tariffs may not exceed the upper limit imposed by the tariff path. They may, however, fall below that upper limit if increases in demand for gas transportation are expected to result in depreciation charges that recover the investment in the capital base before the pipeline reaches the end of its economic life.
>
> 2.6 Epic Energy believes the tariffs and the tariff path should remain fixed for a period of 20 years from the date of its purchase of the DBNGP. Financial analyses undertaken to support a major acquisition usually use a time horizon of 20 years. A shorter time horizon results in excessive weight being placed on an uncertain residual. A longer time horizon requires specific forecasts for increasingly uncertain events. Financial analyses undertaken by Epic Energy and its financial advisers immediately prior to the sale of the DBNGP used a time horizon of 20 years.
>
> In maintaining its commitment to the regulatory compact, Epic Energy will not seek to change its tariffs and the tariff path for a period of 20 years. Although the Access Arrangement would be reviewed by the Regulator at five years intervals, and changes may be made to the Reference Service to reflect changing market conditions, there would be no change in the tariff or the tariff path resulting from changes in the capital base.
>
> 2.8 With the tariffs to follow a tariff path that is fixed for an extended period, Epic Energy may not recover the capital charges on the initial capital base, and on the capital base in subsequent years, without growth in the demand for gas transportation. Any shortfall in capital recovery is to be treated, in accordance with the regulatory model, as economic depreciation, and added back to the asset base. The use of an economic rather than an accounting concept of depreciation allows postponement of recovery of a part of the capital base until that recovery is warranted by growth in demand for gas transportation services. Higher demand allows Epic Energy to receive higher revenues and recover capital without an increase in the absolute level of tariffs.
>
> 2.9 In adopting the regulatory model proposed by The Brattle Group, Epic Energy is assuming the "volume risk" associated with market growth. If the demand for gas transportation grows in the way expected at the time of the DBNGP sale, Epic Energy will recover the its investment in the pipeline. If the market does not grow as expected, a part of the price paid by Epic Energy for the DBNGP will be shown to have been an imprudent investment for which Epic Energy shareholders will not be compensated.

In summary, Epic Energy has supported the proposed Initial Capital Base by argument that it is consistent with a reasonable purchase price of the assets given, *inter alia*, the tariffs and tariff path specified in Schedule 39 of the DBNGP Asset Sale Agreement, forecasts of future quantities of gas to be transported through the DBNGP, and the regulatory model underlying the proposed Access Arrangement, particularly as it relates to the recovery of capital by deferred depreciation.

Epic Energy has supported the argument for the determination of the Initial Capital Base by reference to implicit regulatory compacts between regulators and regulated firms in the United States and the United Kingdom, and similar mechanisms for valuation of utility assets (on the basis of purchase prices) in the United Kingdom and of airport assets in New Zealand.[58]

Epic Energy has also supported the proposed valuation of the Initial Capital Base with illustrative calculations indicating that the purchase price of the DBNGP is justified by consistency with the net present value of cash flows given the future tariffs proposed at the

[58] Carpenter, P., Lapuerta, C. and Moselle, B., 2000. Regulatory Compact and Asset Values after Privatisation: a Discussion Paper, August 2000, Public Version, paper prepared for Epic Energy, The Brattle Group.

time of the purchase, and a recovery of the invested capital over the physical life of the assets at the same future tariffs. The following information was provided by Epic Energy to indicate that a purchase price of $2,450 million is consistent with a net present value of expected cash flows over a ten-year period.[59] Epic Energy stated that this calculation is a simplification of the method used by Epic Energy to derive the sale price during the sale process.[60]

**Epic Energy modelled net present value of cash flows from the DBNGP assets**

| | | Year | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Volume ($\times 10^6$ GJ) | | 325 | 350 | 375 | 400 | 450 | 500 | 500 | 500 | 500 | 500 |
| Tariff ($/GJ) | 1.05 | | | | | | | | | | |
| Revenue ($million) | | 341 | 368 | 394 | 420 | 473 | 525 | 525 | 525 | 525 | 525 |
| Non-capital costs ($million) | | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Cost of capital | 10% | | | | | | | | | | |
| PV revenue ($ million) | 2,726 | | | | | | | | | | |
| PV costs ($ million) | 246 | | | | | | | | | | |
| NPV ($ million) | 2,480 | | | | | | | | | | |

The above calculation of the net present value of cash flows assumed forecast increases in gas transportation volumes contemplated by Epic Energy at the time of the purchase, a constant tariff of $1.05/GJ (in nominal terms), constant non-capital costs (in nominal terms), zero capital costs, and a discount rate equal to a nominal pre-tax cost of capital of 10 percent.

In a variation on this calculation, Epic Energy also supported the proposed valuation of the Initial Capital Base with a demonstration that the purchase price of the DBNGP is consistent with the recovery of the capital investment over a ten year period, a constant tariff of $1.05/GJ, the forecast increase in throughput and the proposed methods of economic depreciation and deferred asset recovery, as follows.[61,62]

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[59] KPMG Consulting Pty Ltd, 16 October 2000. Dampier to Bunbury Natural Gas Pipeline: Basis of Reference Tariff Determination, Attachment 1 to Epic Energy Additional Paper 5: Code Compliance, 25 October 2000, p 11.

[60] In its Additional Paper 5, Epic Energy indicated "*the asset valuation sheets of KPMG Consulting's spreadsheet model are very simple versions of the financial model developed to support Epic Energy's purchase of the DBNGP. … The asset valuation sheets illustrate determination of the price Epic Energy paid for the pipeline given the forecast of gas volumes transported derived from information in the sale Information memorandum, and given the tariffs the Government of Western Australia was seeking at the time of pipeline sale. … The figures used in the asset valuation sheets, and in the sheets which follow, have no direct relationship with the figures used in the actual models developed to support Epic Energy's purchase of the DBNGP, and in models used for determining the proposed DBNGP reference tariff. All of the figures used have, wherever possible, been chosen to ensure the simplicity of the illustrations.*"

[61] Refer to section 5.6.1 of this report for details of the proposed depreciation schedule.

[62] KPMG Consulting Pty Ltd, 16 October 2000. Dampier to Bunbury Natural Gas Pipeline: Basis of Reference Tariff Determination, Attachment 1 to Epic Energy Additional Paper 5: Code Compliance, 25 October 2000, p 14.

**Epic Energy modelled capital recovery for the DBNGP**

| | | Year | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Volume ($\times 10^6$ GJ) | | 325 | 350 | 375 | 400 | 450 | 500 | 500 | 500 | 500 | 500 |
| Tariff ($/GJ) | 1.05 | | | | | | | | | | |
| Revenue ($million) | | 341 | 368 | 394 | 420 | 473 | 525 | 525 | 525 | 525 | 525 |
| **Beginning of year balances ($million)** | | | | | | | | | | | |
| Physical asset account | | 2,480 | 2,232 | 1,984 | 1,736 | 1,488 | 1,240 | 992 | 774 | 496 | 248 |
| Deferred recovery account | | 0 | 195 | 358 | 486 | 577 | 599 | 545 | 462 | 346 | 193 |
| Capital base | | 2,480 | 2,427 | 2,342 | 2,222 | 2,065 | 1,839 | 1,537 | 1,206 | 842 | 441 |
| Cost of capital | 10% | | | | | | | | | | |
| Return on capital ($million) | | 248 | 243 | 234 | 222 | 206 | 184 | 154 | 121 | 84 | 44 |
| Depreciation ($million) | | 248 | 248 | 248 | 248 | 248 | 248 | 248 | 248 | 248 | 248 |
| Non-capital costs ($million) | | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Depreciation of deferred recovery account ($ million) | | -195 | -163 | -128 | -90 | -22 | 53 | 83 | 116 | 153 | 193 |
| **End of year balances ($million)** | | | | | | | | | | | |
| Physical asset account | | 2,232 | 1,984 | 1,736 | 1,488 | 1,240 | 992 | 774 | 496 | 248 | 0 |
| Deferred recovery account | | 195 | 358 | 486 | 577 | 599 | 545 | 462 | 346 | 193 | 0 |
| Capital base | | 2,427 | 2,342 | 2,222 | 2,065 | 1,839 | 1,537 | 1,206 | 842 | 441 | 0 |

### 5.3.3 Submissions from Interested Parties

#### 5.3.3.1 Overview of Submissions

Public submissions on the proposed Access Arrangement addressed the following issues in respect of valuation of the Initial Capital Base.

- Requirements for Epic Energy to provide Depreciated Actual Cost (DAC) and Depreciated Optimised Replacement Cost (DORC) valuations of the DBNGP.
- Valuation of the Initial Capital Base at the cost of purchase of assets and outside the range of DAC and DORC.
- The magnitude of the Initial Capital Base.
- Alternative valuation methodologies for the Initial Capital Base.
- The Initial Capital Base as a Fixed Principle.

In view of the number and length of submissions on issues relating to the Initial Capital Base, the comments made in submissions are summarised below together with the Regulator's responses. The Regulator's deliberations in respect of the Initial Capital Base are detailed in section 5.3.4 of this Draft Decision.

#### 5.3.3.2 Provision of DAC and DORC Valuations

**Submissions**

Paragraphs 8.10(a) and 8.10(b) of the Code require, in establishing the Initial Capital Base for a pipeline that was in existence at the commencement of the Code, consideration of valuations of the Initial Capital Base that would be derived by two particular methodologies:

(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.

For the purposes of this Draft Decision, a valuation in accordance with paragraph 8.10(a) of the Code is referred to as a Depreciated Actual Cost (DAC) value.

In the proposed Access Arrangement documentation originally submitted to the Regulator on 15 December 1999, Epic Energy did not provide DAC or depreciated optimised replacement cost (DORC) valuations of the DBNGP determined in accordance with these sections of the Code. Several submissions drew attention to the absence of information on these valuations in the proposed Access Arrangement documents, and some of these submissions called for the Regulator to require Epic Energy to submit this information for consideration in assessment of the proposed Access Arrangement and for the valuations to be independently verified.[63] The reasons outlined in the submissions for the Regulator to impose such a requirement were as follows.

- Section 8.11 of the Code indicates that the Initial Capital Base for a pipeline in existence at the commencement of the Code should not normally fall outside of the range of values of paragraphs 8.10(a) (DAC) and 8.10(b) (DORC) of the Code. Under section 2.6 of the Code, the Access Arrangement Information must contain such information as the Regulator considers would enable Users and Prospective Users to form an opinion as to the proposed Access Arrangement's compliance with the Code. The view was expressed in submissions that it would be impossible for the Regulator or any other person to form an opinion as to whether the Access Arrangement, in particular the proposed Initial Capital Base, complies with sections 8.10 and 8.11 of the Code, unless the Access Arrangement Information includes DAC and DORC values and supporting information.[64]
- Under section 2.7 of the Code, the Access Arrangement Information must include the material set out in Attachment A to the Code, which under Category 2 includes information as to asset valuation methodologies, historical cost or asset valuation. No such information is provided in the AAI.[65]

Submissions also indicated expectations of the DAC and DORC values of the DBNGP.

Submissions cited AlintaGas's Annual Report for the year to 30 June 1997 that indicated a book value of property, plant and equipment for AlintaGas's transmission business (then

[63] Submissions from Worsley Alumina, Hamersley Iron, AGL (Submission 2), Energy Markets Reform Forum, WMC, Western Power (Submission 3), AlintaGas (Submissions 1, 3), North West Shelf Gas, Bunbury Wellington Economic Alliance, CMS, Robe River Mining Pty Ltd, Treasury/Office of Energy, Wesfarmers, South West Development Commission, Cockburn Cement, Apache Energy Limited.

[64] AlintaGas Submission 1.

[65] AlintaGas Submission 1.

including the DBNGP) of $937 million, resulting in an expectation that the DAC value of the DBNGP would be less than $1 billion.[66]

WMC indicated an expectation, on the basis of experience in construction of gas pipelines including the Goldfields Gas Pipeline, that the DORC value is unlikely to exceed $1,100 million to $1,200 million. AlintaGas indicated an expectation that the DORC value for the pipeline would be in the range of $0.8 billion to $1 billion, and supported this view with an indication that such a value is consistent with unit pipeline costs used by Epic Energy to estimate a DORC value for its Moomba to Adelaide Pipeline, and the cited cost of doubling the capacity of the DBNGP.[67]

Submissions from Wesfarmers and the Chamber of Minerals and Energy also indicated an expectation that the DAC and DORC values should be in the order of $1 billion.

In its submission number 3, Epic Energy indicated a view that neither a DAC nor a DORC valuation of the DBNGP is required to be stated in the Access Arrangement Information as such information is not necessary for understanding the proposed Access Arrangement and the proposed Reference Tariff. Epic Energy indicated that it strongly maintains:

- understanding the reference tariff and other elements of the DBNGP Access Arrangement does not require knowledge of DAC and DORC valuations for the Pipeline; indeed, knowledge of those values could mislead a party seeking to understand, and rely on, the proposed reference tariff as they are not relevant in any way to the derivation of the tariff;
- knowledge of the DAC and DORC valuations is not required to form an opinion as to compliance of the Access Arrangement Information with the provisions of the Code; and
- Epic Energy has provided, in the Access Arrangement Information, all of the information that the Code requires be provided to assist users and prospective users understand the proposed Access Arrangement and, in particular, the derivation of the reference tariff.

In the Access Arrangement Information submitted to the Regulator on 15 December 1999, Epic Energy indicated that:

> Section 8.11 of the Code provides bounds within which the Initial Capital Base for an existing pipeline should "normally occur". However the Code does not make these bounds mandatory, and in fact, in section 8.10 prescribes a number of other factors to be taken into account in setting the Initial Capital Base. The competitive bidding process through which Epic Energy acquired the DBNGP removed the Initial Capital Base from within the indicative bounds of section 8.11 of the Code.

### Regulator's Response to Submissions

Notwithstanding the stated position of Epic Energy in respect of providing information on DAC and DORC valuations, the Regulator on 7 July 2000 required Epic Energy, in accordance with section 2.9 of the Code, to resubmit the Access Arrangement Information with the inclusion of valuations of the DBNGP under paragraph 8.10(a) and 8.10(b) of the Code, being DAC and DORC values, respectively. Epic Energy provided DAC and DORC valuations for the DBNGP ($2,466.1 million and $1368.4 million, respectively) in a revised Access Arrangement Information submitted to the Regulator on 28 July 2000. These valuations are discussed in section 5.3.4 of this Draft Decision.

[66] AlintaGas Submissions 1, 3.
[67] AlintaGas Submissions 1, 3, 4.

#### 5.3.3.3 Valuation at Cost of Purchase

**Submissions**

The Initial Capital Base proposed by Epic Energy of $2,570.34 million as at 31 December 1999 was based on the costs of purchase by Epic Energy of the DBNGP assets and was noted in several submissions to be greater than supposed DAC and DORC values. Several submissions expressed the view that the Initial Capital Base should not fall outside (and above) the range of DAC and DORC. Submissions also expressed the view that the magnitude of the Initial Capital Base should not be in excess of DORC and that the purchase price should not be used as the basis for valuation.

The Australian Gas Users Group advocated the use of a DAC valuation due to the fundamental advantage of being a single, accurate and verifiable figure, as opposed to a DORC valuation, expressing the view that the methodology is "seriously flawed and discredited".

Many submissions made on the proposed Access Arrangement indicated that the proposed Initial Capital Base, based on acquisition costs, is in excess of the range of values between DAC and DORC and indicated a view that such a valuation may be contrary to section 8.11 of the Code.[68] Section 8.11 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 (the DAC and DORC values, respectively).

The view was also expressed in some submissions that the cost of acquisition of the DBNGP by Epic Energy should not be the basis for the Initial Capital Base,[69] and that the emergence of the sale price from a competitive bidding process is not due cause, as submitted by Epic Energy,[70] for the limits on the value of the Initial Capital Base set in section 8.11 of the Code to not apply.[71] There were three general arguments presented in support of this view.

i. There is no regulatory compact as alleged by Epic Energy that deals with tariffs or a tariff setting methodology, and which may give rise to an Initial Capital Base equal to the purchase costs. Moreover, even if there was a regulatory compact any such compact could not be binding on the Regulator.[72]

ii. The circumstances of the sale of the DBNGP are not sufficiently "abnormal" to justify a value of the Initial Capital Base outside of limits of section 8.11 of the Code.[73]

iii. Regardless of the valuation of the Initial Capital Base relative to DAC and DORC valuations, valuation on the basis of the purchase price is inappropriate as such a valuation is inappropriate for the valuation of physical assets.

These arguments are outlined in more detail as follows.

AlintaGas has indicated that there is no regulatory compact as alleged by Epic Energy and that neither itself nor the State made any agreements as to the tariffs that may apply after the

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[68] Australian Gas Users Group, Chamber of Commerce and Industry, Wesfarmers, WMC, Mark Neville MLC, AGL.

[69] WMC, South West Development Commission.

[70] Access Arrangement Information, 28 July 2000, p31.

[71] Chamber of Minerals and Energy, AlintaGas Submission 3.

[72] AlintaGas Submissions 3, 4.

[73] AlintaGas Submission 3.

sale, nor for Epic Energy to use the DBNGP purchase price as the Initial Capital Base under the Code, or any other Capital Base.[74] Furthermore, AlintaGas has suggested that a regulatory compact, as envisaged within United States jurisdictions as a statement of the rights and obligations of a utility and the public, is simply the process of regulation embodied by application of the Code. However, AlintaGas submitted that:[75]

> " … the Regulator should ignore any inference by Epic Energy that a "regulatory compact", as Epic Energy utilises the term, is accepted practice in the United States. In any event the practice in the United States is irrelevant in the context of the National Access Code, which Epic Energy knew was to be applied to the DBNGP at the time Epic Energy purchased the DBNGP …."

AlintaGas submitted that although Schedule 39 of the DBNGP Asset Sale Agreement sets out tariffs for services, this comprises only a warranty given by Epic Energy as to tariffs it then proposed to implement, and further that it could make an acceptable return at those tariffs.[76] That is, neither the State nor AlintaGas gave any undertaking to accept the tariffs as proposed, and there could be no such undertaking given by the State or AlintaGas since the determination of tariffs under the National Access Code is outside the State's or AlintaGas's control. Schedule 39 was a contractual representation by Epic Energy to AlintaGas of its then proposed tariff rates and path, and the fact that it felt that those rates and path (for a T1 equivalent Reference Service) would be profitable – Schedule 39 is in no way evidence of a "regulatory compact". Moreover, AlintaGas indicated that it is in no way bound to accept the tariffs and tariff path in Schedule 39; it was and is at liberty to seek lower and different tariffs, if such tariffs are consistent with the National Access Code, and that this fact was clearly communicated to Epic Energy at the time of the DBNGP sale.[77] The submission from Treasury/Office of Energy indicated a similar position:

> "In the sale process there was no other agreement between the vendor and the bidder, and no other obligation placed on the bidder by the vendor, or the State, in respect of tariff rates for gas transmission or a tariff path for third party use of the DBNGP. The sole right of the vendor with respect of the proposed tariff rates and path indicated to it by the bidder is to have discretion to disclose to the Regulator those tariff rates and path as being those proposed by the bidder at the time of the sale. The effect of such disclosure continues to be viewed by the State, as providing an indication of the maximum tariff rates for gas transmission, which the bidder might be able to sustain in a regulatory process conducted by an independent Regulator. Nothing in that Agreement is viewed by the State as creating a binding obligation on the Regulator or any form of regulatory compact between the State and Epic Energy in relation to tariffs for third party use of the DBNGP."

AlintaGas indicated that, by virtue of the information provided to Epic Energy and other bidders as part of the sale process, wide publicity of the Code during its drafting, and signing of the *Natural Gas Pipelines Access Agreement* before bids for the DBNGP were finalised, Epic Energy would have had full knowledge that after 1 January 2000 Reference Tariffs would be determined as part of an Access Arrangement consistent with the Code and approved by the Regulator.[78] In particular, AlintaGas submitted that prior to making its bid, Epic Energy was aware that:

- under the then draft National Access Code the pipeline operator would have to calculate Reference Tariffs in accordance with detailed principles relating to matters including asset valuation, apportionment of costs, depreciation and incentive mechanisms;

[74] AlintaGas Submission 4.

[75] AlintaGas Submission 4.

[76] AlintaGas Submission 4.

[77] AlintaGas Submission 4.

[78] AlintaGas Submission 4.

- the Regulator would have considerable discretion in determining whether to approve a Reference Tariff or a Reference Tariff Policy;
- Reference Tariff levels for transmission services to be provided by the DBNGP following the Transition Period were to be based upon Access Code principles that provided for a reasonable rate of return on the capital base of the pipeline's various assets;
- the Gas Pipeline Sale Steering Committee had, for its own purposes, commissioned an independent indicative valuation for the DBNGP Assets, consistent with National Access Code principles, for the purpose of considering possible future tariff paths for the services provided by the DBNGP;
- the independent indicative valuation suggested that a supportable capital base for the DBNGP Assets, being a DORC valuation consistent with the National Access Code principles, was in the order of $1,124 million as at 31 December 1997; and
- determination of a DORC valuation may be undertaken in different ways, which could give different values to the estimate of $1,124 million.

In response to the submissions by AlintaGas and Treasury/Office of Energy, Epic Energy indicated a total rejection of the view that there was no regulatory compact, reiterating that the alleged regulatory compact related to common understandings and expectations rather than any formal agreement:

> Epic Energy has never claimed that the regulatory compact was more than a set of common understandings and expectations. Epic Energy has not asserted, in the DBNGP Access Arrangement, in the Access Arrangement Information, or in any of the other documents it has submitted to the Regulator, that the regulatory compact was, in any sense, an agreement legally binding on the parties. Epic Energy is in agreement with the view expressed by the Treasury and the Office of Energy that there was no agreement, other then the DBNGP Asset Sale Agreement in respect of gas transmission tariffs and the tariff path.[79]

Epic Energy also submitted that it has not sought to justify the proposed Initial Capital Base for the DBNGP in terms of the Initial Capital Base being part of the regulatory compact.[80] Epic Energy does, however, refer to the regulatory compact in justification for the proposed Initial Capital Base.

> Epic Energy has argued, and will continue to argue, that the Regulator should give consideration to the common understandings and expectations, referred to by Epic Energy as the regulatory compact, in assessing the proposed DBNGP Access Arrangement. In particular, the Regulator should give consideration to the regulatory compact in assessing the way in which Epic Energy has established the initial capital base for the pipeline in accordance with section 8.10 of the *National Code for Third Party Access to Natural Gas Pipeline Systems* (the Code). Obligations on the Regulator to do so derive, not from the regulatory compact, but from section 2.24 and section 8 of the Code. Epic Energy acknowledges the view of AlintaGas that the regulatory compact is not binding on the Regulator, and concurs with the view of the Treasury and the Office of Energy that the Asset Sale Agreement did not create any binding obligation on the Regulator. However, then again they could not. This is not an issue of what is binding, but what is appropriate to apply given the circumstances in which Epic Energy acquired the DBNGP and its conduct since in respect of those circumstances.[81]

In arguing that the valuation of the Initial Capital Base should be in the range of DAC and DORC, AlintaGas drew attention to section 7.13 of the Code that sets out the information that must be provided to the Code Registrar by the Regulator in respect of a decision in relation to an Access Arrangement, particularly in respect of the valuation of the Initial Capital Base.[82] AlintaGas indicated that the requirement under paragraph 7.13(a)(iii) of the Code for detailed reasons supporting any valuation outside of the range of DAC and DORC suggests that such an outcome is expected to be an abnormal event requiring special justification. AlintaGas

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[79] Epic Energy Submission 4, paragraph 4.10.
[80] Epic Energy Submission 4, paragraph 4.11.
[81] Epic Energy Submission 4, paragraph 4.12.
[82] AlintaGas Submission 3.

submitted that there is nothing in Epic Energy's Access Arrangement Information, and nothing in the factual circumstances of the DBNGP sale itself, which are sufficiently abnormal to justify departure from the DAC/DORC range. Similarly, Worsley Alumina submitted that it had obtained legal advice to the effect that the assertion that the competitive bidding process through which Epic Energy acquired the DBNGP removed the Initial Capital Base from within the indicative bounds of section 8.11 of the Code is not correct in law and that the Initial Capital Base should lie in the range bounded by DAC and DORC.

Epic Energy has indicated that the situation of the DBNGP is not normal within the scope of section 8.11 of the Code by virtue of the content and background of the regulatory compact, and also the potential applicability of Reference Tariffs under the Access Arrangement to existing gas transportation contracts:

> What makes this situation even more unique, and the regulatory compact more powerful, is the fact that, unlike any pipeline that has had to file an Access Arrangement under the Code, due to [section] 20 of the *Dampier to Bunbury Pipeline Act 1997* and the provisions contained in the standard contracts entered into after the DBNGP was purchased,[83] there was the potentiality for the significant majority of existing transport contracts moving to the Reference Tariff or a tariff derived from the Reference Tariff. In all other Access Arrangements, the existing contracts have remained on their existing terms including tariffs. Hence, in the case of the DBNGP, the move to a tariff under an approved Access Arrangement was far more significant. To effect the sale of the DBNGP, the Government had to structure the sale to give far greater certainty to prospective buyers of the Pipeline. In structuring the sale, the Government began setting in place the elements of the regulatory compact.[84]

Submissions also indicated the view that while the Code does make allowance for the value of a Covered Pipeline to be established by a competitive bidding process,[85] this applies only to pipelines that have not been built at the time the competitive bidding process is undertaken,[86] and there is no obligation on the Regulator to accept the purchase price as the basis for valuation.[87] It was submitted that it is absurd to suggest or imply that sections 3.21 to 3.36 of the Code (relating to determination of Reference Tariffs through a competitive bidding process) are relevant.[88] The argument presented in this regard is that the tender process contemplated by those sections of the Code and the sale process undertaken for the DBNGP are directed at entirely different objectives. When a pipeline is yet to be constructed, which is the circumstance contemplated by sections 3.21 to 3.36, the project proponent will (all else being equal) seek to minimise the cost. In contrast, when a pipeline is being sold, one of the objectives of the vendor will be to maximise the price realised. Furthermore, it was submitted that even if the Regulator accepted that the bidding process was confirmed to be fully compliant with section 3 of the Code, section 3 would still require the Regulator to satisfy himself that an Initial Capital Base equal to the DBNGP acquisition costs would deliver the lowest sustainable tariffs to users over the proposed economic life of the pipeline.[89]

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[83] See clause 93 of the schedule to the DBNGP Access Manual under the Dampier to Bunbury Pipeline Act 1997.

[84] Epic Energy Additional Paper 5: Code Compliance, section 3.19.

[85] Code section 3.21 et seq. Section 3.21 of the Code provides for a tender process to be used to determine Reference Tariffs for certain Reference Services to be provided by means of a proposed pipeline, and other specified items which are required to be included in an Access Arrangement and which are directly relevant to the determination of the Reference Tariffs concerned. The latter would include an Initial Capital Base.

[86] Chamber of Minerals and Energy, AlintaGas Submission 3.

[87] Mark Neville MLC, Energy Markets Reform Forum.

[88] AlintaGas Submission 3.

[89] Treasury/Office of Energy. The Regulator infers that this submission refers to section 3.28(f) of the Code.

Regardless of the valuation of the Initial Capital Base relative to DAC and DORC valuations, submissions on the proposed Access Arrangement indicated in-principle opposition to valuation of the DBNGP at the cost of purchase. Reasons for this opposition were as follows:

- The purchase price took into account forecasts of substantial increases in gas throughput that may not eventuate.
- The purchase price would have incorporated the value of intangible assets and other price premia that should not be included in the valuation of the Initial Capital Base.
- Valuing the Initial Capital Base at the purchase price shifts to Users a commercial risk that the purchaser may have erred in determining a purchase price and thus paid a higher price than was reasonable or prudent for the assets.
- While "the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase" should be considered in establishing the value for the Initial Capital Base" (paragraph 8.10(j) of the Code), this may refer to peripheral assets of the pipeline system rather than the pipeline itself.
- The determination of the Initial Capital Base on the basis of purchase price gives rise to an undesirable precedent in asset valuation, potentially giving rise to a spiralling of asset values and tariffs.

Submissions on these matters are summarised below.

<u>Forecasts of Gas Throughput</u>

Some submissions expressed a view that the purchase price of the DBNGP was based upon projections of future increases in gas throughput that may not eventuate, in which case an Initial Capital Base may have been set at too high a level with a consequently higher Reference Tariff either now or sometime in the future.[90] The submissions indicated that the purchase price should be assessed to determine the extent to which it provides a reasonable asset valuation (in terms of a purchase price) given uncertainty over future throughput.

Treasury/Office of Energy indicated an immediate example of forecast throughput failing to materialise in the delayed development of the Mid West Iron and Steel Project that would have resulted in a substantial (170 TJ/day) increase in throughput for part of the pipeline.

WMC indicated a view that "acquisition premiums" are not allowable under the Gas Code and that the Regulator should not accept a pipeline valuation that is predicated on throughput assumptions in excess of current levels unless Epic bears the risk associated with this demand not materialising, consistent with the approach of the Regulator in the Draft Decision on the proposed Access Arrangement for the Parmelia Pipeline.

Epic Energy responded to these submissions indicating that under the proposed regulatory model, Epic Energy would not be able, due to the fixed tariff path, to recover any premium in the purchase price that was associated with excessively optimistic volume forecasts.[91]

<u>Intangible Assets</u>

Several submissions indicated a view that the purchase price for the DBNGP would or may have included premia above the value directly attributable to the physical assets. Price premia may be attributable to intangibles such as business goodwill, and complementarities

[90] Robe River Mining, Treasury/Office of Energy, Wesfarmers, AlintaGas Submission 3.

[91] Epic Energy Submission 5 Appendix 1 section 1.4.

and synergies with other business activities or opportunities.[92] The view was expressed that these premia should not be reflected in the Initial Capital Base.

AlintaGas indicated the range of factors that may give rise to price premia above a value attributable to physical assets.[93]

> "The purchase price of $2.407 billion paid by Epic Energy for the DBNGP was presumably the subjective value of the asset to Epic Energy in March 1998. The purchase price would have been only partly dependent on future revenue potential from existing users of the DBNGP. Factors that might have influenced Epic Energy to bid more for the DBNGP than the economic value of future cash flows from existing users include:
>
> – Strategic benefits and growth potential. The DBNGP, being one of the most significant infrastructure assets in Western Australia, is a strategically important asset with strong growth potential and limited downside risk.
>
>   The Australian Infrastructure Fund ("AIF"), which is managed by Hastings Fund Management Limited ("Hastings"), and is a 4% part owner of the Epic Energy entities and therefore the DBNGP, had a similar opinion. For example, AIF's 1998 Annual Report states:
>
>   "AIF acquired an interest in the highly strategic Dampier-Bunbury Natural Gas Pipeline."
>
>   "Given the vast gas reserves of the North West Shelf, WA's strong economic growth rate and the number of projects being considered in the energy intensive resources processing industry, Hastings believes this to be the premier gas transmission asset in Australia."
>
>   and,
>
>   "DBNGP is one of the most rapidly growing infrastructure assets in Australia and is strategically important to the economy of the state of Western Australia."
>
>   This view is supported in an Information Memorandum prepared by Hastings and released on 28 May 1998, where it is stated that:
>
>   "The DBNGP provides AIX[94] investors with access to the strong growth expected to occur in the WA market and an attractive yield from existing contracts with major users including Alcoa and AlintaGas."
>
>   and,
>
>   "A stake in the DBNGP is attractive to AIX for several strategic reasons:
>
>   …
>
>   its downside is protected by long-term 'take-or-pay' contracts;
>
>   …
>
>   offers limited competitive threat due to high capital costs for new entrants and existence of major gas purchase contracts."
>
> – Epic Energy may have perceived a lower risk for its investment in the DBNGP whilst anticipating a return for the DBNGP under section 8 of the National Access Code that assumes a higher risk.
>
> – Epic Energy may have expected to benefit from jurisdictional taxation arbitrage – namely the marginal tax benefit that can be obtained through the use of different tax jurisdictions – in its acquisition of the DBNGP.
>
> – Epic Energy may have perceived synergies between the DBNGP and its existing Australian assets.
>
> – Epic Energy may have expected to outperform the benchmarks used to set regulated tariffs."

AlintaGas expressed a view that the purchase price of a pipeline system is not appropriate as the value of the Initial Capital Base is inconsistent with current regulatory thinking in

[92] Bunbury Wellington Economic Alliance, Worsley Alumina, WMC, AlintaGas Submission 3.

[93] AlintaGas Submission 3.

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

Australia. In support of this stance, AlintaGas cited examples of other regulatory decisions and asset sales, as follows.[95]

- IPART determined an initial Capital Base for Great Southern Energy's Wagga Wagga Gas Distribution System that fell between the DAC and DORC valuations, stating:[96]

  > … the Tribunal is of the view that the initial capital base should not normally be equated to the purchase price of the business. It is of the view that any apportionment of intangible assets to the network business should normally be excluded from the Initial Capital Base.

- In its final decision concerning the Transmission Pipelines Australia Victorian assets on 6 October 1998, the ACCC assessed the various factors that are to be considered under the National Access Code when determining an Initial Capital Base. The ACCC concluded that the valuation should not be in excess of the DORC valuation.
- The view that bidders place a greater value on a pipeline than the Initial Capital Base is supported through consideration of the Victorian transmission pipeline assets. These assets had initial Capital Bases determined in accordance with the principles of the National Access Code prior to their sale, yet purchasers were prepared to pay more than two times the initial Capital Base in order to acquire the assets.

In a submission responding to matters raised by AlintaGas, Epic Energy made the following comments.[97]

> Epic Energy acknowledges that, in determining its Final Bid price for the DBNGP, it made allowance for revenues it would receive from future growth in gas transportation demand if forecasts of pipeline throughput provided by the Government at the time of sale were realised. Epic Energy also made allowances for the additional capital costs that it would expect to incur, and the additional operating and maintenance costs. The purchase price of $2.407 billion Epic Energy paid for the DBNGP was determined after considering both the future revenue potential from existing users of the pipeline, and the revenue that would be generated from potential users whose gas transportation requirements could be anticipated during 1997 and early in 1998. In this respect, Epic Energy's approach to determining the price it paid for the DBNGP followed normal business practice.
>
> Epic Energy's bid price recognised the expected economic value of future cash flows from existing users, and it recognised the expected economic value of cash flows from potential users. Epic Energy's bid price was, in consequence, higher than a bid price that recognised only the expected economic value of future cash flows from existing users. In using the price it paid for the DBNGP as the initial capital base, Epic Energy concedes that it has used a capital base which is "inflated" relative to the capital base that would result from a calculation designed to produce a lower number. Epic Energy also concedes that it has taken into account factors which are, on AlintaGas definition, strategic factors.

Epic Energy also made the following comments.[98]

> AlintaGas speculates that the purchase price was supported by some value other than the "revenue potential from existing users of the DBNGP" (p.9). AlintaGas concludes that the purchase price is therefore irrelevant.
>
> Under a different set of circumstances, AlintaGas might have a point. For example, imagine absurdly that the purchase price was supported by the prospect of using the pipeline rights-of-way for some entirely unrelated business such as building casinos, and that incorporating the entire purchase price in the rate base would therefore allow Epic to recover part of its purchase price twice. That is, the value of the casinos would be collected once by operating the casinos themselves, and a second time by collecting higher revenues from natural gas users. Clearly this would be a problem (and sometimes we see it in cases like

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[95] AlintaGas Submission 3.

[96] Access Arrangement Information for the Great Southern Energy Wagga Wagga Gas Distribution System drafted and approved by IPART, September 1999, p 17.

[97] Epic Energy Submission 5, paragraphs 3.9, 3.10.

[98] Epic Energy Submission 5 Appendix 1 section 2.1.

airports with very profitable duty-free concessions that are only tangentially related to providing monopoly services to airlines), but similar facts are not present in this case. Key distinctions are:

> Epic will not be using the pipeline assets for anything other than transporting natural gas. The quotes that AlintaGas has highlighted from the Australian Infrastructure Fund (p. 9) are entirely irrelevant because they do not describe the attractiveness of the DBNGP for any business other than natural gas transportation. Some of the quotes are also not understandable, such as "its downside is protected by long-term 'take-or-pay' contracts." What contracts does this refer to?
>
> Epic is not trying to use the rate-base to produce higher tariffs than might have been expected when the Western Australian Government selected its winning bid. Rather, our proposal simply provides that Epic's rates will not fall *below* the Schedule 39 tariffs until it becomes clear that the purchase price will be recovered. Our proposal sticks to the tariff schedule that was explicitly stated in a competitive tender process.

<u>Commercial Risk</u>

Several submissions indicated a view that valuation of the Initial Capital Base for the DBNGP at the cost of purchase would have the effect of making Users, and ultimately gas consumers, bear the risk and consequences (through higher gas transportation tariffs) of an imprudent purchase price.[99] AlintaGas made the following comments.[100]

> In a competitive tender process, each bidder will make its own assessment of what to bid for the asset. Logically, the prices bid by different tenderers will be different, even though those bids are based on the same information. The fact that a vendor selects one bid over the rest, does not necessarily indicate that the successful bidder's assessment of the value of the asset is correct or is a value consistent with sections 8.1 and 8.10 of the National Access Code. For this reason, although a recent sale price is a factor which the Regulator can appropriately consider in setting the initial Capital Base, AlintaGas submits that the National Access Code sets the right balance when it gives primacy to the DAC and DORC valuation methods.
>
> …
>
> The sale of a regulated asset poses risks for bidders, as they seek to bid prices high enough to secure the asset, but low enough to generate a sustainable return in the regulated Reference Tariff environment after the asset's sale. In a nutshell, if a purchase price of $2.4 billion cannot be sustained at a tariff regulated in accordance with the National Access Code, then Epic Energy may have paid too much for the pipeline. Be that as it may, Epic Energy cannot now ask existing and future users to underwrite that over-expenditure through higher tariffs derived from an inflated initial Capital Base. This is so regardless of whether that underwriting arises by users paying the same tariff for a degraded service, or through notionally "deferring" the Capital Base until tariffs can be increased. Epic Energy has included both mechanisms in its proposed Access Arrangement.

In response to the submission by AlintaGas, Epic Energy indicated that:[101]

> AlintaGas appears to be arguing that, because the prices bid in a competitive bidding process will usually differ, an accepted bid price in a recent sale is a factor which the Regulator might appropriately consider in setting the initial capital base. However, they go on to say that in giving consideration to a bid price, the Regulator should be guided by the fact that, in AlintaGas's view, the *National Third Party Access Code for Natural Gas Pipeline Systems* gives primacy to DAC and DORC valuations in establishing the initial capital base. For the reasons set out in the Epic First Submission and in Epic Submission 1, Epic Energy does not agree with AlintaGas's view.

and also:[102]

> AlintaGas asserts the inherent risks of bidding for assets, and asserts Epic Energy may have paid too much for the pipeline. Be that as it may, Epic Energy cannot now ask existing and future users to underwrite that over-expenditure through higher tariffs derived from an inflated initial Capital Base.

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[99] Mark Neville MLC, South West Development Commission, Cockburn Cement, Apache Energy Limited, North West Shelf Gas.

[100] AlintaGas Submission 3.

[101] Epic Energy Submission 5, paragraph 3.6.

[102] Epic Energy Submission 5 Appendix 1 section 2.5.

> AlintaGas ignores that existing and future users would in no way "underwrite" the purchase price, because Epic would remain entirely at risk if anticipated future volumes did not materialise.

Scope of Paragraph 8.10(j) of the Code

North West Shelf Gas[103] and Robe River Mining both queried whether paragraph 8.10(j) of the Code would relate to consideration of the purchase price of the total pipeline assets, or alternatively is intended to relate only to peripheral assets of the pipeline system. The argument is stated by North West Shelf Gas as follows.

> To justify their selection of the purchase price as the Initial Capital Base, Epic Energy appear to have relied upon paragraph 8.10(j) of the Code where the use of the purchase price of 'assets' for determining the Initial Capital Base is referred to. If one notes that paragraph 8.10(j) refers to 'assets' with a small 'a', it might therefore be suggested that the term 'asset' used in paragraph 8.10(j) may not have been intended to cover the 'Pipeline' which is a defined term in the Code referring to the 'Pipeline' to be covered by the Code and the third party access arrangements. One could argue that the intent of paragraph 8.10(j) is intended to refer to the recent acquisition (relative to the time of submission of the proposed AA) of pipeline 'assets' of different classes such as buildings, vehicles, compressors, laterals etc and was not intended to refer to the entire 'Pipeline' as defined in the Code.

Spiralling Up of Asset Regulatory Values, Asset Purchase Prices and Tariffs

AlintaGas submitted that the determination of the Initial Capital Base on the basis of purchase price gives rise to an undesirable precedent in asset valuation, potentially giving rise to a spiralling of asset values and tariffs:[104]

> The National Access Code should not be used to enable Service Providers to bid inflated prices for pipeline systems solely on the basis that they can recover a corresponding inflated price through third party tariffs. Paragraphs 8.1(a), (b) and (d) of the National Access Code are intended to prevent this happening. If the sale price of the DBNGP is used as the initial Capital Base, it would result in the anomalous situation of Service Providers being willing to purchase assets at any cost, confident in the knowledge that they can recoup such costs from third party users over a period of time. If this interpretation of section 8 of the National Access Code were correct, the National Access Code would be "distorting investment decisions", contrary to one of the express objectives in paragraph 8.1(d). It would defeat one of the purposes of competition policy reform, which is to prohibit monopoly asset owners from charging a monopoly rent for use of that asset.
>
> The absurdity in Epic Energy's proposed initial Capital Base can be simply illustrated. Suppose one year after having purchased the DBNGP and prior to the Regulator approving the initial Capital Base, Epic Energy had sold the DBNGP to a related company for, say, $3.5 billion. On Epic Energy's argument, the initial Capital Base for the pipeline would then be $3.5 billion, when nothing about the pipeline had changed. In this scenario, it is difficult to see how the efficient cost of providing DBNGP haulage services could be different before and after Epic Energy sold the pipeline. It is also difficult to characterise the acquirer's recovery (were it permitted) of the extra $1 billion as anything other than monopoly rent.

Epic Energy responded to this submission in relation to the DBNGP as follows.[105]

> AlintaGas concludes that use of a sale price as the initial capital base for reference tariff determination would result in the anomalous outcome of potential purchasers of pipeline assets being prepared to pay any price for them. The resulting higher reference tariffs would then distort investment decisions, and defeat the purpose of competition policy reform that sought to prevent monopoly rent extraction. This conclusion assumes that the process through which the pipeline was sold was not structured in a way that would prevent these economically inefficient outcomes. A simple sale to a related body corporate would not suffice to enable Epic Energy to increase the initial capital base. The regulatory compact is crucial to the regulatory model and hence the use of the purchase price in this instance.
>
> As Epic Energy has described in the Epic First Submission, and in Epic Submission 1, the DBNGP sale process was structured in a particular way. It was structured to deliver both a high sale price for the

[103] North West Shelf Gas Submission 1.

[104] AlintaGas Submission 3.

[105] Epic Energy Submission 5, paragraphs 3.14, 3.15.

> pipeline and lower gas transmission tariffs. It was structured to prevent inefficient outcomes of the type referred to by AlintaGas. To use, as AlintaGas has done, a simple example that ignores the way in which the sale process was structured and executed does not demonstrate the absurdity of Epic Energy's initial capital base. It demonstrates the inappropriateness of using a simple and poorly specified model to address a complex issue.

Epic Energy also made the following comment.[106]

> AlintaGas purports to illustrate an absurdity in our proposal by imagining that transfers of the pipeline assets between private parties would raise the initial Capital Base (p. 11). Our proposal would be absurd if we recommended this approach, but we do not. We do not countenance any upward revision of the initial Capital Base for subsequent transactions between private parties. Once it is set, sales to third parties should not prompt any revision. In support of our proposals, we cited regulatory policy in the United Kingdom. Regulators there were able to set the initial Capital Base by reference to flotation values, and have not been deluded into subsequent regulatory revaluations as share prices subsequently increased, or as some companies were acquired by others.

Epic Energy also addressed AlintaGas's concern over implications for sales of other pipeline assets:[107]

> If our proposal is adopted, the Government in the future will retain the ability to continue along the same path that it presumably followed in the past—making appropriate trade-offs between the combinations of bids and tariff schedules that competing businesses may offer.

**Regulator's Response to Submissions**

In summary, the submissions on the proposed Access Arrangement addressed the issue of whether the Initial Capital Base should be valued at the purchase price of the DBNGP by Epic Energy. Submissions addressed issues of whether the Initial Capital Base should be set at a value outside of, and above, the range of DAC and DORC, and in particular whether the Initial Capital Base should be valued at Epic Energy's cost of purchase of the DBNGP.

These issues relate to specific factors that sections 8.10 and 8.11 of the Code require to be considered in relation to establishing the Initial Capital Base for a pipeline that was in existence at the commencement of the Code. These factors include the values that may be derived by different valuation methodologies, including DAC and DORC values, and the advantages and disadvantages of the different methodologies (paragraphs 8.10(a), 8.10(b), 8.10(c) and 8.10(d) of the Code), and the price paid for the assets recently purchased by the Service Provider (paragraph 8.10(j) of the Code).

The Regulator's deliberations in regard to each of the specific factors required under sections 8.10 and 8.11 of the Code to be considered in the valuation of the Initial Capital Base are set out in section 5.3.4 of this Draft Decision.

The Regulator gave attention to the advantages and disadvantages of different valuation methodologies, including DAC and DORC estimates, and came to the conclusion that the Initial Capital Base should not be valued outside the range of DAC and DORC. Further, and as specifically required by paragraph 8.10(j) of the Code, the Regulator gave attention to the sale price of the DBNGP to Epic Energy and the circumstances of the sale. In this regard, the Regulator has addressed a number of factors that affect the purchase price that would not be appropriate in considering the establishment of a value for the Initial Capital Base of the DBNGP. These were addressed in several submissions and are further considered on page 144 below.

[106] Epic Energy Submission 5 Appendix 1 section 2.3.
[107] Epic Energy Submission 5 Appendix 1 section 2.2.

The Regulator notes that in determining an offer for purchase of the DBNGP assets, Epic Energy may have made assumptions about numerous factors affecting the expected value of the pipeline (as outlined in public submissions). These assumptions may have included forecasts of gas throughput and a level of risk to be borne in respect of assumptions as to future throughput. The Regulator did not make an assessment of a reasonable purchase value of the pipeline for different forecasts of gas throughput. However, the Regulator did give attention to whether the purchase price may have been a reasonable valuation of the assets given an assumed gas throughput and other relevant considerations (section 5.3.4.5 of this Draft Decision, below). Furthermore, the Regulator considered the circumstances of the sale and the expectations that may have been created in regard to the valuation of the DBNGP under the Code relative to DAC and DORC values (section 5.3.4.11 of this Draft Decision).

#### 5.3.3.4 The Magnitude of the Initial Capital Base

**Submissions**

Several submissions indicated opposition to the magnitude of the proposed Initial Capital Base, regardless of the relativity to DAC and DORC values or determination on the basis of the purchase price. Reasons put forward in support of this opposition are summarised as follows:

- The Initial Capital Base proposed by Epic Energy is inconsistent with the objectives for a Reference Tariff Policy and Reference Tariff set out in paragraphs 8.1(a) and 8.1(b) of the Code of 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, and replicating the outcome of a competitive market. The "inflated" Initial Capital Base proposed by Epic Energy is inconsistent with efficient costs, and the Initial Capital Base valuation should, for a given asset, be similar for any Service Provider, whether that Service Provider is government owned or a private firm. The "efficient cost", by definition, does not include an inflated Capital Base, or a Capital Base that is set by reference to a price that includes other strategic factors.[108]
- Allowing Service Providers to establish regulatory asset values equal to purchase values of assets would result in Service Providers being willing to purchase assets as any cost, confident in the knowledge that they can recoup such costs from third party users over a period of time. This would be contrary to the objective for a Reference Tariff Policy and Reference Tariff set out in paragraph 8.1(d) of the Code of not distorting investment decisions in pipeline transportation systems, and would defeat one of the purposes of competition policy reform, which is to prohibit monopoly asset owners from charging a monopoly rent for use of that asset.[109]
- While the Initial Capital Base proposed by Epic Energy is not being used directly to determine the Reference Tariff in the usual way of setting tariffs to achieve a predetermined return on the Capital Base, the high Initial Capital Base creates the possibility that tariffs could in future be driven to higher levels by the value of the Capital Base.[110]

[108] AlintaGas Submission 3.

[109] AlintaGas Submission 3.

[110] Chamber of Minerals and Energy. Note that Epic Energy has established a price path for tariffs that is independent of the cost-of-service calculations and the Total Revenue requirement. Hence under the tariff determination methodology utilised by Epic Energy, the Reference Tariff is, for all practical purposes,

- The high Initial Capital Base could be contrary to the international competitiveness of energy consumers competing in international markets, which comprise significant users of gas transported through the DBNGP. The Regulator is required by paragraph 8.10(e) of the Code to consider this matter.[111]
- The Initial Capital Base proposed by Epic Energy is inconsistent with the cost structure of a new pipeline that may compete with the DBNGP, as the Regulator is required to consider under paragraph 8.10(i) of the Code. There is a real prospect that the DBNGP could be by-passed by a newer, lower cost pipeline in the foreseeable future and in any event, from Mondarra south, the pipeline is already paralleled by the Parmelia pipeline and care needs to be paid by O*ff*GAR to the relative transportation tariffs applying over this portion of the DBNGP system.[112]
- The Initial Capital Base proposed by Epic Energy is contrary to the reasonable expectations of Users under the regulatory regime that applied to the pipeline prior to the commencement of the Code, as the Regulator is required to consider under paragraph 8.10(g) of the Code.[113] This includes being contrary to indications from the Minister for Energy's second reading speech in connection with the Gas Pipelines Access (Western Australia) Act in which he stated that "Firm full-haul tariff at 100 percent load factor will fall from $1.19 per gigajoule to $1.00 per gigajoule by the year 2000".[114]
- The Initial Capital Base proposed by Epic Energy is contrary to the efficient utilisation of gas resources, as the Regulator is required to consider under paragraph 8.10(h) of the Code, as it results in a tariff higher than that which would reflect efficient costs.[115] The high costs of gas transmission in the DBNGP will reduce demand for gas and reduce incentives for any new pipeline operators to enter the market.[116]

Contrary to most submissions that indicated a view that the Initial Capital Base proposed by Epic Energy is excessive, the submission from CMS Gas Transmission indicated some implicit support for Epic Energy's valuation of the Initial Capital Base. This view seems to arise from a consideration that the rate of return on the Capital Base that would likely be allowed by the Regulator would be too low to enable generation of a sufficient revenue flow for the Service Provider, hence the Service Provider is motivated to secure a higher valuation of the Initial Capital Base so as to generate sufficient revenue:

> CMS is of the view that it might be worthwhile to consider Epic's apparently optimistic [Initial Capital Base] proposal in context.
>
> In establishing the purchase price which it was prepared to bid for the DBNGP, Epic was faced with a known tariff expectation (publicised by the State Minister for Energy and Resource Development) which, in accordance with standard valuation methodology, would have been combined with assumptions about required rates of return, risk acceptance and load and market growth potential. If Epic chose to be more aggressive than its rivals in these assumptions, then that may be considered a reasonable commercial prerogative. However, in the context of regulatory compliance, Epic's requirement to claim such a high

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independent of the Initial Capital Base for the first Access Arrangement Period. This is further discussed in section 5.9 of this Draft Decision.

[111] WMC, Worsley Alumina, Mark Neville MLC, Energy Markets Reform Forum.

[112] WMC.

[113] WMC, Worsley Alumina.

[114] Worsley Alumina. It is understood by the Regulator that Worsley refer to a perception that gas transportation costs will be higher under the proposed Access Arrangement, for the same total transportation service, that under the current tariff regime established under the Gas Transmission Regulations.

[115] Worsley Alumina, South West Development Commission, Cockburn Cement.

[116] South West Development Commission.

> capital base is a direct reflection upon the regulatory adoption of unrealistic rates of return (as a consequence of basing outcomes on erroneous assumptions and slavishly following inappropriate precedents) as well as the 'cherry picking' of parameters by Regulators to achieve their own preconceived outcomes.
>
> In a regulatory environment which permits only such unattractively low rates of return, Epic have little choice but to claim the [Initial Capital Base] which they have in order to attempt to sustain the tariff outcomes which have been preordained for them (notably without the benefit of any quantitative economic rationale) and upon which, presumably, their purchase of the DBNGP was justified. In accepting this valuation of the DBNGP, the Western Australian Government implicitly accepted this as the basis upon which future tariffs would be determined. Clearly, the current expectation of regulatory outcomes does little to promote economic efficiency, either directly by mandatory imposition or by the stimulation of competition and development.

In response to the above views expressed in submissions Epic Energy submitted that the view expressed in several submissions that the proposed Initial Capital Base results in a Reference Tariff that is higher than might otherwise have been the case is incorrect and reflects a misunderstanding about the role of the Initial Capital Base in determining the Reference Tariff proposed for the DBNGP Access Arrangement.[117] In response to the views expressed in submissions, Epic Energy referred to the explanation of the determination of the Reference Tariff in section 2.1 of the Access Arrangement Information indicating that the basic "full-haul" Reference Tariff was determined through the sale process and the specification in Schedule 39 to the Asset Sale Agreement of tariffs that Epic Energy intended to have apply as of 1 January 2000, and a particular price path of tariffs thereafter. Notwithstanding this, Epic Energy stated that:

> An explicit capital base, established down to the level of relevant asset classes and, in some cases, individual assets, is necessary for determining a complete set of tariffs for the current access arrangement period, and for providing a basis for subsequent tariff re-determination. The DBNGP purchase price of $2.407 billion, adjusted for new capital expenditure and depreciation from the date of purchase to commencement of the proposed Access Arrangement, and the detailed set of asset of values established by valuers Edward Rushton Australia Pty Limited consistent with the adjusted purchase price, provides a logical and clearly verifiable initial capital base. This aspect is dealt with more fully in the 15 December submission and the associated Brattle Group Report.[118]

Epic Energy has addressed the consistency of the proposed Initial Capital Base with the factors of paragraphs 8.10(e) to 8.10(i) of the Code, as follows.[119]

> Paragraph 8.10(e) refers to "international best practice of Pipelines in comparable situations". As shown in the two reports from Epic Energy's regulatory experts, The Brattle Group, the same approach has been taken in the United Kingdom with respect to the privatised natural gas transmission infrastructure and with respect to privatised electricity transmission and distribution infrastructure. In addition, the approach is consistent with developments in the USA.
>
> Paragraph 8.10(e) also refers to impact on international competitiveness. The Government had sought a lowering of tariffs and determined what was appropriate for Western Australia. In selling the DBNGP to Epic Energy, the Government determined that the tariff and the tariff path proposed by Epic Energy met its requirements. The Government was well placed to do so. Government agencies directly involved in the Pipeline sale process – in particular, the Treasury and the Department of Resources Development – were well placed to assess a level for future gas transportation tariffs consistent with the continuing international competitiveness of Western Australian industry. Furthermore, as Epic Energy has shown, the proposed reference tariff for the DBNGP compares favourably with tariffs for Kern River Pipeline, a US pipeline similar to the DBNGP, which supplies gas into California.[120]

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[117] Epic Energy Submission 3, paragraph 4.3 et seq.

[118] Epic Energy Submission 3, paragraph 4.3.8.

[119] Epic Energy Additional Paper 5, section 3.21.

[120] See Epic Energy Submission 3 section 6.

Paragraph 8.10(f) refers to "the basis on which Tariffs have been…set in the past". This has been dealt with in some detail in Epic Energy Submission 7 at section 3.1. In short, Epic Energy notes that the last rate set by the State was the 1999 tariff, being a full haul tariff of $1.09/GJ. The $1.00/GJ tariff imposed for 2000 was artificially imposed, and against Epic Energy's agreement or expectations. Neither of these tariffs was fixed in any considered way, or according to any principles. In fact, the last tariff fixed in accordance with any principles was the 1998 tariff which produced a T1 full haul tariff of $1.18/GJ. In any event, those tariffs were prescribed in a different environment and do not provide any useful yardstick. Nevertheless the proposed Reference Tariff compares favourably with tariffs set in the past.

Paragraph 8.10(g) refers to the reasonable expectations of persons under the prior regulatory regime. The documents filed by Epic Energy with the Regulator have gone to some length in dealing with what these expectations were. In the case of the Government, it was for tariffs as contained in Schedule 39 of the DBNGP Asset Sale Agreement. In the case of existing and prospective Shippers, it was for a tariff of around $1.00/GJ to Perth. In the case of Epic Energy, the Service Provider, it was for the tariffs contained in Schedule 39. In the case of Shippers continuing under the GTR regime, it was for a tariff of around $1.18/GJ for full haul T1 Service. Epic Energy contends that the reasonable expectation was for the tariffs as set out in Schedule 39, namely $1.00/GJ to Perth, $1.08/GJ to south of Perth, and the tariffs escalated by 67% of CPI.

Paragraph 8.10(h) deals with the economically efficient utilisation of gas resources. The people with the best knowledge of this, the Government and its officers on the Gas Pipeline Sale Steering Committee, put Epic Energy's proposed tariff and tariff path as contained in Schedule 39, under rigorous scrutiny. They determined it achieved what the Government was seeking in respect of tariffs. Hence it can be interpolated that this objective is satisfied. In addition, the proposed Access Arrangement involves prices that decline steadily in real terms per unit volume, consistent with efficient markets and avoiding the "rate shock" that can arise when straight-line or other depreciation schedules are used.

Paragraph 8.10(i) points to the risk of by-pass. Epic Energy's price was based on the assumption of volume growth. It took knowingly the volume risk, that risk being central to the regulatory model adopted in the proposed Access Arrangement. Epic Energy was involved in a competitive bid process to acquire the DBNGP in an environment when demand for capacity on the DBNGP was expected to nearly double over a short period of time. One of the central elements of the regulatory compact was the commitment by Epic Energy to expend in the order of $870 million expanding the DBNGP to meet demand. If the capital base (the purchase price) and the associated tariff were not reasonable, then it would be expected that bypass would occur. In fact the State, using part of the sale proceeds received from Epic Energy, ran a process seeking expressions of interest for additional capacity to Perth, and widened the existing pipeline corridor to accommodate potential new pipelines. To date there is no indication of a second pipeline being built. However, while Epic Energy acknowledges that it may be at risk in this area, it is important to remember that the proposed capital base represents the quantum for the total expected volumes not just the current volumes. The regulatory model adopted by Epic Energy ensures that there is not over recovery and, in fact, if the volumes do not materialise, Epic Energy loses that part of the capital base not recovered as an imprudent investment.

### Regulator's Response to Submissions

In summary, the submissions from parties other than Epic Energy on the magnitude of the proposed Initial Capital Base generally expressed concern as to the potential effect of the valuation in increasing tariffs, either at the current time or in the future, and the inconsistency of the proposed value of the Initial Capital Base with the factors set out in paragraphs 8.10(e) to 8.10(i) of the Code. These provisions of the Code require consideration in establishing the Initial Capital Base of, respectively, international best practice of pipelines and international competitiveness of energy consuming industries; reasonable expectations of persons under the regulatory regime that applied to the DBNGP prior to the commencement of the Code; impact on the efficient utilisation of gas resources; and comparability with cost structure of new pipelines that may compete with the DBNGP.

The Regulator's deliberations on these issues are set out in detail in section 5.3.4 of the Draft Decision in relation to each of the specific factors required by section 8.10 of the Code to be considered in establishing the Initial Capital Base.

In relation to the potential impacts of the proposed Initial Capital Base on the international competitiveness of energy consuming industries, the efficient utilisation of gas resources; and comparability with cost structure of new pipelines that may compete with the DBNGP, the Regulator gave particular attention to the efficiency arguments for an upper bound on an Initial Capital Base to be a DORC valuation, as contemplated in section 8.11 of the Code (section 5.3.4.5 of this Draft Decision). The Regulator also gave attention to international regulatory practice (section 5.3.4.6 of this Draft Decision).

In considering the reasonable expectations of persons under the regulatory regime that applied to the DBNGP prior to the commencement of the Code, the Regulator noted that transmission tariffs for the DBNGP have previously been determined on the basis of written-down "book values" of assets. If past regulation were 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 of assets as at 31 December 1994. This matter is considered in more detail in section 5.3.4.8 of this Draft Decision.

#### 5.3.3.5 Alternative Valuation Methodologies for the Initial Capital Base

**Submissions**

Two submissions advocated use of alternative methodologies for valuing the Initial Capital Base and altering the value of the Capital Base over time.

- Worsley Alumina

  An alternative valuation method that recognises uncertainty in forecasting is to allow a pipeline residual value at the end of the Access Arrangement period. Worsley believes that the best estimate of residual value for this purpose is the projected DORC at that time. The Reference Tariff is then calculated from a financial analysis over the Access Arrangement Period rather than the full life of the asset. This allows the "asset value" of the pipeline consumed in delivering the Services during the Access Arrangement Period to be recovered during that period. This will prevent the cost of over-investment in the pipeline being borne by the users in that period but allow the full economic value to be recovered over the pipeline life. This approach should not result in under-investment in the pipeline as s8.15 *et seq*. allows for investment in new facilities during an Access Arrangement Period. This approach is consistent with the "price path" approach that Epic has chosen. Implicit in this arrangement, however, is that the Initial Capital Base at the beginning of the Access Arrangement period is the DORC for a pipeline sized according to the projected gas volumes for that period. Any excess capacity, and any excess price paid for this, is speculative investment that should not be recovered in the tariff for that period.

- Treasury/Office of Energy

  The Regulator may need to assess the suitability (and availability) of alternative mechanisms under the Code to achieve similar outcomes to the ones sought by Epic Energy via the application of the deferred recovery account balance. A key consideration in this regard could be the risk-transferring properties of the relevant alternatives. One such mechanism may be able to be developed by deeming the pipeline to comprise "new facilities" in the context of its recent purchase by Epic Energy and thereby accept that part of Epic Energy's investment is New Facilities Investment that does not satisfy the requirements of section 8.16 of the Code. This will present an opportunity to place a proportion of the proposed Initial Capital Base in the "speculative investment fund" and subsequently add back corresponding portions of it when increases in throughput warrant investment in new facilities. However, if such a mechanism is applied the Regulator would be requested to consider increasing the "speculative investment fund" with a rate of return different than the one applied to the "contributing" initial capital base (commensurate with the risk transferring properties of such a mechanism), which would share volume forecast risks between the Service Provider and the users of the pipeline. Further the Regulator may wish to consider if it would be more appropriate to increase the "speculative investment fund" with the CPI or appropriate risk free rate and not the firm's rate of return.

Epic Energy responded to the submission from Treasury/Office of Energy as follows.[121]

> Treasury and Office of Energy discuss an alternative approach involving a "speculative investment fund," in which a proportion of the initial capital base would be placed, and "subsequently add[ed] back… when increases in throughput warrant investment in new facilities" (p. 9). There are some significant differences between our proposal and the "speculative investment fund," but an elaboration of the comparison may aid in understanding our proposal and can also serve to illustrate its advantages.
>
> There are three key differences between our proposal and the speculative investment fund. First, as we understand it, the principle behind the "speculative investment fund" has only been defined generally to involve some unspecified "portion" of a company's initial capital base, perhaps corresponding directly to some physical assets. The deferred recovery account under our proposal has been defined quite clearly by reference to Epic's purchase price and the tariff trajectory in Schedule 39: it is simply the deferred return on Epic's invested capital that inevitably arises from the immediate implementation of the Schedule 39 tariffs. Second, recovery of the "speculative investment fund" would presumably commence when new investments are required. Under our proposal, the deferred recovery account is depleted naturally under the Schedule 39 tariffs when *and if* utilisation of the pipeline increases to levels that would justify Epic's initial purchase price.
>
> Our proposal is conservative in some respects relative to the "speculative investment fund". Treasury and Office of Energy recognise that perhaps a *higher* cost of capital is required for the assets in the speculative investment fund, because their recovery is more uncertain. Under our proposal, Epic effectively bears the risk of recovering its initial purchase price, as it might under a speculative investment fund, but *without* any upward adjustment to the cost of capital.

**Regulator's Response to Submissions**

The submissions from Worsley Alumina and Treasury/Office of Energy suggested use of alternative valuation methods of the Capital Base, or alternative methods of taking the Value of the Capital Base into account in determining Reference tariffs. Worsley Alumina suggest re-valuation of the Capital Base at the commencement of each Access Arrangement Period by a DORC value at those times. Treasury/Office of Energy suggest treating part of the value of the Capital Base as speculative investment in line with provisions of section 8.19 of the Code, and not taking this part of the value into account in determination of tariffs until warranted by an increase in throughput.

The valuation methodologies and treatments of the Capital Base suggested by Worsley Alumina and the Treasury/Office of Energy cannot currently be accommodated within the relevant provisions of the Code. The Code provides for establishment of an Initial Capital Base, and subsequent adjustment of the Capital Base by a mechanistic procedure involving the addition of capital expenditure and subtraction of depreciation and redundant capital (Code section 8.9). No provision is made for revaluation of the Capital Base other than by this procedure. Further, although the Code does provide for New Facilities Investment to be deemed speculative investment, no provision is made for a portion of the Capital Base to be treated as speculative investment. The Regulator therefore considers that regardless of the merit of the proposals by Treasury/Office of Energy and Worsley for treatment of the Capital Base, these proposals are precluded from consideration by provisions of the Code. However, the Regulator also notes that Epic Energy's proposal deferred recovery of capital costs has the same essentially the same effect as a speculative investment fund, although by a nominally different mechanism.

[121] Epic Energy Submission 5 Appendix 1 section 1.5.

#### 5.3.3.6 Initial Capital Base as a Fixed Principle

**Submissions**

Epic Energy has proposed that the Initial Capital Base be a fixed principle within the meaning of section 8.48 of the Code and therefore not subject to change upon subsequent review of the Access Arrangement without agreement of the Service Provider.[122]

Treasury/Office of Energy submitted that the Regulator may need to consider whether such a fixed principle should be accepted as part of the Access Arrangement:

> The Regulator is encouraged to consider, under section 8.48 of the Code, the implications of the initial capital base being deemed to be a "fixed principle". It would appear that calculating and revising the capital base in accordance with section 7.3 of the proposed Access Arrangement would be likely to impart an upward bias on the value of the capital base over time. The Regulator may need to consider whether flexibility should be retained to adjust any estimate of the Initial Capital Base to reflect economic efficiency at the time that future access arrangements are entered into.

Worsley Alumina objected to the proposal for the Initial Capital Base to be a Fixed Principle on the basis that the Initial Capital Base is in the nature of a capital cost which is excluded from being a fixed principle by the definition in the code of Market Variable Elements which cannot be fixed principles and which include costs in the nature of capital costs.

**Regulator's Response to Submissions**

A fixed principle is defined in section 8.47 of the Code as:

> … an element of the Reference Tariff Policy that cannot be changed without the agreement of the Service Provider.

Section 8.48 of the Code indicates that a fixed Principle may include any Structural Element, which is defined in section 10 of the Code as:

> … any principle or methodology that is used in the calculation of a Reference Tariff where that principle or methodology is not a Market Variable Element and has been structured for Reference Tariff making purposes over a longer period than a single Access Arrangement Period … .

A Market Variable Element is defined in Section 10 of the Code as:

> … a factor that has a value assumed in the calculation of a Reference Tariff, where the value of that factor will vary with changing market conditions during the Access Arrangement Period or in future Access Arrangement Periods … .

The Initial Capital Base would not fall within the scope of the definition of a Market Variable Element as it is not subject to change with changing market conditions.

It is conceivable that the Initial Capital Base could fall within the scope of the definition of a Structural Element, although the Code does not include the Capital Base within examples given of factors that may comprise Structural Elements, which include the Depreciation Schedule, and the financial structure that is assumed for the purposes of determining the Rate of Return.

The Regulator is of the view that the Code does not contemplate any revision of the value of the Initial Capital Base for a pipeline, and that the Initial Capital Base would not be changed

[122] Note that in section 7.15 of the Access Arrangement, Epic Energy indicates that "the Initial Capital Base is a fixed principle for the purposes of section 7.12 of the Code." The Regulator assumes that the Reference to section 7.12 of the Code is an error in drafting of the Access Arrangement and should in fact be a reference to either section 7.12 of the Access Arrangement (relating to incentive mechanisms) or section 8.47 of the Code (relating to fixed principles).

as part of any review of the Access Arrangement, and hence whether the Initial Capital Base is or is not a fixed principle is inconsequential for any review. Rather, the Code (section 8.9) provides for the determination of the Capital Base at the commencement of each Access Arrangement Period after the first, by a mechanistic procedure of adding capital expenditure and subtracting depreciation and redundant capital. As such, the Regulator requires that the proposed Access Arrangement should be amended to remove provision for the Initial Capital Base to be a fixed principle.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 51<br><br>Clause 7.15 of the proposed Access Arrangement should be deleted to remove provision for the Initial Capital Base to comprise a fixed principle within the meaning of section 8.48 of the Code. |

### 5.3.4 Additional Considerations of the Regulator

#### 5.3.4.1 Factors that the Code Requires to be Considered

The Code requires that, in establishing a value for the Initial Capital Base, consideration be given to the factors set out in section 8.10 of the Code. Discussion of these factors in relation to valuation of the Initial Capital Base for the DBNGP is presented below.

#### 5.3.4.2 Depreciated Actual Cost

Paragraph 8.10(a) of the Code 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.

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, for the purposes of this Draft Decision, referred to as a Depreciated Actual Cost (DAC).

Epic Energy provided an estimate of the DAC value of the DBNGP of $2,466.1 million, determined on the basis of the acquisition cost of the DBNGP to Epic Energy, less the amount of depreciation thought by Epic Energy to have been collected by SECWA and AlintaGas from third parties (including the trading division of AlintaGas) and less the amount of depreciation recovered by Epic Energy from third parties since purchase of the DBNGP.[123]

Epic Energy's position on the interpretation of "actual capital cost" as the acquisition cost is as follows.[124]

> Paragraph 8.10(a) of the Code requires that "accumulated depreciation for [the assets forming a Covered Pipeline] charged to users (or thought to have been charged to Users) prior to the commencement of the Code" be subtracted from "the actual capital cost of the Covered Pipeline".

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

[124] Epic Energy Additional Paper 5, Attachment 4: Initial Capital Base Valuation Methodologies, pp 3, 4.

The term "actual capital cost" is not defined anywhere in the Code. Nor does there appear to be any case law in Australia that provides any guidance on the meaning of the term in this specific context, or in any other directly analogous context.

The immediate problem with the absence of a definition is that the term "actual capital cost" is ambiguous in Paragraph 8.10(a) when read in isolation. The term is of a technical nature and could be said to refer to either the *historical construction/expansion cost* incurred by the owner or owners of the pipeline, or the *acquisition cost* incurred by the current Service Provider in acquiring the pipeline. Both categories of cost are equally "actual" and equally of a "capital" nature.

The use of the term "actual capital cost" in Paragraph 8.10(a) of the Code should be contrasted with its use in Sections 8.12.

Section 8.12 of the Code provides: "When a Reference Tariff is first proposed for a Reference Service provided by a Covered Pipeline that has come into existence after the commencement of the Code, the initial Capital Base for the Covered Pipeline is, subject to section 8.13, the actual capital cost of those assets at the time they first enter service."

Significantly, the qualification "*at the time* [the pipeline assets] *first enter service*" does not appear in paragraph 8.10 (a).

One of the basic rules of statutory interpretation is that where Parliament could have used the same word or words, but chooses to use a different word or words, its intention is to convey a different meaning.

According to this general rule, "actual capital cost" when used in paragraph 8.10(a) means something different from, or not necessarily limited to, the "*actual capital cost* [of the pipeline assets] *at the time they first enter service*".

Importantly, the latter term is almost certainly intended to be a reference to the "historical cost" or "original cost" associated with the construction/expansion of the pipeline. This clearly suggests that the term "actual capital cost" in paragraph 8.10(a) is to have a meaning different from historical or original cost in this sense.

Paragraph 8.10(a) is relevant to setting the initial Capital Base for existing pipelines, including pipelines that have been in existence for a long time. If "actual capital cost" were meant to be restricted to the actual capital cost at the time these pipelines first entered service then this would lead to the result (even assuming a single owner) of not allowing subsequently incurred capital expenditure in expanding or enhancing the pipeline over time to be included in the calculation of the actual capital cost, which would be the case when Section 8.12 is taken with Section 8.13 of the Code. This cannot have been the intention behind the wording in paragraph 8.10(a) of the Code when read in context.

It is also useful to look at what the treatment is in practice. Standard accounting practice, practice adopted by Epic Energy, requires that acquired assets be recorded and reported at their costs of acquisition. In accordance with this practice, the cost of acquiring an asset is the purchase consideration plus any costs incidental to the acquisition. Furthermore, subsequent additions to the asset are to be recorded and reported at cost.

For Epic Energy, as the Service Provider, the actual capital cost of the DBNGP then comprises two components:

– the cost Epic Energy incurred in acquiring the Pipeline - its purchase consideration, $2,407.0 million, plus net costs incidental to the purchase, which amounted to $42.5 million; and

– the capital costs of enhancement and expansion of the Pipeline after acquisition, which amounted to $121.6 million for the period from 25 March 1998 to 31 December 1999.

By this interpretation of "actual capital cost", Epic Energy considered the actual capital cost of the DBNGP to be $2,571.1 million, comprising the sum of:

- the cost Epic Energy incurred in acquiring the pipeline – its purchase consideration, plus net costs incidental to the purchase which amounted to $42.5 million; and

- the capital costs of enhancement and expansion of the pipeline after acquisition, which amounted to $121.6 million for the period from 25 March 1998 to 31 December 1999.[125]

In subtracting accumulated depreciation from the actual capital cost, paragraph 8.10(a) of the Code refers to depreciation as "the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code."[126] For the purposes of estimating the accumulated depreciation, Epic Energy considered a "User" to be a third party provided with a gas transmission service, and therefore relevant depreciation to comprise:

- "the depreciation charged by SECWA to Alcoa of Australia for gas from third party suppliers transported in accordance with the modifications to the Natural Gas Sales Agreement made in 1991 and 1994 (these estimates being made on the basis of very limited information and an incomplete understanding of the basis for the structure of charges in the Natural Gas Sales Agreement);
- depreciation charges by AlintaGas under the pricing provisions of the GTRs, including depreciation charged to AlintaGas's "other business" (although it could be argued that that does not come within the meaning of paragraph 8.10(a)); and
- depreciation charged by Epic Energy through the tariffs of the transitional access regime, the repealed access regime, and under the Alcoa contract."[127]

Epic Energy noted in its discussion of the estimation of accumulated depreciation that:

> Other than in respect of Alcoa as described above, no allowance has been made for SECWA's depreciation of the pipeline. SECWA itself was not a User in accordance with the definition of that term in the Code.[128]

Epic Energy's estimation of accumulated depreciation within the interpretation given by Epic Energy to paragraph 8.10(a) of the Code was $105.0 million. Epic Energy's valuation of the pipeline assets under paragraph 8.10(a) of the Code was therefore $2,466.1 million, as at 1 January 2000.

Epic Energy also provided in the Access Arrangement Information an estimate of a valuation under paragraph 8.10(a) of the Code based on an interpretation of "actual capital cost" as the historical cost of pipeline assets. Taking into account the same value of accumulated depreciation as indicated above ($105.0 million), Epic Energy indicates the valuation based on historical cost to be $1,331.5 million, with this value qualified by a statement that it is a rough estimate as Epic Energy did not obtain records from AlintaGas (i.e. the Gas Corporation) which would enable estimation with any degree of accuracy.[129]

In summary, Epic Energy's estimation of a DAC value was based on two matters of interpretation of paragraph 8.10(a) of the Code:

i. 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

[125] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 4.

[126] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 4.

[127] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 5.

[128] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, pp 5, 6.

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

investment comprised the construction cost of assets or the cost of purchase of existing assets; and

ii. 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.

The Regulator favours an alternative interpretation of paragraph 8.10(a) of the Code in regard to both the meaning of "actual capital cost" and the meaning of "accumulated depreciation charged to Users."

In regard to the meaning of "actual capital cost" in paragraph 8.10(a) of the Code, the Regulator is of the view that while this term 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, would be consistent with a meaning of the cost of construction of the relevant assets. Further, an alternative interpretation may be inconsistent with the objectives for a Reference Tariff set out in section 8.1 of the Code, as set out below.

- As is reflected in the overview to section 8 and in section 8.1 of the Code, an objective in designing the Reference Tariff Policy is not so much to provide the Service Provider with a return on its investment generally as it is to provide a return on the assets comprising the Covered Pipeline.
- Under section 8.11, the value derived under paragraph 8.10(a) is expected to comprise the lower bound of potential values for the Initial Capital Base. If it were possible to interpret paragraph 8.10(a) as referring to the price paid by the Service Provider to acquire the relevant Covered Pipeline (where the Service Provider is not the first owner), then the objectives set out in paragraphs 8.1(a) and (d) of the Code would not be achieved. This is because potentially more than the efficient costs of providing the Reference Service may be recovered (paragraph 8.1(d)) and investment decisions in pipeline transportation systems may be distorted (paragraph 8.1(d)) as Service Providers would have an incentive to pay substantially more than the original construction cost to acquire a Covered Pipeline.

In regard to the meaning of "accumulated depreciation charged to Users (or thought to have been charged to Users) prior to the commencement of the Code", Epic Energy has referred to the definition of User in section 10.8 of the Code, being "a person who has a current contract for a Service or an entitlement to a Service as a result of an arbitration". Thus, Epic Energy has interpreted paragraph 8.10(a) as requiring recognition only of depreciation charged to a person that has a contract for a Service, which may not include any depreciation of assets arising from gas transmission by an owner of a pipeline on its own behalf and for which an explicit transmission contract did not exist.

The Regulator considers that the interpretation given to paragraph 8.10(a) by Epic Energy is inappropriate. As indicated above, "User" is defined in section 10.8 of the Code as "a person who has a current contract for a Service or an entitlement to a Service as a result of an arbitration". "Service is defined in the Code as:

> a service provided by means of a Covered Pipeline (or when used in section 1 [of the Code] a service provided by means of a Pipeline] including (without limitation):
>
> (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and back haul);
>
> (b) the right to interconnect with the Covered Pipeline; and
>
> (c) services ancillary to the provision of such services,

but does not include the production, sale or purchasing of natural gas.

Under the definition in section 10.8 of the Code, Service (and hence User) only has meaning in respect of a Covered Pipeline, and therefore only has meaning since the commencement of the Code. This is obviously nonsensical for paragraph 8.10(a) of the Code for which accumulated depreciation must be considered for the period prior to the commencement of the Code. Hence operation of paragraph 8.10(a) requires that the term "User" is ascribed a broader meaning than the definition in section 10.8 of the Code.

The Regulator is of the view that it is reasonable to ascribe a meaning to the term "User" in paragraph 8.10(a) of the Code as any party on whose behalf gas is transported, which may include the owner of the pipeline if the owner transports gas on its own behalf. This interpretation is consistent with the situation that would exist subsequent to the commencement of the Code for a pipeline owner transporting gas on its own behalf, as such a pipeline owner would have to operate within the provisions of the Code relating to ring fencing and associate contracts, and hence the pipeline owner would constitute a User under the definition of User in section 10.8 of the Code. Within this interpretation of the paragraph 8.10(a) Code, SECWA would be considered to have been a User of the DBNGP for the purposes of estimating accumulated depreciation prior to commencement of the Code.

The estimation of accumulated depreciation charged to Users, or thought to have been charged to Users, is problematic inasmuch as historic tariffs for gas transportation may not have been determined by a "building block" approach with a specific allowance for depreciation.[130] Furthermore, where a pipeline owner transported gas on its own behalf, there may not have been any mechanism within the pipeline owner's business for charging for gas transportation or allocating business revenue to gas transportation activities. While financial accounts may provide a book value for gas transmission assets that takes account of past accounting depreciation, past accounting depreciation does not necessarily bear any relation to a return of capital either through specific depreciation components in gas transmission tariffs or implicitly in gas transmission revenues.

The book value of assets may, however, be considered to constitute an upper bound estimate of a DAC value, if it were to be assumed that accounting depreciation would be no greater than the actual return of capital.

A pro forma net assets statement for the DBNGP assets at 30 June 1997, included in the Information Memorandum in relation to the sale of the DBNGP, indicated a book value of non-current pipeline assets of $929.8 million and a further value of current assets included in the DBNGP sale of $6.3 million, giving a total book value of pipeline assets of $936.1 million, itemised as follows.[131]

[130] A "building block" approach to tariff determination refers generally to a methodology whereby the total cost of providing pipeline services is determined by estimating and then summing individual cost components such as return on capital, depreciation and non-capital costs.

[131] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 133.

**DBNGP Assets: Information Memorandum Assets Statement**

| Asset | Value at 30 June 1997 ($million) |
|---|---|
| **Current assets** | |
| Inventory | 2.1 |
| Linepack | 4.2 |
| **Total current assets** | **6.3** |
| **Non-current assets** | |
| Pipeline and facilities | 890.5 |
| Easements, access roads etc. | 19.6 |
| Freehold land | 0.9 |
| Depots and staff housing | 6.5 |
| Motor vehicles, furniture and fittings | 3.2 |
| Computer equipment | 1.2 |
| Workshop and maintenance equipment | 4.1 |
| Strategic spares | 3.8 |
| **Total non-current pipeline assets** | **929.8** |
| **Total Pipeline Assets** | **936.1** |

A book value for the pipeline assets as at 31 December 1999 can be estimated by addition of capital expenditure and subtraction of depreciation for the period 1 July 1997 to 31 December 1999.

Epic Energy has indicated capital expenditure for the period to be as follows.[132]

**DBNGP Capital Expenditure July 1997 to December 1999**

| Expenditure | Actual Cost ($million) |
|---|---|
| AlintaGas 1 July 1997 to 24 March 1998 | 28.2 |
| Epic Energy 25 March 1998 to 31 December 1999 | 121.6 |
| **Total** | **149.8** |

The Regulator was not provided with information on the accounting depreciation of assets for the period 1 July 1997 to 31 December 1999. Epic Energy provided estimates of depreciation

[132] Spreadsheet accompanying letter from Epic Energy to Office of Gas Access Regulation: Basis of Estimate of Depreciated Historical Cost, 9 August 2000, Epic Energy reference DW/jp.

charged to third parties over the period (as a component of tariffs under the Gas Transmission Regulations), as follows.[133]

**DBNGP Epic Energy Estimates of Depreciation Charged to Users July 1997 to December 1999**

| Expenditure | Depreciation ($million) |
|---|---|
| AlintaGas 1 July 1997 to 24 March 1998 | 6.56 |
| Epic Energy 25 March 1998 to 31 December 1999 | 49.17 |
| **Total** | **55.73** |

Given that accounting depreciation by AlintaGas for the year ending 30 June 1997 was $66.3 million,[134] the depreciation estimate provided by Epic Energy may underestimate the accounting depreciation, at least for the period during which the DBNGP remained owned by AlintaGas. At the time of publication of this Draft Decision, the Regulator was not in a position to determine accounting depreciation and for the purposes of Draft Decision the depreciation estimate provided by Epic Energy is utilised.

Given the above estimates of capital expenditure and depreciation, the depreciated actual cost of the DBNGP determined on the basis of the book value at 31 June 1997 is $1030.2 million as at the 31 December 1999.

The Regulator also sought to estimate a DAC value on the basis of the actual cost of the DBNGP and depreciation charges levied on persons directly or indirectly using the pipeline services though tariffs for either delivery of gas or provision of gas transmission services.

The history of third-party tariff arrangements for gas transmission via the DBNGP is summarised in the following table.

**History of third-party tariff arrangements for gas transmission via the DBNGP**

| Period | Pipeline Owner | Third Party Tariff Arrangements |
|---|---|---|
| 1986 to 1994 | SECWA | No regulated third party transmission tariffs. |
| 1995 to 25 March 1998 | AlintaGas | Alcoa contact tariff.<br>*Gas Transmission Regulations 1994* tariffs. |
| 25 March 1998 to present | Epic Energy | Alcoa contract tariff.<br>*Dampier to Bunbury Pipeline Regulations 1998* tariffs |

Prior to 1 January 1995 all gas transportation through the DBNGP was undertaken by SECWA predominantly on its own behalf and for sale of gas at the point of delivery to gas

[133] Spreadsheet accompanying letter from Epic Energy to Office of Gas Access Regulation: Basis of Estimate of Depreciated Historical Cost, 9 August 2000, Epic Energy reference DW/jp.

[134] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 131.

users.[135] Although a separate transmission business unit carried out the gas transmission activities of SECWA and notional payments were made to this business unit for the transmission activities, there were no regulated third-party transmission tariffs *per se*.

From 1 January 1995 to 25 March 1998, a transmission business unit of AlintaGas provided gas transmission services to third parties that comprised Alcoa, AlintaGas's "other business" and other parties.

From 1 January 1995, third parties other than Alcoa (including the AlintaGas "other business") entered into contracts for gas transmission under the *Gas Transmission Regulations 1994* (prior to 25 March 1998), and under the *Dampier to Bunbury Pipeline Regulations 1998* (subsequent to 25 March 1998). These regulations included a specification of tariffs. After 25 March 1998, contracts entered into under the *Gas Transmission Regulations 1994* assumed the terms and conditions, and tariffs, of the *Dampier to Bunbury Pipeline Regulations 1998*. The *Gas Transmission Regulations 1994* and the *Dampier to Bunbury Pipeline Regulations 1998* specified transmission tariffs that included a specific component for depreciation of the DBNGP assets.

The Regulator has estimated a DAC value on the basis of the following information:

- Records of capital expenditure for the DBNGP contained in SECWA Annual Reports for the periods 1982/83 to 1989/90 and 1991/92.
- Estimates of Optimised Replacement Costs for assets the subject of capital expenditure in 1990/91 and 1991/92. Estimated ORC values were provided by Epic Energy.[136] (No other source could be found for capital expenditure during these years and it is considered reasonable to use an Optimised Replacement Cost as a proxy).
- Data for Capital Expenditure for 1994/95 and subsequent periods, provided by Epic Energy and derived from various other sources including the Information Memorandum for the sale of the DBNGP and GTR Price Redetermination Reports.
- Past capital recovery charges and depreciation allowances estimated from information provided by Epic Energy.[137]

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[135] There were two third party access contracts entered into prior to the advent of the Gas Transmission Regulations 1994.

[136] Epic Energy, 16 June 2000. Letter to Office of Gas Access Regulation: Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline: Request for Information dated 11 May 2000. Epic Energy reference DW.

[137] Epic Energy, 22 February 2001. Letter the Office of Gas Access Regulation re DBNGP Access Arrangement Information Requests numbers 5-2, 9, 14, 18.

**Estimated capital expenditure and capital recovery for the DBNGP to 31 December 1999**

| Period | Capital expenditure | Capital recovery |
|---|---|---|
| 1982/83 | 344.6 | 0 |
| 1983/84 | 436.3 | 0 |
| 1984/85 | 297.2 | 19.3 |
| 1985/86 | 71.2 | 21.2 |
| 1986/87 | 16.5 | 25.0 |
| 1987/88 | 12.6 | 25.3 |
| 1988/89 | 9.0 | 27.8 |
| 1989/90 | 0 | 32.1 |
| 1990/91 | 132.0 | 36.1 |
| 1991/92 | 52.0 | 39.2 |
| 1992/93 | 0 | 45.6 |
| 1993/94 | 0 | 49.4 |
| 1994/95 | 3.2 | 56.0 |
| 1995/96 | 11.8 | 64.2 |
| 1996/97 | 51.5 | 71.0 |
| July 97 to Dec 99[138] | 169.5 | 221.1 |
| **Total** | **1607.4** | **733.4** |

The estimated DAC value based on actual capital expenditure and recovery is therefore $874.0 million as at 31 December 1999. This value should be regarded as approximate as it is based on general assumptions as to, *inter alia*, an average interest rate underlying annuity charges for capital returns, timing of capital expenditures and pipeline throughput. Also, the amounts of capital recovery exclude amounts related to some laterals and metering facilities. The recovery of capital for these facilities has typically occurred in accordance with specific contractual arrangements between the DBNGP owner and Users.

#### 5.3.4.3 Depreciated Optimised Replacement Cost

Paragraph 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.

A Depreciated Optimised Replacement Cost (DORC) valuation of assets ignores (at least in principle) the history of the assets and of depreciation and attempts to determine a value as if a set of assets necessary to provide a specified current and future service potential of the existing assets were being constructed “today” in the most cost effective manner. There are two core components to a DORC valuation:

[138] 1999 capital expenditure is assumed to include all capital expenditure on the Stage 3A Expansion.

- determination of the efficient cost (the Optimised Replacement Cost) of constructing a set of assets (which may not be the same as the existing assets but rather represents an optimised set of assets given current technology and the market for services) to provide a given level of service; and
- depreciation of the Optimised Replacement Cost to correct for the age of the current assets and thereby matching the future service potential of the "new" assets with the future service potential of the existing assets.

The determination of a DORC value is undertaken by the following general steps.

- optimisation – determination of the optimal configuration and sizing of assets to provide a specified level of service;
- costing – determination of a modern engineering equivalent for each asset in the optimised system and a cost for purchase/construction of each asset; and
- depreciation, usually by a straight line methodology taking account of the age of the existing assets and assuming a standard economic life for each asset.[139]

In practice, the determination of a DORC value involves many matters of judgement including the appropriate service capacity of the optimised assets, appropriate optimisation of assets, assumptions as to whether asset construction occurs as a staged process or a single event, assumptions as to the extent of construction works necessary (particularly assumptions as to whether construction occurs as a "greenfields" or "brownfields" development[140]), and the depreciation methodology and assumptions used. In regard to these matters, there is no "correct" methodology or set of assumptions for a DORC valuation, but rather the appropriate methodology and assumptions will depend upon the particular context and objectives of the valuation. For example, if the primary concern in determining a DORC valuation is to replicate the capital costs that may be faced by a new entrant to the market, then a greenfields assumption may be appropriate as a new entrant may not necessarily be able to utilise existing infrastructure. Conversely, if the primary concern in determining a DORC valuation is to value existing assets consistent with the remaining life of assets and generating sufficient revenue to cover costs to the Service Provider of efficiently replacing worn out assets, then a brownfields assumption may be appropriate as this corresponds more closely to the environment within which replacement investment occurs and the costs of such replacement.

Epic Energy has indicated a DORC valuation of the DBNGP assets to be $1,368.4 million as at 1 January 2000.[141] 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.[142] Epic Energy supported this staged approach with an argument that it is consistent with that used by the Federal Communications Commission in its decision *In the*

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[139] ACCC, May 1999. Draft Statement of Principles for the Regulation of Transmission Revenues, p 42.

[140] A "brownfields" approach assumes that existing infrastructure not directly forming part of the assets are in place, where such infrastructure may include roads, power supplies, easements, rights of way, etc.). A "greenfields" approach assumes that such infrastructure does not exist and the costs of provision must be included in the valuation.

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

[142] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 7.

*Matter of Implementation of the Local Competition Provisions in the Telecommunications Act of 1996; Interconnection between Local Exchange Carriers and Commercial Mobile Radio Service Providers* Release Number FCC 96-325 (11 FCC Rdc 15499; 1996 FCC LEXIS 4312; 4 Comm. Reg. (P & F) 1) dated August 1996.[143] 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 and "optimised" pipelines.

A summary of replacement costs, optimised replacement costs, asset lives and DORC values in Epic Energy's DORC valuation of the DBNGP for pipeline assets is as follows.[144]

**Epic Energy DORC value of DBNGP assets**

| Category of Asset | Optimised replacement cost ($million) | Asset life (years) | DORC ($million) |
|---|---|---|---|
| Pipelines | 930.95 | 100 | 904.29 |
| Compression | 367.88 | 57 | 253.05 |
| Meter stations | 38.33 | 71 | 36.18 |
| Associated facilities, insurance and interest | 181.26 | 50 | 160.45 |
| Land and linepack | 14.84 | -[145] | 14.46 |
| **Total** | **1,527.93** | | **1,368.43** |

The Regulator had Epic Energy's DORC valuation reviewed by Connell Wagner Pty Ltd (Connell Wagner) 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.

Connell Wagner assessed the DORC valuation under the "new entrant" premise whereby the Optimised Replacement Cost is estimated on the basis of the costs that would be incurred by a new entrant to the gas transmission market in constructing a pipeline system using modern technology and current best-construction practice to supply the quantity of gas transmission currently forecast for the DBNGP system, at current service standards, and as a brownfields development. This was different to the approach used by Epic Energy, which was based on matching the staged development of the pipeline system that has actually taken place (initial design as a free-flow pipeline and subsequent addition of compression in four stages) under an assumption of a greenfields development.

Connell Wagner commented on several potential deficiencies of Epic Energy's Optimised Replacement Cost and DORC estimates. In view of these potential sources of inaccuracy in Epic Energy's DORC valuation, Connell Wagner advised that this value might overstate a "new-entrant" and "fully optimised" Optimised Replacement Cost by an amount in the order

[143] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, p 7.

[144] Epic Energy DORC calculation spreadsheet submitted with Response to Information Request 1, 16 June 2000.

[145] Land and linepack were assumed to be non-depreciable assets.

of $269 million. Reduction of the Optimised Replacement Cost by this amount and corrections to the assumed asset lives for the purposes of depreciation have the effect of reducing the DORC value by $280 million.

For the purposes of this Draft Decision the Regulator has decided to value the DBNGP assets at 31 December 1999 as including the Stage 3A pipeline expansion in total. This requires transferring some of Epic Energy's forecast Capital Expenditure into the initial asset valuation. With this adjustment, the Epic Energy estimated DORC value would be $1,493.6 million. With the adjustment for Stage 3A Capital Expenditure and the reduction in the Optimised Replacement Cost as already indicated, the Epic Energy DORC value is revised to $1,227.41 million, detailed as follows.

**Revised Epic Energy DORC value of DBNGP assets**

| Category of Asset | Optimised replacement cost ($million) | Asset life (years) | DORC ($million) |
|---|---|---|---|
| Pipelines | 739.75 | 70 | 764.11 |
| Compression | 296.38 | 30 | 256.24 |
| Meter stations | 32.03 | 50 | 31.87 |
| Associated facilities, insurance and interest | 175.88 | 50 | 160.34 |
| Land and linepack | 14.84 | -[146] | 14.84 |
| **Total** | **1,258.88** | | **1,227.41** |

The Regulator did not make engineering estimates of Optimised Replacement Cost and DORC values for the purposes of this Draft Decision. The Regulator did, however, consider the Optimised Replacement Cost and DORC values 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.[147] The principal assumptions underlying this valuation were as follows:

- Optimisation was based on a service capacity based on capacity as at July 1997 and known expansion to 31 December 1997, resulting in the optimised system being the same as the existing system of the time in respect of the pipeline diameter for the Dampier to Kwinana trunkline and the number and size of compressor stations, with the exception of compressor station CS1 for which capacity was reduced from 9 MW to 4 MW.
- Optimisation did not consider total reconfiguration of the manner in which services are delivered, or any dramatic redesign of processes or networks.
- Easement costs and land management issues (right-of-way acquisition, native land title matters, land access negotiation, etc.) were excluded from the valuation, consistent with a "brownfields" valuation assumption.

[146] Land and linepack were assumed to be non-depreciable assets.

[147] 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.

- The Geraldton lateral and the section of pipeline south of Clifton Road were excluded from the valuation, both of these assets not being sold as part of the DBNGP.
- Minor ongoing capital items such as computer equipment, vehicles, office/workshop equipment, furniture, spare parts etc. were not examined in detail or optimised.
- Australian Standard AS 2885 was used as a basis for optimisation.
- Lateral pipelines were sized according to forecast throughput.
- The communication system was taken to be a satellite system rather than a telemetry system as currently exists.
- The SCADA was upgraded to reflect current technology.
- Costs did not include sales tax and customs duty.
- Costs did not include the owner's financing costs.

This basis for determination of the Optimised Replacement Cost was broadly similar to that used by Epic Energy for the proposed Access Arrangement, involving the optimisation of an asset without any fundamental changes to the gross characteristics of that asset.

The Optimised Replacement Cost and DORC values derived in 1997 were as follows.

**Price Waterhouse 1997 DORC value of DBNGP assets[148]**

| Category of Asset | Optimised Replacement Cost ($million) | Asset life (years) | Depreciated life (years) | DORC at 31 Dec 1997 ($million) |
|---|---|---|---|---|
| Pipeline supply and construction | 941.8 | 60 | 12.5 | 745.6 |
| Lateral supply and construction | 37.8 | 60 | 12.5 | 30.1 |
| Compressor stations | 299.2 | 60 | 12.5 | 236.8 |
| MLV stations | 27.5 | 60 | 12.5 | 21.8 |
| Scraper stations | 11.4 | 50 | 12.5 | 9.1 |
| Metering stations | 28.4 | 60 | 12.5 | 22.5 |
| SCADA | 8.4 | 10 | 2.5 | 6.3 |
| Communication | 15.3 | 10 | 2.5 | 11.5 |
| Pipeline purge and first fill | 3.9 | 60 | 12.5 | 3.1 |
| Maintenance bases and equipment | 10.8 | 60 | 12.5 | 8.6 |
| Vehicles | 5.4 | 4 | 0.5 | 4.7 |
| Computers | 2.0 | 2 | 0.5 | 1.5 |
| Maintenance plant and equipment | 3.2 | 10 | 2.5 | 2.4 |
| Operation base/control centre | 3.6 | 10 | 2.5 | 2.7 |
| Project insurance | 6.1 | 20 | 12.5 | 2.3 |
| Spares | 6.0 | 20 | 12.5 | 2.3 |
| Owners cost | 35.3 | 20 | 12.5 | 13.2 |
| Total | 1446.1 | | | 1124.5 |

[148] Dampier to Bunbury Natural Gas Pipeline Gas Pipeline Sale Steering Committee, Data Room Question and Answer Sheet, Sequential Question No. 29, 16 February 1998.

While the above Optimised Replacement Cost valuation was undertaken as a "high level" study, the Regulator considers the value to be reasonably accurate given the inherent subjectivity and uncertainty in the Optimised Replacement Cost valuation methodology.[149] The Regulator's principal concern with the valuation relates to the derivation of the DORC based on an assumption of useful lives of the principal pipeline assets of 60 years, which is less than the useful life of 70 to 80 years typically assumed for such assets. The Regulator considers appropriate assumptions as to useful asset lives to be 70 years for the principal pipeline assets, 50 years for metering assets and 30 years for compression assets.

An asset valuation as at 31 December 1999 was derived by the Regulator from the 1997 Optimised Replacement Cost valuation by escalating the Optimised Replacement Cost value to account for inflation, depreciating over a greater asset age (14.5 years) with a longer useful asset life for principal assets, and adding capital expenditure (corrected for inflation and depreciation) in the years 1998 and 1999 and associated with the Stage 3A pipeline expansion. A valuation of $1,233.7 million was derived as follows.

[149] The report for the Optimised Replacement Cost valuation indicates an accuracy of ±15 percent. (CMPS&F Pty Limited, 1997, Dampier to Bunbury Natural Gas Pipeline Optimised Replacement Cost, document no. PW0972/OLW390 prepared for Price Waterhouse)

**Asset valuation at 31 December 1999 based on the 1997 Optimised Replacement Cost**

| Category of Asset | Optimised Replacement Cost[150] ($million) | Asset life (years) | Depreciated life (years) | DORC at 31 Dec 1999 ($million) |
|---|---|---|---|---|
| Pipeline supply and construction | 974.0 | 70 | 14.5 | 772.2 |
| Lateral supply and construction | 39.1 | 70 | 14.5 | 31.0 |
| Compressor stations | 309.4 | 30 | 14.5 | 159.9 |
| MLV stations | 28.4 | 70 | 14.5 | 22.5 |
| Scraper stations | 11.8 | 70 | 14.5 | 9.3 |
| Metering stations | 29.4 | 50 | 14.5 | 20.9 |
| SCADA | 8.7 | 15 | 4.5 | 6.1 |
| Communication | 15.8 | 15 | 4.5 | 11.1 |
| Maintenance bases and equipment | 11.2 | 70 | 14.5 | 8.9 |
| Vehicles | 5.6 | 10 | 2.5 | 4.2 |
| Computers | 2.1 | 2 | 0.5 | 1.6 |
| Maintenance plant and equipment | 3.3 | 10 | 4.5 | 1.8 |
| Operation base/control centre | 3.7 | 50 | 4.5 | 3.4 |
| Project insurance | 6.3 | 30 | 14.5 | 3.3 |
| Owners cost | 36.5 | 30 | 14.5 | 18.9 |
| **Total, depreciable assets** | **1485.3** | | | **1074.9** |
| Pipeline purge and first fill | 4.0 | | | 4.0 |
| Spares | 6.2 | | | 6.2 |
| **Total, non-depreciable assets** | **10.2** | | | **10.2** |
| **Total** | **1495.5** | | | **1085.2** |
| Depreciated capital expenditure 1998 and 1999[151] | | | | 148.5 |
| **Asset Value** | | | | **1233.7** |

### 5.3.4.4 Other Valuation Methodologies

Paragraph 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.

In documentation submitted to the Regulator in addition to the proposed Access Arrangement and Access Arrangement Information, Epic Energy provided information on asset valuations derived by two valuation methodologies other than those relating to paragraphs 8.10(a) and 8.10(b) of the Code:

- an Optimised Deprival Value; and

[150] Escalated for inflation on the basis of Australian Bureau of Statistics CPI measures of 120 for December 1997 and 124.1 for December 1999.

[151] Capital expenditure includes all expenditure for the Stage 3A enhancement, even though Epic Energy considered some of this expenditure to occur in 2000. Refer to section 5.4.4 of this Draft Decision for a discussion of the Regulator's considerations in respect of Epic Energy's forecast Capital Expenditure.

- an "imputed Capital Base".

Epic Energy's valuations of the DBNGP by these methodologies are discussed below.

Epic Energy has also proposed that the DBNGP be valued for regulatory purposes at the cost of purchase of the assets by Epic Energy. The "cost of purchase" is also discussed below as an alternative valuation methodology.

**Optimised Deprival Value**

The Optimised Deprival Value of an asset is the value of an asset to the owner calculated in terms of the loss that would be incurred by the owner if deprived of the asset. For the purposes of this Draft Decision, the Optimised Deprival Value is defined as the lesser of the optimised replacement cost of the asset and the valuation of the asset in terms of the net present value of financial returns to the asset (on a cash flow basis) over the remaining economic life of the asset. This definition is consistent with Bonbright's "value to the owner" which is the lesser of the current replacement cost (arguably the Optimised Replacement Cost) and the income generating capacity of the asset.[152,153]

For the purposes of estimating an Optimised Deprival Value, Epic Energy determined a net present value of future cash flows over the remaining economic life of the DBNGP under the following assumptions.[154] Epic Energy's determination is summarised as follows:

- The initial tariffs and the path of future tariffs for Users with Access Arrangement contracts are those referred to by Epic Energy as being part of the regulatory compact with the Western Australian Government, being $1.00/GJ for gas delivered at 100 percent load factor to the Perth metropolitan area and about $1.08/GJ for gas delivered to areas south of the Perth metropolitan area, increased annually at 67 percent of the change in the consumer price index.
- The tariffs for gas transportation services to Alcoa of Australia are those tariffs specified in the transportation contract between Alcoa and Epic Energy.
- Annual quantities of gas transported under Access Arrangement contracts were assumed to be as forecast in the Access Arrangement Information for the five-year Access Arrangement Period and thereafter the quantity of gas forecast for the fifth year of the Access Arrangement Period. Quantities transported under the Alcoa contract were as forecast for a period of twenty years and thereafter assumed to remain static at the quantity of the twentieth year.
- Capital Costs and Non-Capital Costs were those of the proposed Access Arrangement, extrapolated for the period beyond the fifth year of the Access Arrangement Period. Allowances were made for the replacement of major component assets (for example, compressors) at the ends of their technical lives, but no allowance was made for expenditures that would expand pipeline capacity.

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[152] Bonbright, J.C., 1937. *The Valuation of Property*, The Mitchie Company.

[153] An Optimised Deprival Value is also sometimes defined as the less of the net present value of cash flows from an asset and the Depreciated Optimised Replacement Cost, on the basis that if an owner of asset is compensated for the cost of an entirely new asset then the owner would be better off than when previously owning a partly depreciated asset. Which of the two definitions is appropriate will vary with the context of the valuation and the situation of the asset in question.

[154] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, pp 10, 11.

- The discount rate is equal to a real pre-tax cost of capital in the range of 7.0 to 8.5 percent.

According to the assumption as to the discount rate, the net present value of cash flows was estimated at $1,700 million (discount rate of 7 percent) or $1,550 million (discount rate of 8.5 percent).

The Optimised Replacement Cost of the DBNGP was estimated by Epic Energy to be $1,527.9 million, as described above in relation to Epic Energy's DORC valuation of the pipeline (page 129 of this Draft Decision).

Epic Energy estimated an Optimised Deprival Value at $1,527.9 million, being the lesser of the net present value of expected future cash flows and the Optimised Replacement Cost, in this case equal to the Optimised Replacement Cost.

The Regulator did not estimate an Optimised Deprival Value as part of the assessment of the proposed Access Arrangement, but did consider the in-principle merits of the valuation methodology as well as Epic Energy's estimate of the value (section 5.3.4.5 of this Draft Decision).

**Imputed Capital Base**

Epic Energy estimated a value of an "imputed Capital Base" as the value of the Capital Base that is consistent with a predetermined acceptable Reference Tariff for the Access Arrangement Period.[155] Epic Energy derived the value corresponding to the Reference Tariff set out in the proposed Access Arrangement, assuming the same gas quantity forecasts, Non-Capital Costs and Capital Costs proposed by Epic Energy for the Access Arrangement Period, and using a cost of service methodology. No information was provided on the calculation or on the assumptions as to asset depreciation for the purpose of this valuation, although the Regulator assumes that an annuity depreciation methodology was used. The valuation derived by Epic Energy using this methodology was $1,750 million.

The Regulator notes that given that Epic Energy has purportedly based the Reference Tariff on the tariffs of Schedule 39 of the DBNGP Asset Sale Agreement, this valuation is somewhat at variance from the statement by Epic Energy in the Access Arrangement Information that:[156]

> Epic Energy's determination of the tariffs in Schedule 39, and of the future tariff path, were consistent with the approach that had been taken by the Government's own advisors. These determinations used the depreciated optimised replacement cost valuation of the Pipeline prepared by the engineering consultants CMPS&F and used by price Waterhouse in its August 1997 report. Furthermore, they used forecasts that had been provided by the Government, and they used principles consistent with those adopted by Price Waterhouse for estimation of the cost of capital.

On this basis, it would be expected that Epic Energy's proposed Reference Tariff would be consistent with an Initial Capital Base close to the DORC valuation of the pipeline, being in the approximate range $1.2 billion to $1.3 billion. The Regulator has not further investigated this discrepancy.

**Cost of Purchase**

Epic Energy has proposed an Initial Capital Base for the DBNGP assets of $2,570.34 million as at 31 December 1999, being the cost to Epic Energy of purchase of these assets as at

[155] Epic Energy Additional Paper 5: Code Compliance, Attachment 4: Initial Capital Base Valuation Methodologies, pp 10, 11.

[156] Access Arrangement Information, p 25.

25 March 1998, with adjustment to account for depreciation and capital expenditure in the period from 25 March 1998 to 31 December 2000.

As indicated in section 5.3.2 of this Draft Decision, Epic Energy supported the proposed valuation of the Initial Capital Base with an indication that the purchase price of the DBNGP is justified by being consistent with the net present value of cash flows given the future tariffs proposed at the time of the purchase, and a recovery of the invested capital over the physical life of the assets at the same future tariffs.

The Regulator is of the view that Epic Energy has not demonstrated that the purchase price is consistent with a net present value of cash flows from the assets, or consistent with a recovery of invested capital over the physical life of the assets. The primary reason for this view is that the calculations presented by Epic Energy were based on forecasts of throughput quantities that are substantially in excess of the current capacity of the pipeline system, and no allowance has been made in the calculations for the capital expenditure necessary to accommodate these quantities. As such, the Regulator does not consider Epic Energy to have substantiated the view that the purchase price for the DBNGP represents a reasonable market valuation of the assets, nor for there to be any reason to consider a reasonable market valuation to be in excess of a DORC valuation.

#### 5.3.4.5 Assessment of Alternative Valuation Methodologies

Paragraph 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).

Estimated values of the DBNGP assets using different valuation methodologies and assumptions are as follows. Advantages and disadvantages of each valuation methodology are discussed below.

**Alternative valuations of the DBNGP Initial Capital Base**

| Basis of valuation | Asset value ($million at 31 Dec 1999)) |
|---|---|
| DAC (Epic Energy, based on depreciated purchase costs) | 2,446.1 |
| DAC (Epic Energy, based on depreciated historical cost) | 1,331.5 |
| DAC (Regulator, based on indicative book value of assets at 30 June 1997 and capital expenditure and depreciation data provided by Epic Energy) | 1,030.2 |
| DAC (Regulator, based on actual historical cost, including Stage 3A expansion costs, and estimated returns of capital from third-party users.) | 874.0 |
| DORC (Epic Energy)[157] | 1,493.6 |
| DORC (Regulator, based on revised Epic Energy DORC valuation) | 1,227.4 |
| DORC (Regulator, based on 1997 Optimised Replacement Cost and capital expenditure, depreciation and inflation to December 1999) | 1,233.7 |
| Optimised deprival value (Epic Energy)[158] | 1,527.9 |
| Imputed Capital Base for proposed tariffs (Epic Energy)[159] | 1,750.0 |
| Cost of purchase (Epic Energy) | 2,570.3 |

## Advantages and Disadvantages of a DAC Valuation of the Initial Capital Base

An in-principle advantage of a DAC valuation is that it can be based on actual accounting records and therefore relies less on the individual judgement of the person undertaking the valuation than other valuation techniques and is auditable. Thus there should be little or no argument about the valuation using this methodology, although there may of course still be arguments about the appropriateness of the methodology. This is, however, dependent upon adequate records of initial expenditure, historical returns to the capital assets being valued and historical depreciation of the assets being valued. Such records may not exist in some situations, as has been found to be the case for gas transmission and distribution systems in Victoria where the current businesses of Service Providers were separated from a larger business and separate records of returns and depreciation had not been maintained for the relevant groups of assets.[160] Although in such cases estimates of DAC values could be made by making assumptions as to the attribution of returns to particular assets and depreciation, the resultant estimates were highly sensitive to the assumptions made and the resultant ranges of DAC estimates were too broad to be useful in assigning particular asset values.

For the DBNGP, some historical records are available as to the depreciation of the pipeline for accounting purposes, although there may be some inconsistency between this “book” depreciation and actual return of capital to the asset owners. For this reason, the DAC values estimated as part of this Draft Decision and on the basis of 1995 or 1997 book values are

[157] Corrected to include all Capital Expenditure associated with the Stage 3A pipeline expansion.

[158] Epic Energy Additional Paper 5, Attachment 4.

[159] Epic Energy Additional Paper 5, Attachment 4.

[160] Victorian Principal Transmission System and Western Transmission System as described in the Final Decision of the ACCC on the relevant Access Arrangements (1998).

considered to possibly overestimate a true DAC value, however insufficient information was available to the Regulator to verify this.

A second advantage of a DAC valuation of the Initial Capital Base is that it is calculated from the actual construction cost of the assets and subsequent returns of capital by depreciation. Thus the DAC value arguably reflects the unrecovered capital costs of providing the services. However, a DAC value does not take into account changes in the value of funds and assets as a result of inflation. Investors can reasonably expect returns to capital and returns of capital to maintain value in real terms. By not accounting for inflation, a DAC value tends to reflect an over-estimate of past real returns of capital to investors. The older the assets, the more biased a DAC value is in representing the real capital cost of the assets due to not accounting for inflation.

Furthermore, and as discussed above in relation to derivation of DAC values for the DBNGP (section 5.3.4.2 of this Draft Decision), depreciation allowances evident from accounting statements do not necessarily provide an accurate representation of "true" depreciation of assets. Accounting records are maintained for purposes other than monitoring returns of capital. Depreciation allowances are typically determined on the basis of considerations other than an explicit recovery of invested capital, such as manipulation of taxation liabilities. There is no reason to presume that accounting depreciation (and hence the book value of assets) will bear any relation to the explicit or implicit recovery of invested capital through prices of services.

Although a DAC value to some extent reflects actual capital costs in providing a service, these costs may not reflect the current most efficient means of providing a service due to failure to take into account technological change. From a forward-looking perspective in regulation, a DAC valuation of assets means that tariffs are not being determined on the basis of efficient capital costs and "best-practice" in provision of services, or take into account redundancy or obsolescence of assets. As a consequence, a revenue requirement calculated on the basis of an historical cost of assets does not necessarily bear any relation to the Service Provider's future revenue requirement for the maintenance and replacement of capital assets.[161] 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.[162] Indeed, as noted by the Victorian Office of the Regulator General, assigning a value to the Capital Base on the basis of historical costs and returns has little justification in terms of economic theory, which is concerned with creating the incentives for efficient forward-looking decision making rather than unravelling the past.[163]

The disadvantage of a DAC value arising from the failure to account for inflation may be roughly offset by adjustment for inflation. An "inflation adjusted capital cost" or "inflation adjusted historic cost" can be estimated by revaluation of the assets using a broad inflation indicator such as CPI statistics. Such a valuation is still, however, subject to the availability of relevant financial records and has the disadvantage of potentially not reflecting efficient capital costs of service provision.

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[161] Ergas, H., 2000. Some economic aspects of asset valuation, paper presented at the ACCC Asset Valuation Forum 16 June 2000.

[162] Ergas, H., 2000. Some economic aspects of asset valuation, paper presented at the ACCC Asset Valuation Forum 16 June 2000.

[163] Office of the Regulator General (Victoria), 1998, Final Decision on the Multinet, Westar and Stratus distribution systems.

Regardless of the value that may be ascribed to capital assets in a hypothetical competitive market for gas transportation, a regulated Service Provider will, over the long term, have a regulatory Capital Base valued at approximately the inflation adjusted capital cost. Once the original assets that are reflected in the value of the Initial Capital Base are fully depreciated the Capital Base will comprise only assets purchased after commencement of regulation under the Code. The Code provides for a return on these assets on the basis of an inflated written-down actual cost, minus any value attributable to redundant assets. Valuation of existing assets at an inflation adjusted capital cost is therefore generally consistent with the treatment under the Code of Capital Expenditure that occurs subsequent to acceptance of the proposed Access Arrangement. Consistency with long-term future valuation of assets under the Code is not, however, in itself necessarily good reason not to consider alternative valuation methodologies for the Initial Capital Base.

**Advantages and Disadvantages of a DORC Valuation of the Initial Capital Base**

There are three commonly cited advantages of a DORC valuation of assets:

i. a DORC valuation would result in tariffs that replicate tariff outcomes in a competitive market;

ii. determination of tariffs on the basis of a DORC valuation of assets will avoid tariff shocks for Users at times of asset replacement; and

iii. an asset value greater than DORC would create incentives for inefficient duplication of system assets by other Service Providers.

Arguments for these advantages are examined as follows.

The argument that tariffs based on a DORC valuation of assets would replicate the tariff outcomes of a competitive market arises from a consideration 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 or when the need arises. Consequently the Service Providers in the competitive market would be setting prices on a similar basis of capital costs. By the same argument, tariffs corresponding to an asset value that is greater than the DORC value would return the Service Provider a revenue stream more than sufficient to maintain provision of services over the long-term, and therefore could be considered to include monopoly rents.

The argument that a DORC value is the value that would be ascribed to an asset in a competitive market depends, however, upon what is considered to be the benchmark "competitive market". If the Service Provider operates in a contestable market where the only barrier to entry is the cost of constructing new assets, then the maximum that the existing monopoly provider could charge for services without attracting competition would be tariffs consistent with a DORC value of assets.[164] If the benchmark is a hypothetical competitive market with numerous Service Providers with assets of different ages, the comparison becomes far more complex. Factors such as competitive pressures, uncertainties over future returns, and technological change may result in prices reflecting returns on asset values that, at different times, may be less than or greater than DORC values.

[164] Note that if the cost of fixed assets was the only barrier to entry to the market then the market would in principle be contestable and no regulation would be necessary to prevent the Service Provider exploiting a monopoly position. there are, however, barriers to entry to the market in addition to fixed costs, such as regulatory barriers and natural monopoly (economies of scale) advantages in service provision.

It is a commonly cited argument for a DORC valuation that, if replacement of the assets will become necessary, then basing tariffs on a DORC valuation of assets reduces the likelihood of sudden increases in tariffs when replacement is undertaken, resulting in greater tariff certainty and predictability for Users. However, this argument for valuing an asset at a DORC value, as opposed to some lesser value, has little in-principle or practical justification.

On an in-principle level, it is difficult to see how Users will be made better off by paying higher tariffs in the present just to avoid an increase in tariffs in the future, when they will pay the same future tariffs in any case. This is particularly the case where assets are relatively new and replacement of major assets would not occur for some considerable time.

In practice, it is unlikely that a gas pipeline and associated assets would be replaced in a single event, or even in a closely spaced sequence of events. The different economic and technical lives of various assets making up a pipeline, and even various parts of the pipeline, would result in replacement being undertaken as multiple events over long periods. An initial setting of tariffs for an existing pipeline with an Capital Base less than a DORC valuation may lead to a necessity of raising tariffs over time, but significant tariff shocks are unlikely. Furthermore, tariffs may be smoothed over time to take into account "lumpy" capital investment without having to establish a Capital Base that is higher than would otherwise be considered appropriate.

Notwithstanding the lack of justification of a DORC valuation of assets provided by the argument that such a valuation would reduce tariff shocks at the time of replacement investment, consideration of the need to finance replacement investment is a relevant consideration in determining the advantages of a DORC valuation. The most direct test of an asset valuation concept is whether it is consistent with generating a revenue stream sufficient for capital maintenance and replacement investment.[165] Under this premise, a "current" value such as DORC is, in principle, more appropriate than a valuation based on historical cost as it accounts for the efficient capital costs of replacing the service potential of assets as they reach the end of useful lives with "optimised" assets under current technology. From this perspective, a DORC valuation may be regarded as a "technology adjusted" current cost accounting value of assets.[166] This value is regarded as consistent with the price that a firm with a certain service requirement would pay for the existing "second-hand" assets with their remaining service potential, higher operating costs, and (old) technology, given the alternative of installing new assets which embody the latest technology, and which would generally have lower operating costs, and which will have a greater remaining service potential.[167]

Finally, in regard to the avoidance of inefficient duplication of assets, a DORC valuation of the Initial Capital Base arguably has the advantage, in principle, of not resulting in tariffs that are so high as to motivate inefficient duplication of pipeline assets by another Service Provider. Correspondingly, a tariff derived from a DORC valuation of the Capital Base would provide opportunities to enter the market and secure market share only to those Service Providers with efficiently constructed assets. This is the reason for establishing an

[165] Ergas, H., 2000. Some economic aspects of asset valuation, paper presented at the ACCC Asset Valuation Forum 16 June 2000.

[166] In the Draft Decision for the Moomba to Sydney Pipeline (19 December 2000, pp 25, 26), the ACCC noted that a depreciated replacement cost (no optimisation) is precisely the regulatory asset value emerging from a current cost accounting based framework. A DORC value can be regarded as a current cost accounting value corrected for asset write downs to reflect redundant assets or technologies.

[167] ACCC, May 1999. Draft Statement of Principles for the Regulation of Transmission Revenues, p 40.

upper limit on the Initial Capital Base of a DORC value. However, this argument ignores the likelihood that there are likely to be substantial barriers to entry to the market other than the capital costs of assets, and hence values well in excess of DORC may still not necessarily lead to inefficient duplication of assets.[168] Further, there is no justification in this argument for not adopting values of the Capital Base at less than the DORC value.

The principal disadvantage of a DORC valuation of the Initial Capital Base is that should the value so derived exceed the written down value of actual investment in assets (i.e. the DAC value or an inflated actual capital cost), then the resultant tariffs would conceivably provide windfall profits to the Service Provider at the expense of Users. This would occur where the historical depreciation of assets has exceeded the depreciation assumed in calculation of the DORC value. Common practice in calculation of DORC values is to assume straight-line depreciation over the technical life of assets. In practice, Service Providers may, and do, depreciate assets for accounting and/or taxation purposes using an accelerated rate of depreciation. This is partly the cause for DORC values of assets generally exceeding the written down historic cost of those assets. For the DBNGP, DAC and DORC values are, in the Regulator's view, relatively close at between $1.0 and $1.3 billion and the potential for windfall gains to the Service Provider from a DORC valuation is not expected to be significant.

There are also practical difficulties in arriving at a DORC valuation of assets. A DORC valuation is generally highly subjective. This particularly occurs where the asset being valued is operated at less than capacity. Given that an optimised replacement cost should generally be the most efficient means of replacing assets to provide the same level of service, subjective decisions would need to be made as to whether a replacement cost should be based on assets that are just sufficient to provide the current level of service, or whether some market growth should be allowed for and hence excess capacity accommodated in the replacement costs. Judgement is also often exercised in determining an extent of optimisation of the hypothetical replacement asset, in particular whether the asset should or should not be constrained to be fundamentally the same as the existing system (for example in terms of route and major design parameters). Arguments can be made both ways. An asset valuation based on a DORC value of replacement assets that are fundamentally the same as existing assets may be more likely to generate the revenue necessary to efficiently maintain the asset into the future, as total replacement with a fully optimised asset may not be an efficient means of future service provision given that assets are already in place. Conversely, an asset valuation based on a DORC valuation of a fully optimised asset is more likely to give rise to tariffs that are consistent with the efficient capital costs of a new entrant to the market. Which argument is most relevant for valuation of a gas pipeline depends on the particular context and the objective of valuation. For the DBNGP, it might well be appropriate to give consideration to the revenue requirements for long-term maintenance of the *existing* pipeline assets as the pipeline remains the sole means of transport of gas to the South West of Western Australia. Given this, it would be inappropriate to entirely dismiss the "staged construction" approach to deriving the DORC valuation proposed by Epic Energy and the Optimised Replacement Cost value calculated in 1997 prior to the DBNGP Sale, even though such valuations may not reflect a strictly design of replacement assets.

[168] 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).

Overall, a DORC methodology for valuation of the Capital Base has merit as an upper bound for an asset value, based on the consideration that any higher value might motivate inefficient duplication of the pipeline. A DORC valuation is also, in principle, more likely than a valuation based on historical cost to be consistent with provision of the Service Provider with a stream of revenue commensurate with the requirements for long-term replacement investment in maintaining the service capacity of the assets. A disadvantage of a DORC value is that where a DORC value is substantially greater than the DAC value, a DORC valuation of the Capital Base would give rise to Reference Tariffs that return windfall gains to the Service Provider, however the Regulator does not consider this to be the case for the DBNGP.

**Advantages and Disadvantages of Deprival-Value and Imputed-Value Valuations of the Initial Capital Base**

An Optimised Deprival Value is an estimate of the current value of an asset to the owning business. In a situation of a competitive market for both outputs and assets, the Optimised Deprival Value would equate to the maximum value that the asset would attract in a market sale. As the market value represents the opportunity cost to a business of holding the asset, a reasonable rate of return on the Initial Capital Base valued as the Optimised Deprival Value arguably compensates the business for bearing this opportunity cost. In this sense, a deprival value (or "value to the business") constitutes a current cost accounting valuation method of valuation of assets at the lesser of replacement cost or recoverable amount.[169]

This argument for Optimised Deprival Value as a valuation of the Initial Capital Base breaks down in a situation of regulated tariffs. If the Optimised Deprival Value is determined as the net present value of expected future returns, then there is a circular argument in an industry of regulated tariffs. This arises where regulated tariffs provide for a reasonable rate of return to an Initial Capital Base valued as a net present value of future returns, but the net present value of future returns depends on the regulated tariffs.

Notwithstanding the circularity in asset value and regulated tariffs, an Optimised Deprival Value can be used to derive an asset value that would be consistent with an assumption about future transportation revenue to the pipeline. This approach can be used to derive an asset valuation that would be consistent with views about the reasonable expectations of the asset owner, prior to a regulatory regime coming into effect, and can also be used to derive an Initial Capital Base that would be consistent with the reasonable expectations of Users on the outcome of the pipeline being regulated. It is recognised, however, that the reasonableness of this approach is dependent in turn on the reasonableness of the assumptions that are made about the revenue and costs of future gas transportation. Valuing the Capital Base on the basis of existing tariffs may entrench existing monopoly profits in regulated tariffs.

For the DBNGP, the sale process may have established a basis for expectations of future tariffs and the schedule of tariffs included in the DBNGP Asset Sale Agreement. As such, a deprival value based on considerations of future cash flows and asset replacement costs may have some merit as being representative of the reasonable expectations of the Service Provider. The Epic Energy estimate of the Optimised Deprival Value indicated an estimated present value of cash flows in excess of the Optimised Replacement Cost and Depreciated Optimised replacement Cost of the assets, and as such the forecast tariffs and present value of cash flows became an irrelevant consideration. The advantages and disadvantages of an Optimised Deprival Value revert to those of an Optimised Replacement Cost or DORC value.

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

Similar advantages and disadvantages apply to Epic Energy's "imputed" asset value that, given a tariff determination methodology, is consistent with a predetermined set of tariffs is conceptually similar to a deprival value based on future cash flows. In particular, the reasonableness of an imputed asset value depends upon the reasonableness of the set of tariffs determined *a priori*.

**Advantages and Disadvantages of a Purchase Price Valuation of the Initial Capital Base**

Epic Energy has argued that the purchase price of the DBNGP assets represents a reasonable valuation of the DBNGP Initial Capital Base on the basis of it being the actual investment of the current asset owner in the DBNGP assets, and it being argued that such a valuation is not inconsistent with maintaining a Reference Tariff similar to that set out in the DBNGP Asset Sale Agreement, which may be regarded as establishing future expectations of the Service Provider and Users. In effect Epic Energy argued that an asset valuation at the sale price would not result in either windfall capital gains or losses to the asset owner, and is therefore a *prima facie* fair value.

Previous Australian experience with the sale of gas pipeline assets does, however, indicate that sale prices for such assets may be established well in excess of regulatory assets values that were established prior to sale, as with the Victorian gas transmission and distribution assets. The ACCC has noted that sale prices in excess of predetermined regulatory asset values may reflect a combination of:

- the winner's curse (valuations by the winner erroneously biased upwards by more than other bidders);
- the winner's costs of capital being substantially below that initially proposed by the Regulator; and
- expectations of efficiency savings and benefits of the new owners getting a foothold into the Australian energy market.[170]

The Regulator is not in a position to know the extent to which these factors may apply to the DBNGP, but notes that there is substantial uncertainty as to the extent to which a sale price for assets such as the DBNGP may represent a reasonable valuation of the assets as a stand alone operation. The Regulator is of the view that Epic Energy has not demonstrated that the sale price is consistent with a reasonable market valuation based on potential regulated revenue streams, and hence factors such as those mentioned by the ACCC may apply and limit the appropriateness of the purchase price as a valuation methodology.

**Conclusions on Alternative Methodologies for Valuation of the Initial Capital Base**

The discussion of advantages and disadvantages of different methodologies for valuing a set of pipeline assets indicates that while forming the bounds of the range of asset values explicitly contemplated by the Code, neither DAC nor DORC values are an obvious choice as a valuation methodology. Each has advantages and disadvantages in particular circumstances.

A DORC valuation of the Initial Capital Base has the advantage of being consistent with efficient forward-looking capital costs of providing services and resulting in tariffs for gas transportation that are not so high as to result in inefficient by-pass of existing assets. The primary disadvantage of a DORC valuation is that it may result in over-recovery of the

[170] ACCC, 19 December 2000, Draft Decision Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System, pp 39, 40.

capital costs of providing the service in situations where historical depreciation of assets has occurred at a rate in excess of that assumed for the purposes of estimating the DORC.

A DAC valuation has the advantage of generally being a more readily auditable number than a DORC value, and being a value that reflects actual capital costs in service provision and requires less subjective judgement in determination. However, a DAC value may not represent a reasonable asset value for the Service Provider if no account is made for inflation, nor may it represent a reasonable value to Users if no account is made for redundancy of assets or technological change. A DAC value does not necessarily give rise to a revenue stream that is consistent with future efficient replacement investment in the pipeline assets.

The merit of valuation of the DBNGP at a purchase price is difficult to determine as this price may have been affected by many factors other than a reasonable market value of the assets that is consistent with future regulated revenues and efficient capital investment. Epic Energy has not demonstrated to the satisfaction of the Regulator that the purchase price of the assets represented a reasonable valuation by any conventional valuation methodology.

#### 5.3.4.6 International Best Practice and Industry Competitiveness

Paragraph 8.10(e) of the Code requires that consideration be given to:

> International best practice of pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries.

Precedents for international practice in asset valuation for regulatory purposes are established in the UK and USA, the two countries with the longest histories of regulation of private utility businesses.

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.

Regulators in the UK have also utilised a “market valuation” approach to asset valuation for privatised utility companies, typically involving establishing asset values as the market value of company stocks after some period of trading, 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.[171] The rationale for adopting such valuation methodology has been the “fairness” of allowing investors to earn a reasonable rate of return on original investment.[172] 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.[173]

The Regulator does not regard the proposal by Epic Energy to value the Initial Capital Base of the DBNGP at the cost of purchase of the assets to have any justification in terms of the precedent of market valuation approaches used in the UK. The reason for this view is that the purchase cost of the DBNGP was derived from a private offer that would potentially be subject to biases that would not exist in a stock market value.

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

[172] Price Waterhouse, August 1997. Dampier to Bunbury Natural Gas Pipeline, Regulatory Report on Revenue Requirement and Future Price Path, p 25.

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

The Regulator notes that DORC valuations have been commonly viewed by other regulatory agencies in Australia as "starting points" for asset valuation. A summary of approaches to asset valuation is provided below.

**Initial Capital Base determinations for gas transmission and distribution systems**

| Regulatory Agency | Pipeline or Distribution System | Basis for Valuation of the Initial Capital Base |
|---|---|---|
| ***Final Decisions*** | | |
| ACCC | Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd transmission systems (Victoria) (October 1998) | DORC value, adjusted downward by approximately 2.8 percent to avoid tariff increases. |
| ORG | Multinet, Westar and Stratus distribution systems (Victoria) (October 1998) | DORC value, adjusted downwards by between zero and 8 percent for different parts of the distribution systems in order to avoid tariff increases. |
| WA Gas Access Regulator | AlintaGas Mid-West and South-West Gas Distribution Systems (June 2000) | Value determined consistent with returning Reference tariffs and a Total Revenue equating to an *a priori* revenue forecast for the distribution systems. The value was approximately 75 percent of an estimated DORC. |
| WA Gas Access Regulator | Parmelia Pipeline (October 2000) | Value determined based on the economic value of the pipeline, impacts on tariffs and a balancing of interests between the Service Provider and Users, and subject to a Redundant Capital Policy that will see the value reduced if forecast market growth does not eventuate. The value is approximately 95 percent a DORC value estimated on the basis of a replacement asset with capacity equal to an assumed future throughput taking into account substantial under utilisation of existing assets. |

**Initial Capital Base determinations for gas transmission and distribution systems**

| Regulatory Agency | Pipeline or Distribution System | Basis for Valuation of the Initial Capital Base |
|---|---|---|
| IPART | Great Southern Energy Gas Networks Pty Limited (NSW) (September 1999) | Value determined between DAC and DORC values on the basis of impacts on tariffs and a balancing of interests between the Service Provider and Users. The value is approximately 82 percent of DORC and 188 percent of DAC. |
| IPART | Albury Gas Company Limited (December 1999) | DORC value, adjusted downwards by approximately 7 percent to avoid network price differentials. |
| ACCC | AGL Pipelines (NSW) Pty Ltd Central West Pipeline (June 2000) | DORC value (but nominally equivalent to a DAC value as this is a new pipeline – 12 months old at the time of valuation) |
| IPART | AGL Gas Network Limited Natural Gas System in NSW (July 2000) | Value determined at an approximate mid point between DAC and DORC values on the basis of a balance of interests between the Service Provider and Users providing for reasonable financial outcomes for the Service Provider and real reductions in tariffs. |
| ***Draft Decisions*** | | |
| WA Gas Access Regulator | Tubridgi Pipeline System (August 2000) | DORC value derived by applying depreciation to an Optimised Replacement Cost at a rate reflecting expected historical asset depreciation. |
| ACCC | Eastern Australian Pipelines Limited Moomba to Sydney Pipeline (December 2000) | DORC value, derived by applying depreciation to an Optimised Replacement Cost at a rate reflecting expected historical asset depreciation. |
| WA Gas Access Regulator | Goldfields Gas Pipeline (April 2001) | DAC value (but in excess of the DORC value). |

Regulatory decisions in Australia have most commonly derived Capital Base values through a methodology whereby initial DORC values are reduced in accordance with criteria based on a balancing of interests of the Service Provider and Users. For the most part, the criteria for a balance of interests have been that regulated tariffs should not exceed existing tariffs. Derivation of a Capital Base value from a DORC valuation has commonly been used due to the ability to derive disaggregated asset values from the DORC valuations of asset classes.

The Regulator does not consider there to be any established or generally accepted "international best practice" in asset valuation that could be applied to the DBNGP. However, the Regulator does accept that there is precedent for not valuing assets in excess of a DORC value, and for considering values less than DORC in relation to the particular context and history of the assets being valued, and the interests of the Service Provider and Users. Given this, the Regulator does not consider there to be any precedent for asset valuation for the DBNGP as proposed by Epic Energy, on the basis of cost of purchase that is well in excess of estimates of DORC values.

### 5.3.4.7 Historical Tariffs, Returns and Economic Depreciation

Paragraph 8.10(f) of the Code requires that 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.

The Regulator considered the basis upon which tariffs had been set in the past and historical returns of capital to the Service Provider in regard to a DAC valuation of the pipeline assets (page 120 of this Draft Decision).

Past tariffs for either gas sales to Alcoa of gas transmission for Alcoa and other third parties included capital charges determined by an annuity method, and which included a component of capital recovery. The Regulator derived a DAC value of $874.0 million on the basis of capital costs of the DBNGP assets and the estimated historical recovery of capital. The use of this value as the Initial Capital Base for the DBNGP would be have the advantages and disadvantages pertaining to a DAC value as outlined in section 5.3.4.5 of this Draft Decision).

#### 5.3.4.8 Reasonable Expectations under the Prior Regulatory Regime

Paragraph 8.10(g) of the Code requires that 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.

The Regulator has interpreted paragraph 8.10(g) of the Code as requiring that the Regulator consider 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 that applied to the DBNGP prior to the commencement of the Code was regulation under the *Gas Corporation Act 1994* and the subordinate *Gas Transmission Regulations 1994*, and the *Dampier to Bunbury Pipeline Act 1997* and the subordinate *Dampier to Bunbury Pipeline Regulations 1998*.

Regulated tariffs for third party Users of the DBNGP were enacted under each of the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998*. The methodology used to derive these tariffs was similar to the methodology established by section 8 of the Code.[174] That is, determination of a total revenue requirement by a building-block approach involving summing of a return on the value of an asset base, depreciation of the asset base and operating and maintenance costs, and then specification of a tariff schedule that would result in the return of this total revenue given throughput forecasts.

The asset value used for the determination of regulated tariffs was derived from set of regulatory accounts whereby an opening asset value was taken as a written down value of the assets as at 31 December 1994. The asset value was changed over time by addition of capital expenditure and subtraction of depreciation. Depreciation was determined by an annuity method whereby the initial asset value was to be fully depreciated over a 20 year period from 1 January 1995, and new facilities arising from capital investment subsequent to 1 January 1995 fully depreciated over assumed asset lives ranging between 10 and 30 years depending upon the nature of the new facility.

[174] Energy Implementation Group, November 1994, Dampier to Bunbury Natural Gas Pipeline Initial Charges for Gas Transportation; AlintaGas Transmission Business, December 1997, Dampier to Bunbury Natural Gas Pipeline: Price Redetermination Prepared in Accordance with Regulation 151 of the Gas Transmission Regulations 1994.

The regulatory regime existing prior to the commencement of the Code therefore 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 somewhat arbitrary value assigned to the assets on transfer from SECWA to the newly formed Gas Corporation. 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 Regulator has estimated this value from the book values of assets at the time of transfer of assets from the State Energy Commission of Western Australia to the Gas Corporation (AlintaGas), with subsequent additions of capital expenditure and subtraction of depreciation. The assumptions used in deriving a DAC value as at 31 December 1999 on this basis were as follows.

- Capital expenditure as undertaken by AlintaGas in the period 1995 to 1997, and Epic Energy in 1998 and 1999 as indicated below.

**DBNGP Capital Expenditure 1995 – 1999 ($million, year ending 31 December)**

| 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|
| 10.32 | 32.36 | 62.31 | 43.08 | 79.23 |

- For assets in existence at the start of 1995, estimation of depreciation by an annuity method with an asset amortisation period of 20 years and WACC of 13.03 percent for the period 1995 to 1997 and 11.12 percent for 1998 and 1999, in accordance with determination of tariffs under the Gas Transmission Regulations.[175]
- For assets constructed since 1995, depreciation by an annuity method with amortisation periods of between 3.3 and 30 years for different asset classes, and WACC of 13.03 percent for the period 1995 to 1997 and 11.12 percent for 1998 and 1999.

The asset value based on the book value of assets in 1995 and these assumptions as to capital expenditure and depreciation is $1,256.2 million, derived as follows.

[175] Energy Implementation Group, November 1994, Dampier to Bunbury Natural Gas Pipeline Initial Charges for Gas Transportation; AlintaGas Transmission Business, December 1997, Dampier to Bunbury Natural Gas Pipeline: Price Redetermination Prepared in Accordance with Regulation 151 of the Gas Transmission Regulations 1994.

**DBNGP DAC value at 31 December 1999 estimated from 1995 book values of assets ($million)**

| Year | 1995 | 1996 | 1997 | 1998 | 1999 |
|---|---|---|---|---|---|
| Opening asset value | 1,138.7 | 1,135.0 | 1,151.1 | 1,181.2[176] | 1,196.4 |
| Depreciation | 14.0 | 16.3 | 19.4 | 27.9 | 31.5 |
| Capital expenditure | 10.3 | 32.4 | 62.3 | 43.1 | 99.0[177] |
| Closing asset value | 1,135.0 | 1,151.1 | 1,194.0 | 1,196.4 | 1,263.8 |

In order to use the above DAC value basis for regulatory asset valuation it would be necessary to add a value for non-depreciable assets. Non-depreciable assets have been estimated to be in the order of $6.3 million giving a total asset value of $1,270.1 million. The use of this value as the Initial Capital Base for the DBNGP would have the advantages and disadvantages pertaining to a DAC value as outlined in section 5.3.4.5 of this Draft Decision.

### 5.3.4.9 Economically Efficient Utilisation of Gas Resources

Paragraph 8.10(h) of the Code requires that consideration be given to:

> The impact on the economically efficient utilisation of gas resources.

This section of the Code requires the Regulator to consider the effect of asset valuation methodologies on the use of gas resources and in particular on whether the valuation methodology is consistent with tariffs that will provide the price signals that are consistent with economic efficiency in the use of these resources. The Victorian Office of the Regulator General has interpreted this requirement 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.[178]

Efficient use of gas vis a vis other energy resources would require that Users of the DBNGP, and ultimately the end users of gas, should pay at least the avoidable cost of gas transportation, which is the (forward-looking) cost that the Service Provider could avoid by ceasing to provide the transportation service. This avoidable cost would not, however, include capital costs arising from sunk investment. Consequently, in order to motivate the efficient use of gas, the valuation of the Capital Base and the allocation of resultant capital costs should be designed to minimise the divergence in gas usage from the efficient levels that would occur if Users paid only the avoidable cost.

This criterion would generally require that the valuation of the Capital Base be as low as possible while still being consistent with providing the signals to investors in gas distribution

[176] Note that the estimated value of the East Perth Lateral, the Geraldton Lateral and the Clifton Road to Bunbury Extension has been subtracted from the 1997 closing asset value, as these assets were not sold with the pipeline.

[177] 1999 capital expenditure includes all expenditure on the stage 3A pipeline expansion.

[178] 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.

assets that motivate a longer-term efficient level of investment in gas transmission assets. 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 at an inflation adjusted capital cost or inflation adjusted historic cost. A DORC value might also meet this criterion.

#### 5.3.4.10 Comparability with Cost Structures of New Pipelines

Paragraph 8.10(i) of the Code requires that consideration be given to:

> 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).

The Initial Capital Base should not be so high as to result in Reference Tariffs that motivate inefficient provision of transmission assets. This may occur though high tariffs motivating investment in assets by other Service Providers that results in the total capital costs of transmission assets (including the existing assets) being greater than the minimum or efficient capital costs necessary to provide the transmission services. Inefficient investment may generally be regarded as occurring where there is duplication of the existing assets or by-passing of the existing assets by service from an alternative transmission system at a time when there is still significant excess capacity in the existing assets.

In principle, an upper bound on the Initial Capital Base of a "new entrant" DORC value is consistent with not creating any incentive for duplication of the existing assets as it can be argued that only values in excess of DORC would imply the earning of monopoly profits by the Service Provider. In practice, however, Capital Base values well in excess of DORC could potentially be established without motivating inefficient duplication of assets. Reasons for this are 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 market share.[179]

A further matter to consider in regard to incentives for duplication of assets is that if faced by a genuine prospect of by-pass and competition, an existing Service Provider would, regardless of the existence of regulated tariffs, have an incentive to reduce tariffs to discourage competition. In principle, given that capital costs are sunk costs, a Service Provider would have an incentive to reduce tariffs to the extent necessary to discourage competition as long as the tariffs were still sufficient to cover the avoidable costs of service provision.

In view of the above, the Regulator does considers that comparability of an asset value with asset costs incurred, or potentially incurred by competing pipeline Service Providers is not a matter of material importance in considering valuation of the Initial Capital Base of the DBNGP.

#### 5.3.4.11 Price Paid for Assets by the Service Provider

Paragraph 8.10(j) of the Code requires that consideration be given to:

> The price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase.

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[179] 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).

Epic Energy has proposed an Initial Capital Base for the DBNGP assets of $2,570.34 million as at 31 December 1999, being the cost to Epic Energy of purchase of these assets as at 25 March 1998, with adjustment to account for depreciation and capital expenditure in the period from 25 March 1998 to 31 December 2000.

The use of the cost of purchase as a basis for valuation of the Initial Capital Base has been discussed above (refer to pages 136 and 144). The Regulator has concluded that it is difficult to determine the merit of valuation of the DBNGP at a purchase price as this price may have been affected by many factors other than a reasonable market value of the assets that is consistent with future regulated revenues and efficient capital investment. Epic Energy has not demonstrated to the satisfaction of the Regulator that the purchase price of the assets represented a reasonable valuation by any conventional valuation methodology.

Epic Energy's argument for valuation of the Initial Capital Base is not based on considerations other than, or at least in addition to, the reasonableness or otherwise of the price paid by Epic Energy. Rather, Epic Energy has argued that valuation at the cost of purchase is justified by the circumstances of the purchase, in particular the following.

- It is inappropriate to constrain the value the Initial Capital Base to values within the range established by paragraphs 8.10(a) (DAC) and 8.10(b) (DORC) of the Code because of:
  - the process by which the DBNGP was sold, by which the Western Australian Government accepted Epic Energy's bid at least in part on the basis of an indication by Epic Energy of a set of tariffs that Epic Energy intended to apply subsequent to the pipeline sale, and that these tariffs would provide Epic Energy with an acceptable return on its investment; and
  - the existing regulatory arrangements for the DBNGP which potentially enables existing third party Users of the pipeline to elect to pay a tariff equal to or derived from the Reference Tariff established as part of the Access Arrangement.
- Setting the Initial Capital Base at less than the cost of purchase incurred by Epic Energy would expose Epic Energy to a risk of not being able to recoup the price paid for the DBNGP.

In considering the arguments put forward by Epic Energy, the Regulator considered the circumstances of the DBNGP sale and the views that prospective purchasers of the DBNGP could reasonably have arrived at in respect of the regulatory asset value likely to be established under the Code.

The Information Memorandum provided to prospective purchasers of the DBNGP in 1997 as part of the sale process provided information on future regulation of the DBNGP. Specifically, it was indicated that the Western Australian Government intended to adopt a new regulatory framework as of 1 January 2000 consistent with the Code that was then being developed by the Commonwealth and State and Territory Governments.[180] The Information Memorandum indicated to prospective purchasers that the Code would require the owner of the DBNGP to develop an Access Arrangement that sets out, amongst other things, Reference Tariffs calculated in accordance with detailed principles relating to matters including asset valuation, apportionment of costs, depreciation and incentive mechanisms.[181] Prospective purchasers were therefore informed that, subsequent to the DBNGP sale, the assets of the

[180] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 95.
[181] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 106.

DBNGP would be valued for regulatory purposes in accordance with principles set out in the proposed Code.

The Information Memorandum indicated that the Gas Pipeline Sale Steering Committee commissioned an "independent, indicative valuation" for the DBNGP assets, consistent with the principles of the Code. This valuation was commissioned by the Committee for the purpose of its own considerations of future tariff paths for the services provided by the DBNGP.[182] This valuation exercise was described in the Information Memorandum:[183]

> The Indicative Valuation suggests that a supportable Capital Base for the DBNGP Assets, being an Optimised Depreciated Replacement Cost ("ODRC") [sic [184]] base consistent with the [National Access Code] 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 [National Access Code], followed consideration of Depreciated Historical Cost ("DHC") data.

In the view of the Regulator, the Government can be regarded as having put forward the view in the Information Memorandum that it expected the valuation of the DBNGP assets to be determined in accordance with a DORC valuation methodology, even though consideration may be given to depreciated historical cost. Furthermore, despite an indication in the Information Memorandum that the Gas Pipeline Sale Steering Committee "makes no representation that the indicative valuation … would have any standing, weight or force in respect of the considerations of, or would be approved by, a Regulator",[185] the Regulator considers that it would have been reasonable for a prospective purchaser to attribute some likelihood to a DORC valuation of the DBNGP assets. The Regulator also notes in this regard that at the time prospective purchasers would have considered the Information Memorandum and placed final bids for the DBNGP, that no regulatory decision had been made as to a valuation of gas pipeline assets under the Code, and hence there was no valuation precedent upon which prospective purchasers could have formed expectations of asset valuations under the Code.

The Information Memorandum also indicated that the Gas Pipeline Sale Steering Committee 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, also subject to the qualification that the Committee makes no representation that the indicated tariff "would have any standing, weight or force in respect of the considerations of, or would be approved by, a Regulator".[186] The Information Memorandum indicated that it is the Government's expectation that the full-haul, 100 percent load factor tariff would be of the order of $1.00/GJ at 1 January 2000.[187] No indication was made of Government expectations of the tariff subsequent to 1 January 2000.

The Regulator considers that under the circumstances of the sale of the DBNGP, as evidenced in the Information Memorandum, that a prospective purchaser of the DBNGP could reasonably have developed an expectation of a full-haul, 100 percent load factor tariff of $1.00/GJ at 1 January 2000 and tariffs subsequent to that date determined consistent with a DORC-based valuation of the DBNGP assets. Notwithstanding such an expectation, a

[182] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 106.

[183] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, pp 106, 107.

[184] Equivalent to a DORC value.

[185] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 108.

[186] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 108.

[187] Dampier to Bunbury Natural Gas Pipeline Information Memorandum, p 107.

purchaser may have considered it appropriate to offer a purchase price different to the expected regulatory valuation of the assets under the Code based on the purchaser's own considerations as to the value of ownership of the DBNGP. The Regulator considers, however, that regardless of the purchase price paid by the successful bidder for the DBNGP assets, the circumstances of the DBNGP sale do not provide a basis for a prospective purchaser to reasonably expect a regulatory asset value under the Code in excess of a DORC value.

#### 5.3.4.12 Other Relevant Factors

Paragraph 8.10(k) of the Code requires that consideration be given to:

> Any other factors the Relevant Regulator considers relevant.

In making a determination on the Initial Capital Base for the DBNGP, the Regulator considered factors set out in paragraphs 8.10(a) to 8.10(j) of the Code, taking into account relevant public submissions as discussed in section 5.3.3 of this Draft Decision. The Regulator did not give consideration to any other factors.

#### 5.3.4.13 Conclusion and Initial Capital Base

In making a determination on an appropriate value of the Initial Capital Base for the DBNGP, the Regulator has given consideration to the guidelines provided by sections 8.10 and 8.11 of the Code, and to the specific circumstances of the DBNGP

The Regulator does not consider there to be any 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, the Regulator does not consider there to be any reason to value the Initial Capital Base in excess of a DORC value. The Regulator's reasons for this position are the economic arguments for the Initial Capital Base to not be in excess of the DORC value, and also that the sale process for the DBNGP, as evidenced by the Information Memorandum, would have led to the reasonable expectation that the asset valuation for the DBNGP under the Code would not be in excess of a DORC value.

In considering possible values for the DBNGP, the Regulator noted that the Information Memorandum gave particular attention to a DORC valuation of the DBNGP in providing an indication of the tariffs that may apply under the Code. It is the Regulator's view that, despite disclaimers in the Information Memorandum that no representation was being made as to the likely values of the Initial Capital Base or tariffs under the Code, this may have led to reasonable expectations of such a valuation under the Code being likely. It is noted that at the time of the sale of the DBNGP, there were no precedents for valuation of assets under the Code. Given this, the Regulator determined that a reasonable value of the Initial Capital Base for the DBNGP is a DORC value of $1,233.66 million as at 31 December 1999, based on an Optimised Replacement Cost Valuation underlying the DORC valuation presented in the Information Memorandum, and taking into account inflation, capital expenditure[188] and depreciation in the period to 31 December 1999.

The Regulator notes that the Initial Capital Base value of $1,233.66 million is close to the DORC value submitted by Epic Energy after adjustment by the Regulator ($1,227.4 million,

[188] Capital expenditure includes all expenditure for the Stage 3A enhancement, even though Epic Energy considered some of this expenditure to occur in 2000. Refer to section 5.4.4 of this Draft Decision for a discussion of the Regulator's considerations in respect of Epic Energy's forecast Capital Expenditure.

section 5.3.4.3 of this Draft Decision) and the value that might have been applied to the determination of third-party tariffs if the previous regulatory regime had continued ($1,270.1 million, section 5.3.4.8 of this Draft Decision).

For the purposes of assessing the Reference Tariff proposed by Epic Energy, the Regulator has contemplated an allocation of this asset value across asset classes in the same manner and proportions as proposed by Epic Energy. The Regulator's revised allocation of asset value across assets is as follows.

**Revised Initial Capital Base by asset class**

| **Asset** | **Asset Value at 31 December 1999 ($ million)** |
|---|---|
| Pipeline assets | |
| Zone 1a | 15.84 |
| Zone 1b | 143.52 |
| Zone 2 | 77.59 |
| Zone 3 | 77.85 |
| Zone 4 | 78.05 |
| Zone 4a | 32.20 |
| Zone 5 | 79.28 |
| Zone 6 | 80.14 |
| Zone 7 | 90.40 |
| Zone 8 | 80.77 |
| Zone 9 | 109.44 |
| Zone 10 | 138.56 |
| Compression assets | |
| Compressor station 1 | 11.59 |
| Compressor station 2 | 12.57 |
| Compressor station 3 | 21.42 |
| Compressor station 4 | 12.20 |
| Compressor station 5 | 21.65 |
| Compressor station 6 | 23.83 |
| Compressor station 7 | 11.73 |
| Compressor station 8 | 22.09 |
| Compressor station 9 | 24.40 |
| Compressor station 10 | 6.64 |
| Metering assets | 13.79 |
| Other assets | |
| Depreciable | 37.87 |
| Non-depreciable (land and pipeline linepack) | 10.24 |
| **Total** | **1,233.66** |

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 52

The proposed Access Arrangement and Access Arrangement Information should be amended to reflect an Initial Capital Base of $1,233.66 million as at 31 December 1999.

## 5.4 CAPITAL EXPENDITURE

### 5.4.1 Access Code Requirements

Sections 8.15 to 8.21 of the Code provide for forecast Capital Expenditure on a Covered Pipeline and associated regulated assets to be incorporated into the Capital Base of the pipeline, and for forecast Capital Expenditure to be considered in determination of Reference Tariffs.

The Capital Base of a Covered Pipeline may be increased from the commencement of a new proposed Access Arrangement Period to recognise capital costs incurred in constructing New Facilities for the purpose of providing services, subject to the New Facilities Investment meeting certain criteria.

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

(b) one of the following conditions is satisfied –

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

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

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

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.

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 come to be met. Section 8.19 also sets out the manner in which the value of the Speculative Investment Fund is determined at any time.

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, if asked to do so by the Service Provider, at the time at which the investment takes place.

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 whether (and how) the Capital Base at the commencement of the next Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment.

Sections 8.23 to 8.25 of the Code set out provisions for New Facilities Investment to be financed in whole or in part of capital contributions from Users, or from surcharges over and above Reference Tariffs to be levied on Users.

### 5.4.2 Access Arrangement Proposal

Epic Energy provided details of planned Capital Expenditure 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 (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 |

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

| Type of Investment | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| 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** |

### 5.4.3 Submissions from Interested Parties

#### 5.4.3.1 Scope of Submissions

Submissions on the proposed Access Arrangement had limited comment in relation to Epic Energy's forecast Capital Expenditure, being limited to requesting that the Regulator assess the efficiency and prudence of Capital Expenditure, and specific comment on proposed expenditure for development of a customer reporting system. Submissions on these matters and responses from the Regulator are detailed below.

### 5.4.3.2 Assessment of Forecast Capital Expenditure

- WMC

  WMC has no particular comment to make on this issue, except to repeat earlier comments that the Initial Capital Base (both DORC and DAC basis), future capital expenditures and future operations and maintenance expenditures should be carefully reviewed in detail by competent independent and expert consultants and allowed only to the extent that they are at efficient (best practice) expenditure levels and matched to the reasonably expected levels of throughput during the Access Period.

- Western Power Submission 3

  As noted there is little by way of justification for the planned capital expenditure. This is required under the conditions of Prior Contracts.

- Western Power Submission 5

  The requirement for the Forecast Capital Works Expenditure is not adequately explained in Epic Energy's Access Arrangement in accordance with the Code.

- CMS Gas Transmission

  Section 3 of the Access Arrangement Information provides an inordinate level of detail for the future capital expenditure projected.

  The level of detail which Epic have provided in regard to future capital costs appears designed to obfuscate the inclusion of costs which may not be specific to the operation of the DBNGP.

- Robe River Mining

  We request that the Regulator verify the projected capital expenditures in the context of the assumed and expected likely expansion of the DBNGP market and be satisfied with the reasonableness of the projections.

The Regulator assessed Epic Energy's forecast Capital Expenditure against the requirements of sections 8.20 and 8.21 of the Code. That is, assessed 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. In undertaking the assessment, the Regulator obtained technical advice from engineering consultants Connell Wagner Pty Ltd. The Regulator's deliberations and conclusions on the forecast Capital Expenditure are set out in section 5.4.4 of this Draft Decision.

The Regulator is of the view that the level of detail provided in the Access Arrangement Information on the forecast Capital Expenditure is appropriate. Assessment of forecast Capital Expenditure against the requirements of section 8.16 of the Code requires that the forecast expenditure be examined on a project-by-project basis. In undertaking the assessment, the Regulator has in some instances sought additional information from Epic Energy on the justification for individual projects.

### 5.4.3.3 Capital Expenditure and Non-Capital Costs

- AlintaGas Submission 3

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

In assessing the proposed Capital Expenditure, the Regulator took into account the comment from AlintaGas that some items of forecast expenditure may more appropriately be regarded as Non-Capital Costs. As indicated in the Regulator's detailed discussion of Capital Expenditure (section 5.4.4, below), the Regulator concluded that amounts indicated for the cost classifications of flood damage mitigation, GEAs upgrade, tools and equipment and inventory management should be incorporated in Non-Capital Costs for the respective years of the Access Arrangement Period.

#### 5.4.3.4 Expenditure on the Customer Reporting System

- Western Power Submission 5

  The proposed Access arrangement is not clear as to whether the customer reporting system costs apply solely to the DBNGP, and are separate for customer reporting system costs for operating other Epic Energy pipeline systems in South Australia, Queensland and the Dampier to Port Hedland Pipeline, which may be recovered in other Access Arrangements.

  Western Power asks the Regulator to ensure that Epic Energy correctly apportions customer reporting system costs between its separate pipeline businesses in so far as the Access Arrangement for the DBNGP is concerned.

- CMS Gas Transmission

  CMS would question whether investment in the customer reporting system (for example) might not be a cost that should be shared across Epic's interstate operations.

The Regulator's assessment of the proposed expenditure on the customer reporting system is summarised in section 5.4.4 of this Draft Decision. In considering the proposed expenditure, the Regulator noted that expenditure on the customer reporting system has been poorly justified. The Regulator will accept the proposed Capital Expenditure for the purposes of this Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

### 5.4.4 Additional Considerations of the Regulator

#### 5.4.4.1 Scope of Cost Assessment

The Regulator considered the forecast Capital Expenditure in terms of whether or not particular items of New Facilities Investment could reasonably be expected to pass the tests of section 8.16 of the Code. The Regulator obtained technical advice from Connell Wagner in this respect. The Regulator's deliberations in this regard are described as follows for items of expenditure as described by Epic Energy in section 3.7 of the Access Arrangement Information.

#### 5.4.4.2 Pipeline Facilities

**Flood Damage Mitigation**

Epic Energy has forecast capital expenditure on flood damage mitigation as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Flood damage mitigation | 0 | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |

The justification provided for this expenditure is that enhancement of river banks is required on an "ongoing" basis where there is a susceptibility to erosion. While Epic Energy has indicated that the expenditure includes provision for installation of revetment control banks at critical river banks and sections of the pipeline, no indication of the proportion of expenditure that is attributable to such "one off" works was provided.

The Regulator considers that the ongoing nature of the flood damage mitigation works is reason to consider the cost of such works as a Non-Capital Cost and requires that the cost forecasts and tariff calculations of the proposed Access Arrangement and Access Arrangement Information be amended accordingly.[189]

### Pipeline Protection

Epic Energy has forecast capital expenditure on pipeline protection as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Pipeline protection | 0 | 0.20 | 0 | 0.20 | 0 | 0.40 |

The justification provided for this expenditure is that land development near the pipeline necessitates additional protection of the pipeline, involving protection of the pipeline by concrete slabs. Technical advice received by the Regulator indicated that the Department of Resources Development has commissioned a study to define a safe barrier around high pressure pipelines in the metropolitan area and the measures required to protection pipelines.

In the absence of information on required and proposed works, the Regulator is unable to form a view on the reasonableness of the proposed expenditure. However, the Regulator considers that works of the type contemplated by Epic Energy may be required for reasons of public safety and therefore could reasonably be expected to pass the tests of section 8.16 of the Code.

### Mainline Valves and Repeater Sites

Epic Energy has forecast capital expenditure associated with mainline valve and repeater sites as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Mainline valve CCVT upgrade | 0 | 0 | 0.08 | 0.08 | 0.08 | 0.24 |
| Mainline valve GEA upgrades | 0 | 0.04 | 0.04 | 0.04 | 0 | 0.12 |
| Mainline valve and repeater earthing | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.15 |

The justification provided for expenditure on upgrades of closed circuit vapour turbines (CCVTs) is that control systems installed in 1984 and 1985 require replacement. On the basis of technical advice, the Regulator considers this expenditure to be reasonable and likely to pass the tests of section 8.16 of the Code.

[189] Refer to section 5.4.4.6 and Amendment 53 of this Draft Decision, relating to aggregate changes to forecasts of Capital Expenditure used for the purposes of determining the Reference Tariff.

The justification provided for expenditure on the 10 KW Gas Engine Alternators (GEAs) is that oil seals require replacement at a cost of $5,000 per unit. On the basis of technical advice, the Regulator considers the expenditure to be justified, but to be in the nature of a Non-Capital Cost. The Regulator therefore requires that the cost forecasts and tariff calculations of the proposed Access Arrangement and Access Arrangement Information be amended accordingly.[190]

The justification for expenditure on the mainline valve and repeater station earthing systems is that the earthing systems are installed for protection of equipment and personnel and that deteriorated or corroded earthing systems require replacement after 15 years life, at a cost of $15,000 per site. On the basis of technical advice and considerations of operating safety, the Regulator considers this expenditure to be reasonable and likely to pass the tests of section 8.16 of the Code.

### WLPG Heat Exchanger Project

Epic Energy forecast capital expenditure for installation of a gas to gas heat exchanger at the inlet to the Wesfarmers LPG plant as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| WLPG heat exchanger | 0.40 | 0 | 0 | 0 | 0 | 0.40 |

Epic Energy's justification for the expenditure is ambiguous, indicating that:

> The WLPG contract as prepared by AlintaGas required for the gas entry into the WLPG plant to be at no less that 10 degrees and no more than 40 degrees.
>
> With the commissioning and operation of CS9 and the higher temperatures experienced into the plant, lower temperatures are being experienced into the plant and for 4 to 5 months of the year, gas is being delivered into the plant at lower than 10 degrees.

Technical advice to the Regulator was that the need for the investment may arise from a higher inlet pressure to the WLPG plant subsequent to the commissioning of CS9, and the larger pressure reduction at the inlet to the plant results in a lowering of the inlet gas temperature below the contractual limit. However, there may be alternative means of addressing the problem through pipeline operational practices. The Regulator does not consider that there is sufficient information to determine that the expenditure could reasonably be expected to pass the tests of section 8.16 of the Code. Notwithstanding this, the Regulator accepts the argument that the relevant problem may need to be addressed and therefore accepts the forecast Capital Expenditure for the purposes of the Draft Decision, although noting that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

[190] Refer to section 5.4.4.6 and Amendment 53 of this Draft Decision, relating to aggregate changes to forecasts of Capital Expenditure used for the purposes of determining the Reference Tariff.

#### 5.4.4.3 Compression Facilities

**Turbine/Compressor Upgrades (Stage 3A Enhancement)**

Epic Energy forecast capital expenditure for works associated with the turbine/compressor upgrades of the DBNGP as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Turbine/compressor upgrades | 20.19 | 1.30 | 1.40 | 0 | 0 | 22.89 |

Epic Energy has indicated that some of this expenditure is for final components of the Stage 3A enhancement that was commenced in 1998:

- construction and commissioning of compressors at CS2 and CS7 at a cost of $18.855 million; and
- final payments for CS10 at a cost of $632,000.

Additional turbine/compressor upgrades and associated capital expenditure included:

- “uprating” of compressor units at CS5/1 and CS5/2 at a cost of $1.4 million;
- completion of “warranty related work and as builts” at a cost of $250,000;
- “uprating” of compressor units at CS1 and CS8/1 at a cost of $1.4 million; and
- control view upgrade and condition monitoring equipment $350,000.

The Regulator notes that Epic Energy embarked on the Stage 3A enhancement in response to requests for additional capacity, and that Epic Energy is placed under an obligation to provide such additional capacity by section 5 of schedule 1 of the *Dampier to Bunbury Pipeline Act 1997*. As such, the Regulator accepts for the purposes of this Draft Decision that the forecast Capital Expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

Notwithstanding the reasonable expectation that expenditure for the Stage 3A enhancement would pass the tests of section 8.16 of the Code, the Regulator has decided to incorporate the cost of construction and commissioning of compressors at CS2 and CS7 of $19.487 million into the valuation of the Initial Capital Base as at 31 December 1999, as described in section 5.3.4 of this Draft Decision. This stance was taken in recognition of the bulk of the works associated with the forecast 2000 expenditure actually having been undertaken in 1999, and hence inclusion of this expenditure in the Initial Capital Base being consistent with the capacity of the DBNGP at the time of valuation.

The Regulator will therefore require the forecast Capital Expenditure to be revised in accordance with the following costs for the turbine/compressor upgrades (31 December 1999 dollar values).[191]

[191] Refer to section 5.4.4.6 and Amendment 53 of this Draft Decision, relating to aggregate changes to forecasts of Capital Expenditure used for the purposes of determining the Reference Tariff.

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Turbine/compressor upgrades | 0.70 | 1.30 | 1.40 | 0 | 0 | 3.40 |

**UPS Upgrade**

Epic Energy has forecast capital expenditure for upgrade of compressor station UPS systems as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| UPS upgrade | 0 | 0.15 | 0.15 | 0.15 | 0.15 | 0.60 |

Epic Energy has indicated that this expenditure is necessary for replacement of battery banks at compressor stations that are part of the power supply system for instrumentation and control systems.

On the basis of technical advice, the Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

**Airstrip Upgrade**

Epic Energy has forecast capital expenditure for upgrading airstrips at compressor stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Airstrip upgrade | 0.15 | 0.20 | 0.20 | | | 0.55 |

Epic Energy has indicated that this expenditure is necessary for the upgrading of airstrips at CS2 and CS5 to all-weather strips and modifications to helipads, in order to facilitate compressor maintenance and improve compressor performance.

On the basis of technical advice, the Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

**Water Treatment Plants**

Epic Energy has forecast capital expenditure for upgrading of water supplies at compressor stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Water treatment plants | 0 | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |

Epic Energy has indicated that this expenditure is necessary for the construction of replacement groundwater bores at four compressor stations.

On the basis of technical advice, the Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

### Air Conditioning Units

Epic Energy has forecast capital expenditure for upgrading of air conditioning units at compressor stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Air conditioning units | 0 | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |

Epic Energy has indicated that this expenditure is necessary for replacement of air conditioning systems as they reach 10 years of age.

On the basis of technical advice, the Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

### Compressor Station Facilities

Epic Energy has forecast capital expenditure for additional employee facilities at compressor stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Compressor Station Facilities | 0.11 | 0.05 | 0 | 0 | 0 | 0.16 |

Epic Energy has indicated that this expenditure is necessary for provision of computer facilities ($110,000) and recreation and training facilities ($50,000) (real 31 December 1999 values).

The Regulator notes that provision has been made elsewhere in the capital expenditure forecasts for computing facilities and software at remote work stations, and that there may be double counting by making provision for similar expenditure as part of compressor station facilities. While the Regulator accepts the forecast Capital Expenditure for the purposes of the Draft Decision, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

The Regulator is satisfied that the remaining forecast expenditure for recreation and training facilities is reasonable and likely to pass the tests of section 8.16 of the Code.

### Station MMI Upgrades

Epic Energy has forecast capital expenditure for man-machine interface (MMI) facilities at compressor stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Station MMI upgrades | 0 | 0.03 | 0.10 | 0.08 | 0.10 | 0.31 |

Epic Energy has indicated that this expenditure is necessary for replacement of hardware and software of existing MMIs.

On the basis of technical advice, the Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

**Installation of Flares for Control of Vented Odorised Gas**

Epic Energy has forecast the following capital expenditure associated with installation of flares for venting of odorised gas (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Portable flares | 0 | 0.02 | 0 | 0 | 0 | 0.02 |

The justification provided for expenditure on noise control is that residential and industrial urban development has encroached upon the pipeline easement, necessitating the cessation of venting of gas for avoidance of public nuisance. The Regulator is satisfied that such measures are a standard industry practice and justified in the circumstances.

The Regulator considers this expenditure to be reasonable and likely to pass the tests of section 8.16 of the Code.

**Sulphur Deposition Mitigation Programme**

Epic Energy has forecast capital expenditure associated with sulphur deposition mitigation as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Sulphur deposition mitigation | 0 | 1.00 | 1.00 | 0 | 0 | 2.00 |

The justification provided for expenditure on sulphur deposition mitigation is a potential reduction in outages and maintenance requirements. However, Epic Energy has indicated that the expenditure was to be subject to a feasibility study in 2000. The Regulator has not been provided with the results of this study. Furthermore, the Regulator considers that there may be other options to address the problem of sulphur deposition.

The Regulator accepts the forecast Capital Expenditure for the purposes of the Draft Decision. However, given the absence of results of the feasibility study, the Regulator notes that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

**NOx/SOx Emission Control for Gas Turbines**

Epic Energy has forecast the following capital expenditure for installation of NOx and SOx emission control equipment at compressor stations (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Greenhouse NOx/SOx control | 0 | 1.50 | 1.50 | 1.50 | 1.50 | 6.00 |

No justification for this expenditure has been provided other than it being necessary to retrofit the equipment at compressor stations north of CS9 as part of Epic Energy's commitment to the environment.

The Regulator is of the view that this expenditure could reasonably be regarded as being necessary for the safe provision of services. As such, the Regulator accepts that this expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

#### 5.4.4.4 Metering Facilities

**Noise Control**

Epic Energy has forecast capital expenditure associated with noise control at metering stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Noise control | 0 | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |

The justification provided for expenditure on noise control is that residential and industrial urban development has encroached upon the pipeline easement, necessitating noise control works at four metering stations: Harrow Road, Welshpool, Forestdale and Russell Road.

The Regulator considers this expenditure to be reasonable and likely to pass the tests of section 8.16 of the Code.

#### 5.4.4.5 Other Capital Expenditure

**Microwave System Upgrade**

Epic Energy has forecast capital expenditure associated with upgrading of the microwave communication system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Microwave system upgrade | 0.25 | 3.80 | 4.70 | 3.80 | 0 | 12.55 |

The justification provided for expenditure on upgrading of the microwave system is that it is a relatively old (greater than 14 years) analogue system and replacement with a digital system would lead to lower maintenance costs and improved capability. The forecast expenditure includes provision for a feasibility study in 2000 and upgrade costs in 2001 to 2003.

On the basis of technical advice, the Regulator is of the view that upgrading of the microwave system has not been demonstrated by Epic Energy to be the most cost effective communication system – a satellite communication system could be of lower initial cost and have lower maintenance costs. The Regulator accepts that upgrading of communication systems may be necessary and will accept the proposed Capital Expenditure for the purposes of this Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

**VHF Communications Upgrade**

Epic Energy has forecast capital expenditure associated with upgrading of the VHF communication system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| VHF communications upgrade | 0 | 0.20 | 0.25 | 0.20 | 0 | 0.65 |

The justification provided for expenditure on upgrading of the VHF communications system is desirable to improve the functionality of the existing system, reduce reliance on satellite phones and reduce operating costs. Provision for a feasibility study was included in the forecast expenditure for upgrading of the microwave communications system. Upgrade costs are forecast to be incurred in 2001 to 2003.

Epic Energy did not provide details of expected cost savings from the VHF communications upgrade, and these may not have been estimated in advance of the feasibility study. However, on the basis of technical advice, the Regulator is of the view that upgrading of the VHF communications system could reasonably be expected to provide benefits through improved safety for staff in remote areas and improved efficiency in performing of tasks in remote areas. As such, the Regulator is satisfied that forecast expenditure is reasonably likely to meet the requirements of section 8.16(a) of the Code.

**Replacement of Remote Terminal Units (SCADA Upgrade)**

Epic Energy has forecast capital expenditure associated with replacement of remote terminal units as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| SCADA upgrade | 0 | 0.30 | 0.25 | 0.20 | 0 | 0.75 |

The justification provided for expenditure on replacement of the remote terminal units is a reduction in operating and maintenance costs by replacing technically redundant remote terminal units with new equipment.

The Regulator has noted an inconsistency between the justification for this item of capital expenditure and Epic Energy's Maintenance Branch's *2000 Annual Program* that states:

> Individual SCADA RTUs and the MLV sites are generally very reliable, with target individual availability of 99.9%. Hence minimal maintenance is performed on the units.

Similar statements about reliability of RTU's were made in the 2000 Annual Program for the remote terminal units at compressor and metering stations.

The Regulator is of the view that replacement of the remote terminal units has been poorly justified. The Regulator will accept the proposed Capital Expenditure for the purposes of this

Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

### Customer Reporting System

Epic Energy has forecast capital expenditure associated with development of a customer reporting system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Customer reporting system | 2.40 | 0 | 0 | 0 | 0 | 2.40 |

The justification provided for expenditure on the customer reporting system is that the system is necessary for the reporting of information in relation to the transportation services of the DBNGP, and to provide an electronic bulletin board for Shippers to interact with Epic Energy.

The Regulator is of the view that a bulletin board interface between Epic Energy and Shippers is arguably necessary for the operation of the pipeline, and indeed expenditure on such a system may be necessary to meet the Regulator's requirements to provide information to Shippers on their use of pipeline services and potential liability to penalties (Amendment 5). The Regulator notes that an electronic bulletin board already exists and is being used by Users. The Regulator also notes the concerns expressed in submissions in regard to the proposed expenditure on the customer reporting system and the potential for sharing the capital costs of such a system with other pipeline operations of Epic Energy.

The Regulator is of the view that expenditure on the customer reporting system has been poorly justified. The Regulator will accept the proposed Capital Expenditure for the purposes of this Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

### Computer System Upgrades

Epic Energy has forecast capital expenditure associated with computer system upgrades as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Computer system upgrades | 0.62 | 0.15 | 0.15 | 0.15 | 0.15 | 1.22 |

The justification provided for expenditure on computer system upgrades is that the following measures are necessary to maintain the level of support dictated by the business:

- upgrading of network software at a cost of $20,000;
- upgrading of remote distribution software at a cost of $50,000;
- replacement of work station hardware and personal computers at an initial cost of $300,000 in 2000 and subsequent annual cost of $150,000;
- integration of Epic Energy's computerised maintenance management system with the financial system at a cost of $100,000; and

- upgrading of the financial management system at a cost of $150,000.

On the basis of technical advice, the Regulator considers that the costs for upgrading of work station hardware and personal computers, integration of Epic Energy's computerised maintenance management system with the financial system and upgrading of the financial management system have been poorly justified. The Regulator will accept the proposed Capital Expenditure for the purposes of this Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

**Information Management System**

Epic Energy has forecast capital expenditure associated with establishing an information management system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Information management system | 0.50 | 0 | 0 | 0 | 0 | 0.50 |

No justification or details of costs have been provided for expenditure on the information management system. The Regulator will accept the proposed Capital Expenditure for the purposes of this Draft Decision. However, it is noted that more rigorous justification would need to be provided before actual expenditure on this item would be added to the Capital Base.

**SCADA Master Station Protocols**

Epic Energy has forecast capital expenditure associated with establishing different protocols and suitable hardware for SCADA master stations as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| SCADA master station protocols | 0 | 0.08 | 0 | 0 | 0 | 0.08 |

No justification or details of costs have been provided for expenditure on the SCADA master station protocols. However, the Regulator acknowledges that expenditure for such items may reasonably be regarded as necessary and the value of the expenditure is small. On this basis, the Regulator concludes that the forecast expenditure for the SCADA master station protocols is reasonably likely to meet the requirements of section 8.16 of the Code.

**SCADA Master Station Backup System, CS6 and CS9 Visibility**

Epic Energy has forecast capital expenditure associated with upgrading the SCADA master station backup system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| SCADA master station CS6, 9 visibility | 0.10 | 0 | 0 | 0 | 0 | 0.10 |

Justification for the expenditure is that it is necessary to replace temporary equipment with permanent equipment, in accordance with the original design intent for the stage two expansion of the DBNGP and to provide better communications "visibility" with compressor stations 6 and 9. The Regulator acknowledges that expenditure for such items may reasonably be regarded as necessary and the value of the expenditure is small. On this basis, the Regulator concludes that the forecast expenditure for the SCADA master station backup system is reasonably likely to meet the requirements of section 8.16 of the Code.

**Motor Vehicles**

Epic Energy has forecast capital expenditure associated with purchase of motor vehicles as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Motor vehicles | 0 | 0.25 | 0.25 | 0.25 | 0.25 | 1.00 |

Justification for the expenditure is that it is necessary to replace six motor vehicles per annum from 2001 onwards at a total cost of $250,000 per annum. The Regulator notes that this is a relatively modest programme for vehicle replacement. On this basis, the Regulator concludes that the forecast expenditure for the motor vehicles is reasonably likely to meet the requirements of section 8.16 of the Code.

**Tools and Equipment**

Epic Energy has forecast capital expenditure associated with purchase and maintenance of tools and equipment (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Tools and equipment | 0.28 | 0.05 | 0.05 | 0.05 | 0.05 | 0.48 |

Justification for the expenditure is that it is necessary to provide new maintenance teams with tools and equipment at a cost in 2000 of $282,000, and expenditure of $50,000 per annum is necessary to maintain the tools and equipment.

The Regulator was not provided with information on costs of tools and equipment to enable an assessment of the reasonableness of the costs. The Regulator does, however, consider that the purchase of tools can be reasonably regarded as a necessary expenditure and as the cost is relatively small, the Regulator considers that it may reasonably be expected to pass the tests of section 8.16 of the Code. The Regulator considers, however, that costs of maintaining tools and equipment should be considered as an operating cost and be taken into account in the determination of Reference Tariffs as a Non-Capital Cost. The Regulator will therefore require the forecast Capital Expenditure to be revised in accordance with the following costs for tools and equipment (1999 dollar values).[192]

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Tools and equipment | 0.23 | 0 | 0 | 0 | 0 | 0.23 |

**Inventory Management**

Epic Energy has forecast the following capital expenditure associated with studies to improve the management of a spare parts inventory (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Inventory management | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 1.00 |

The Regulator is of the view that this expenditure should be treated as an operating expenditure. The Regulator therefore requires that this forecast expenditure be removed from consideration as capital expenditure in determination of the Reference Tariff.[193]

**Emergency Response Caravan**

Epic Energy has forecast the following capital expenditure for the purchase of an emergency response caravan (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Emergency response caravan | 0 | 0.06 | 0 | 0 | 0 | 0.06 |

Justification provided for this expenditure is that it is essential to provide for voice and data communication for emergency incidents involving Epic Energy assets.

The Regulator accepts that this expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

**Corporate Head Office and Depots**

Epic Energy has forecast the following capital expenditure for the building works (converted to real 31 December 1999 dollar values).

[192] Refer to section 5.4.4.6 and Amendment 53 of this Draft Decision, relating to aggregate changes to forecasts of Capital Expenditure used for the purposes of determining the Reference Tariff.

[193] Refer to section 5.4.4.6 and Amendment 53 of this Draft Decision, relating to aggregate changes to forecasts of Capital Expenditure used for the purposes of determining the Reference Tariff.

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Buildings | 0.30 | 0.10 | 0.10 | 0.10 | 0.10 | 0.70 |

Justification provided in the Access Arrangement Information for this expenditure is that it is necessary for ongoing remodelling of offices ($100,000 per annum, unescalated) and for the building of a new warehouse ($250,000 in 2000 and $100,000 per annum, unescalated, thereafter).

The Regulator sought additional justification for this expenditure in response to which Epic Energy indicated that expenditure in 2000 is for remodelling of offices (GHD House) and a new warehouse (Jandakot depot). Planned capital expenditures in subsequent years are for works on yards and buildings at Compressor Stations 1, 5 and 8, and at Epic Energy's Jandakot depot. These works are expected to comprise:

- yards
- enhanced security
- installation of lighting
- construction of containments to prevent environmental contamination from hazardous chemicals;
- drainage;
- buildings;
- changes to work centres;
- replacement and upgrading of air conditioning systems;
- AC power backup facilities;
- batteries; and
- installation of fire detection systems.

The Regulator accepts that this expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

**Security Systems**

Epic Energy has forecast the following capital expenditure for the improvement of security at the Jandakot depot (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Security systems | 0 | 0.10 | 0 | 0 | 0 | 0.10 |

The Regulator accepts that this expenditure is reasonably likely to meet the requirements of section 8.16 of the Code.

**Fitness for Purpose Project**

Epic Energy forecast capital expenditure for a study of pipeline integrity and the safety factor built into the pipeline system as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Fitness for purpose project | 0.60 | 0 | 0 | 0 | 0 | 0.60 |

Epic Energy has indicated that this expenditure is necessary for completion of a study which is necessary to meet obligations imposed on Epic Energy under the pipeline licensing provisions of the *Energy Coordination Act 1994*, although information gained from the study would be of use to Epic Energy in planning future enhancement of pipeline capacity. Technical advice obtained by the Regulator indicated that one component of the study would be to assess the potential for increasing the maximum allowable operating pressure of the pipeline, which would enable a significant increase in pipeline capacity with a reasonably small capital investment. In view of this component of the study, the Regulator considers that the expenditure may be regarded as capital expenditure that could reasonably be expected to pass the tests of section 8.16 of the Code.

**Corrosion Protection Upgrades**

Epic Energy has forecast capital expenditure on corrosion protection as follows (converted to real 31 December 1999 dollar values).

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Corrosion protection upgrades | 0 | 0 | 0.02 | 0.02 | 0.02 | 0.06 |

The justification provided for this expenditure is that evidence of coating failure at certain sections of the pipeline necessitates installation of additional ground beds for the cathodic protection system.

The Regulator considers that this expenditure is reasonable and likely to pass the tests of section 8.16 of the Code.

**Land Management (GIS)**

Epic Energy forecast expenditure of $60,000 in 2000 for procurement and installation of a geographic information system for use in land management. The justification provided for the expenditure is reduced costs for management of environmental damage, die back and weed control, and a reduction in construction costs through streamlining of data capture.

The Regulator considers that Epic Energy has not provided adequate justification for this expenditure, but notes that GIS technology is routinely used for environmental management in operations such as with the DBNGP. On this basis, the Regulator considers that the expenditure may reasonably be expected to pass the tests of section 8.16 of the Code.

### 5.4.4.6 Conclusion

In view of the above assessment of Epic Energy's forecast Capital Expenditure, the Regulator will require the following amounts to be removed from the forecasts of Capital Expenditure taken into account in the determination of the Reference Tariff and transferred to either Non-Capital Costs or the Initial Capital Base.

**Reductions to Forecast Capital Expenditure (1999 $million, year ending 31 December)**

| Type of Investment | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| **Items transferred to Non-Capital Cost** | | | | | | |
| Flood damage mitigation | | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |
| Mainline valve GEA upgrades | | 0.04 | 0.04 | 0.04 | | 0.12 |
| Tools and equipment | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.25 |
| Inventory management | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 1.00 |
| **Items transferred to ICB** | | | | | | |
| Stage 3A enhancement | 19.49 | | | | | 19.49 |
| **Total** | **19.74** | **0.34** | **0.34** | **0.34** | **0.30** | **21.06** |

Of the above reductions, amounts indicated for the cost classifications of flood damage mitigation, GEAs upgrade, tools and equipment and inventory management should be incorporated in Non-Capital Costs for the respective years of the Access Arrangement Period. The amount of expenditure designated for Stage 3A compression enhancement has been added to the 1999 valuation of the Initial Capital Base rather than being considered as Capital Expenditure in 2000.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 53

The proposed Access Arrangement and Access Arrangement Information should be amended to reflect Capital Expenditure as follows (31 December 1999 $million).

| Year ending 31 December | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Pipeline | 0.43 | 0.23 | 0.11 | 0.31 | 0.11 | 1.18 |
| 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 | 9.67 | 10.33 | 6.91 | 2.53 | 35.89 |

In the assessment of proposed Capital Expenditure, the Regulator noted 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 this 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.

Epic Energy may wish to consider providing the Regulator with more rigorous justification for these projects before undertaking the associated expenditure (in accordance with provisions of section 8.21 of the Code).

## 5.5 NON-CAPITAL COSTS

### 5.5.1 Access Code Requirements

Section 8.36 of the Code defines Non-Capital Costs as the operating, maintenance and other costs incurred in the delivery of a Reference Service.

Section 8.37 of the Code provides for a Reference Tariff to recover 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.

### 5.5.2 Access Arrangement Proposal

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** |

### 5.5.3 Submissions from Interested Parties

#### 5.5.3.1 Scope of Submissions

Submissions on the proposed Access Arrangement addressed the following matters in relation to Non-Capital Costs.

- The adequacy of justification provided for the forecast Non-Capital Costs.

- Treatment of compressor fuel costs in determination of the Reference Tariffs.
- Treatment of corporate overhead costs.
- Marketing costs.

The submissions on each of these issues are indicated below together with the Regulator's response.

### 5.5.3.2 Justification for Costs

- WMC

  The AAI is deficient in the area of providing the details of Operations and Maintenance costs and cost breakdowns as required by the Gas Code.

  Future operations and maintenance expenditures should be reviewed in detail by competent independent and expert consultants and allowed only to the extent that they are at efficient (best practice) expenditure levels and matched to the reasonably expected levels of throughput during the Access Period.

  We would, however, make the comment that operations and maintenance costs on the DBNGP, by some comparisons, appear to be high, and a detailed justification is needed. We believe the charges should be linked to the drivers of actual costs; in such a way as to provide an incentive to reduce costs and that all stakeholders share in the benefit of reduced costs.

- AlintaGas Submission 3

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

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

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

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

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

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

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

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

- Robe River Mining

  We request that the Regulator verify that Epic's forecasted Non-Capital Costs of $39.11 million and increasing to $46.84 million in 2004 are reasonable.

In considering the Non-Capital Costs proposed by Epic Energy, the Regulator is required to make a determination on whether these costs meet the requirements of section 8.37 of the Code, that is, whether the proposed costs are consistent with the costs that would 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. No information was provided by Epic Energy in the Access Arrangement Information, or otherwise to the Regulator, to support such a determination.

In undertaking the assessment, the Regulator noted that the forecasts of Non-Capital costs do not limit or constrain Epic Energy as to the level or composition of Non-Capital Costs actually realised over the Access Arrangement Period. For this reason, the Regulator gave attention to both the total level of Non-Capital Costs that will be recognised in the derivation of the Reference tariff, and individual cost components.

The Regulator's assessment of the forecast Non-Capital Costs comprised:

- an assessment of time trends in the total Non-Capital Costs;
- a comparison of Non-Capital Costs across different transmission pipelines; and
- an assessment of individual cost components and the assumptions for cost forecasts.

The assessment was based in part on technical advice provided by Connell Wagner.

The outcomes of the Regulator's assessment are summarised in section 5.4.4 of this Draft Decision.

#### 5.5.3.3 Compressor Fuel Costs

- WMC

  The proposed charge for compressor fuel needs to be linked with a published, understandable and reasonable gas price.

- Northwest Shelf Gas Submission No. 1

  Two variable charges (commodity charges) are proposed. The first is a Compressor Fuel Charge that is proposed to be levied monthly in arrears based on a Shipper's actual throughput through a Zone. To apportion the costs on the basis of throughput seems reasonable. The charge is proposed to be based on forecast compressor fuel gas use rather than actual use. This proposed basis for the charge ignores the fact that actual fuel gas use at each compressor station is metered and therefore actual quantities will be known at the end of the month when invoices are sent out. Often a compressor station or stations are not run at all times, for instance it is understood that in 1999 Compressor Station 9 was hardly used and Compressor Station 10 is yet to be used at all. Compressors are routinely idled at low speed during pipeline upsets or low demand to minimise fuel use. At some compressor stations two machines of different sizes (and therefore different power and fuel consumption) are installed.

  Indeed with the sophisticated information gathering systems Epic Energy has installed it might be possible for the daily gas usage of each Shipper to be apportioned to the actual fuel gas consumption of each compressor. In this way a Shipper who ships larger quantities in the DBNGP during a period of high demand would pay for the extra fuel gas that that event caused to be used, rather than having the fuel gas spread out across all Shippers over a month.

  To have the Compressor Fuel Charge levied on forecast consumption levels will not encourage Epic Energy to operate the pipeline and the compressors in an efficient manner. It might be far better for this charge to be based on actual usage subject to a maximum cap that could be benchmarked against the lower of historical performance or an industry norm.

- Western Power Submission 5

  Prior to Epic Energy lodging its proposed Access Arrangement, it made a presentation regarding what Western Power should expect in the proposed Access Arrangement.

  As part of that presentation, Epic Energy stated that there would be a provision in the proposal, which allowed Shippers to provide for their own compressor station fuel, in lieu of paying a Compressor Fuel Charge.

  Epic Energy has not included such a provision in the proposed Access Arrangement. The absence of such a provision in the proposal does not meet the requirements of Section 3.2(b) of the Code.

  The Regulator is requested to ensure that there is ability for Shippers to provide their own compressor station fuel, in lieu of paying a Compressor Fuel Charge.

In summary, the submissions addressed three matters in relation to compressor fuel costs:

- the cost estimates for compressor fuel should be demonstrated to be consistent with a reasonable gas price;
- charges for compressor fuel gas should be based on actual gas usage rather than forecasts of gas use; and
- Users should be able to provide fuel gas in lieu of paying the compressor fuel charge.

The Regulator's responses to these matters are as follows.

**Justification for Compressor Fuel Charges**

In additional information provided to the Regulator, Epic Energy indicated the assumed average unit costs of gas used in operations[194] and indicated that these costs reflect the average price of gas purchased through contracts with gas suppliers. The Regulator examined the costs and is satisfied that these unit costs for gas are reasonable.

**Charging for Fuel Gas on the Basis of Actual Gas Usage**

A system of charging for fuel gas based on actual gas usage would operate by removing charges for fuel gas from the Reference Tariff and applying the charge separately and above the Reference Tariff. The Regulator approved such a mechanism for charging for system use gas with the Parmelia Pipeline.

The Regulator does not consider there to be good reason to reject Epic Energy's proposal to base charges for fuel gas on the basis of gas forecasts rather than actual gas use. The Regulator considers that given the relatively constant operating conditions of the DBNGP, the use of fuel gas should be readily predictable. Further, the ex ante determination of fuel gas charges provides incentives for Epic Energy to increase the efficiency of fuel gas use as the benefits of cost savings would be captured by Epic Energy for the duration of the Access Arrangement Period.

**Provision by Users of Fuel Gas in Lieu of Gas Charges**

Epic Energy has indicated to the Regulator that that the decision 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.[195]

The Regulator is of the view that, given the contractual commitments of Epic Energy to gas purchases, that it would be contrary:

- to the provisions of the gas access regime which in section 2.25 of the Code seeks not to overturn pre-existing contractual arrangements; and
- to Epic Energy's legitimate business interests, which the Regulator is required to take into account under section 2.24(a) of the Code,

to Epic Energy's legitimate business interests to require the proposed Access Arrangement to be amended to allow Users to provide gas in lieu of paying a compressor fuel gas charge. However, the Regulator considers that Users should have the option to supply fuel gas in lieu

[194] Epic Energy, Proposed Access Arrangement under the National Access Code, Information Request 17: System Use Gas, 16 March 2001.

[195] Epic Energy, Proposed Access Arrangement under the National Access Code, Information Request 17: System Use Gas, 16 March 2001.

of paying the Compressor Fuel Charge after expiry of Epic Energy's current contracts for purchase of gas for this purpose.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 54

The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to make provision after 2005 for Users of the Firm Service to provide fuel gas in lieu of payment of the Compressor Fuel Charge.

#### 5.5.3.4 Corporate Overhead Costs

- Northwest Shelf Gas Submission No. 1

  The split of overheads between Epic Energy's various pipelines is worth considering and the Regulator should determine what has been claimed for these other pipelines. We request that the Regulator satisfy himself that the costs are justified, are as low as reasonably practicable and that measures to reduce these costs are in place.

- Western Power Submission 3

  The approach taken in dealing with overheads and marketing is deficient in that if these costs have been previously allocated between Epic Energy's different operations on the basis stated, then under Access Arrangements or contracts in place, the Epic Energy business units in South Australia and Queensland will be recovering costs on a different basis than this allocation would now provide. To that extent, the proposed allocation will result in an over-recovery in this Access Arrangement Period.

In assessing the Non-Capital Costs proposed by Epic Energy, the Regulator did not give attention to the allocation of costs between the different pipeline operations of Epic Energy. Rather, the Regulator assessed these costs on the basis of historical costs. On the basis of Epic Energy's forecast costs being consistent with historical costs and there being a slight decrease in the real value of these costs over the Access Arrangement Period, the Regulator is prepared to accept this cost component as reasonable.

#### 5.5.3.5 Marketing Costs

- Western Power Submission 3

  There is no breakdown of the corporate overhead and marketing costs and therefore it is not possible to identify components, but it would be reasonable to have marketing costs identified separately and justified.

Epic Energy provided a breakdown of corporate overhead and marketing costs in the Access Arrangement Information (section 4.1). The Regulator deliberations on the reasonableness of the forecast costs are set out in section 5.5.4 of this Draft Decision.

### 5.5.4 Additional Considerations of the Regulator

#### 5.5.4.1 Transfer of Capital Expenditure Items

The Regulator indicated in the discussion of Capital Expenditure in this Draft Decision (section 5.4) that several cost line items included in the forecast of Capital Expenditure should be regarded as Non-Capital Costs and addressed as such for the purposes of determination of Reference Tariffs. These costs were as follows.

**Forecast Capital Expenditure reallocated to Non-Capital Costs (1999 $million, year ending 31 December)**

| Type of Investment | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Flood damage mitigation | 0 | 0.05 | 0.05 | 0.05 | 0.05 | 0.20 |
| Mainline valve GEA upgrades | 0 | 0.04 | 0.04 | 0.04 | 0 | 0.12 |
| Tools and equipment | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.25 |
| Inventory management | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 1.00 |
| **Total** | **0.25** | **0.34** | **0.34** | **0.34** | **0.30** | **1.57** |

Addition of these cost items to Epic Energy's forecast Non-Capital Costs gives the following revised Non Capital Costs.

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

| Expenditure category | 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 |
| Transferred from Capital Expenditure | **0.25** | **0.34** | **0.34** | **0.34** | **0.30** | **1.57** |
| **Total** | **38.41** | **39.63** | **41.88** | **42.14** | **41.70** | **203.76** |

In considering the Non-Capital Costs proposed by Epic Energy, the Regulator is required to make a determination on whether these costs meet the requirements of section 8.37 of the Code, that is, whether the proposed costs are consistent with the costs that would 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. No information was provided by Epic Energy in the Access Arrangement Information, or otherwise to the Regulator, to support such a determination.

In undertaking the assessment, the Regulator noted that the forecasts of Non-Capital costs do not limit nor constrain Epic Energy as to the level or composition of Non-Capital Costs actually realised over the Access Arrangement Period. For this reason, the Regulator gave attention to both the total level of Non-Capital Costs that will be recognised in the derivation of the Reference tariff, and individual cost components.

The Regulator's assessment of the forecast Non-Capital Costs comprised:

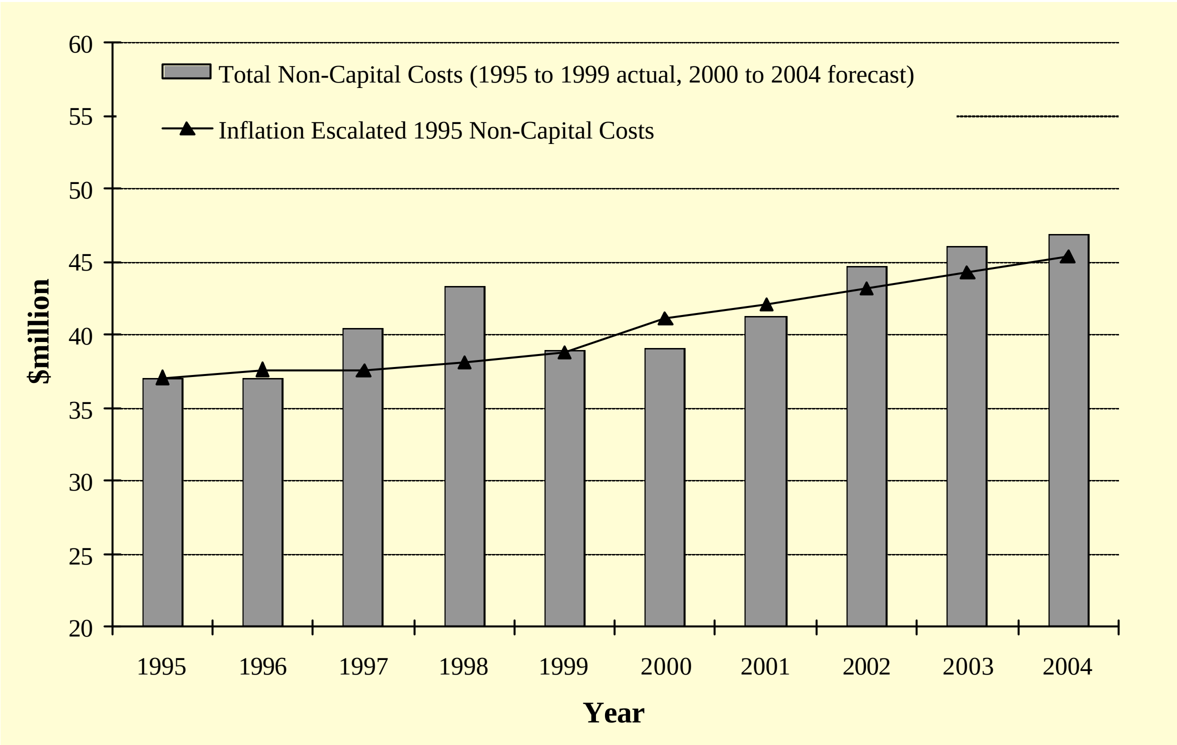
- an assessment of time trends in the total Non-Capital Costs;
- a comparison of Non-Capital Costs across different transmission pipelines; and

- an assessment of individual cost components and the assumptions for cost forecasts.

The assessment was based in part on technical advice provided by Connell Wagner.

### 5.5.4.2 Time Trends in Non-Capital Costs

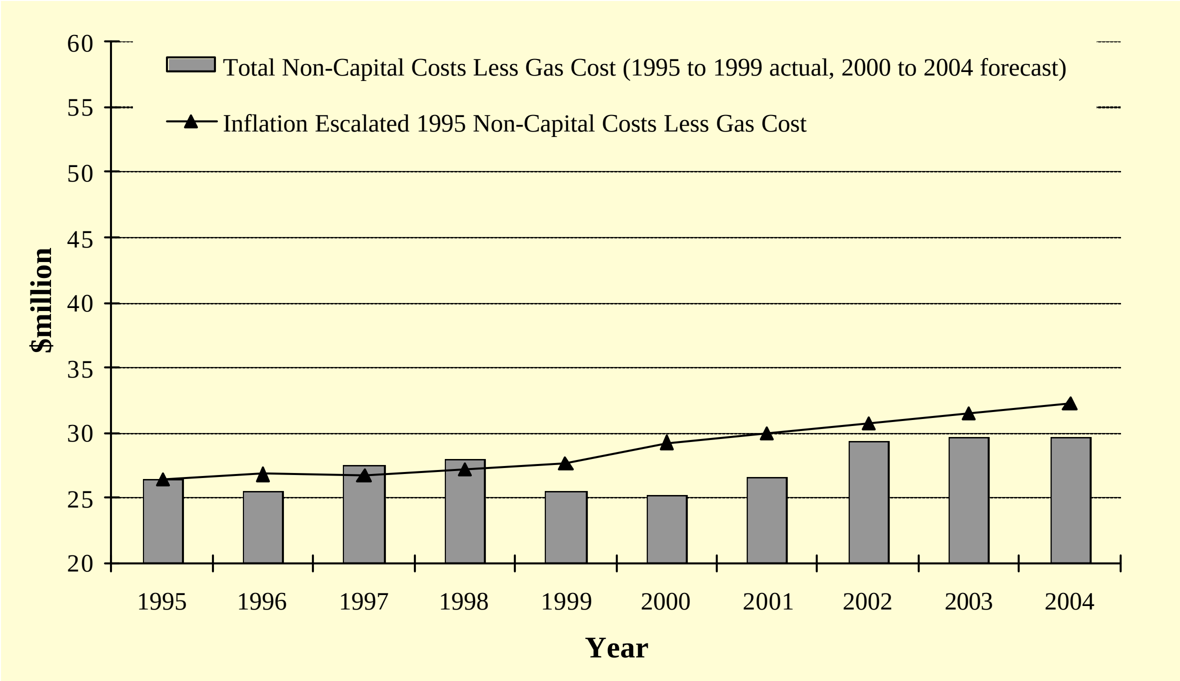
Historical and projected Non-Capital Costs for the DBNGP are shown in two figures below, the first being for total Non-Capital Costs and the second being for Non-Capital Costs net of the costs of gas used in operations. Each figure also shows the 1995 Non-Capital Costs escalated by actual or projected inflation.[196]




**Historical and Projected Non-Capital Costs (nominal $million)**[197]

[196] Inflation determined for 1995 to 2000 as the percentage change in the Eight Capital City, All-Groups CPI measure as published by the Australian Bureau of Statistics, and assumed at 2.5 percent per annum for 2001 to 2004.

[197] Costs from 2000 to 2004 are forecast Non-Capital Costs as indicated in the Access Arrangement Information. Costs for 1995 to 1999 are derived from historical data provided to the Regulator by Epic Energy. (Epic Energy's response to information request 16 June 2000.) For 1995 and 1998, cost data are for part of the relevant year and are scaled by number of days to obtain an estimate of Non-Capital Costs for the full year.




**Historical and Projected Non-Capital Costs Less Costs of Gas Used in Operations (nominal $million)**[198]

The time series of total Non-Capital Costs indicates an increase in costs at a rate greater than the rate of inflation over the periods 1995 to 2004 and 1999 to 2004. Sharp increases in costs occurred in 1997 (nine percent) and 1998 (seven percent) and are forecast to occur in 2002 (eight percent). These sharp increases in costs are also evident in the time series of Non-Capital Costs net of costs of gas used in operations, although in this case the increase in costs is less than the general rate of inflation for the period 1995 to 1999, but approximately the same as the assumed rate of inflation (2.5 percent per annum) for the period 1999 to 2004. Increases in Non-Capital Costs subsequent to 2002 appear almost entirely due to increased costs of gas used in operations, amounting to some $1 million per year, corresponding to annual increases in gas costs of between four and seven percent.

The Regulator sought from Epic Energy explanations for a projected rise in costs of materials and services that is the principal cause of the sudden increase in Non-Capital Costs in 2002, and the increases in projected costs of gas used in operations for the period 2002 to 2004. These matters are addressed below in relation to examination of individual line items of Non-Capital Costs (section 5.5.4.4 of this Draft Decision).

The Regulator notes that Epic Energy has not included in the Access Arrangement Information more detailed information on performance indicators that would enable a more detailed assessment of time trends in Non-Capital Costs both at the current time and upon future reviews of the Access Arrangement. Category 6 of Attachment A to the Code requires the inclusion of performance indicators in an Access Arrangement Information for a Covered Pipeline.

[198] Costs from 2000 to 2004 are forecast Non-Capital Costs as indicated in the Access Arrangement Information. Costs for 1995 to 1999 are derived from historical data provided to the Regulator by Epic Energy. For 1995 and 1998, cost data are for part of the relevant year and are scaled by number of days to obtain an estimate of Non-Capital Costs for the full year.

While work is still progressing in Australia toward the development of appropriate benchmarks for the gas pipeline and other regulated industries,[199] the Regulator considers that the Access Arrangement Information for the DBNGP should be amended to include additional information on performance indicators. A list of performance indicators that should be included for the Access Arrangement Period is as follows.

- Pipeline maintenance cost ($ per km of pipeline).
- Compression maintenance cost ($ per MW installed).
- Compression unit reliability (ratio of out of service hours to total hours).
- Compressor unit utilisation (ratio of run hours to total hours).
- Pipeline utilisation (ratio of average throughput to maximum capacity).
- Capacity reservation utilisation (ratio of average throughput to capacity reservation).
- Compressor fuel usage (ratio of compressor fuel to throughput).
- Maintenance cost ratio (ratio of operation and maintenance cost to total operating expenditure excluding fuel).
- Overhead cost ratio (ratio of overheads to total operating costs excluding fuel).
- Delivery cost (ratio of total operating costs excluding fuel to total quantity delivered).
- Gas unaccounted for (volume of gas unaccounted for as a percentage of total delivery).
- Delivery disruption (disrupted quantity as a percentage of total MDQ).

The following amendment is required before the proposed Access Arrangement will be approved**.**

Amendment 55

The Access Arrangement Information should be amended to include the following Key Performance Indicators for the Access Arrangement Period.

Pipeline maintenance cost ($ per km of pipeline).
Compression maintenance cost ($ per MW installed).
Compression unit reliability (ratio of out of service hours to total hours).
Compressor unit utilisation (ratio of run hours to total hours).
Pipeline utilisation (ratio of average throughput to maximum capacity).
Capacity reservation utilisation (ratio of average throughput to capacity reservation).
Compressor fuel usage (ratio of compressor fuel to throughput).
Maintenance cost ratio (ratio of operation and maintenance cost to total operating expenditure excluding fuel).
Overhead cost ratio (ratio of overheads to total operating costs excluding fuel).
Delivery cost (ratio of total operating costs excluding fuel to total quantity delivered).
Gas unaccounted for (volume of gas unaccounted for as a percentage of total delivery).
Delivery disruption (disrupted quantity as a percentage of total MDQ).

[199] Two discussion papers on benchmarking and incentive regulation have in recent times been prepared through the Utility Regulators Forum chaired by the ACCC:

(1) ACCC "The role of benchmarking in incentive regulation: An ACCC perspective", 22 July 1999; and

(2) ACCC "Incentive regulation, benchmarking and utility performance", November 2000.

#### 5.5.4.3 Cost Comparisons Across Transmission Pipelines

The Regulator compared forecast Non-Capital Costs for the DBNGP with Non-Capital Costs for two other transmission pipelines in Australia: the Moomba to Adelaide Pipeline and the Moomba to Sydney Pipeline. Comparative data are shown below.[200]

**Comparison of Non-Capital Costs across comparable Australian transmission pipelines**

| **Service Provider** | **EAPL** | **Epic Energy** | **Epic Energy** |
|---|---|---|---|
| Pipeline | Moomba to Sydney | Moomba to Adelaide | DBNGP |
| Data year | 2000/01 | 2000 | 2000 |
| *System Characteristics* | | | |
| Total pipeline length (km) | 2024 | 1849 | 1845 |
| Compressor stations | 3 | 8 | 10 |
| Gas transported (TJ/day) | 274 | 218 | 533 |
| *Non-Capital Costs* | | | |
| Total Non-Capital Costs ($million) | 12.179 | 14.866 | 39.110 |
| Non-Capital Costs excl. fuel gas ($million) | 11.279 | 11.366 | 25.210 |
| *Cost Ratios* | | | |
| Total Non-Capital Costs per km of pipeline ($'000) | 9.376 | 19.035 | 27.956 |
| Non-Capital Costs excl. fuel gas per km of pipeline ($'000) | 8.683 | 14.553 | 18.020 |
| Total Non-Capital Costs per TJ per km of pipeline ($) | 0.060 | 0.101 | 0.109 |
| Non-Capital Costs excl. fuel gas per TJ per km of pipeline ($) | 0.056 | 0.077 | 0.070 |

Non-Capital Costs of the three pipelines are compared by use of indices of cost per kilometre of pipeline and cost per terajoule of gas delivered per kilometre of pipeline. Costs are examined both as total Non-Capital Costs and Non-Capital Costs exclusive of the costs of fuel gas.

Non-Capital costs for the DBNGP appear high in all comparisons, being substantially higher than for the other two pipelines on a per-kilometre of pipeline basis. While the higher costs of the DBNGP in comparison to the Moomba to Adelaide Pipeline may be explained at least in part by the greater use of compression on the DBNGP, and hence the need to meet costs of compressor maintenance and fuel gas, the higher costs of the DBNGP in comparison with the Moomba to Sydney Pipeline can not be explained in the same manner. In particular, the DBNGP appears to have relatively high Non-Capital Costs, excluding fuel gas, per kilometre of pipeline, and high Non-Capital Costs, excluding fuel gas, per terajoule of gas throughput per kilometre of pipeline. Economies of scale in Non-Capital Costs arising from greater

[200] Data for the Moomba to Adelaide Pipeline derived from the ACCC Draft Decision 16 August 2000 and Access Arrangement documents. Data for the Moomba to Sydney Pipeline derived from the ACCC Draft Decision 19 December 2000 and Access Arrangement documents.

throughput do not appear evident for the DBNGP in comparison with the Moomba to Sydney Pipeline.

#### 5.5.4.4 Individual Components of Non-Capital Costs

The assessments of time trends in Non-Capital Costs and comparisons of Non-Capital Costs for the DBNGP with those for other pipelines caused the Regulator to have the following concerns with the forecast Non Capital Costs for the DBNGP.

- A sharp increase in Non-Capital Costs between 2001 and 2002, arising primarily in costs other than compressor fuel gas.
- Relatively high Non-Capital Costs of the DBNGP in comparison with other pipelines, and the absence of any apparent economies of scale accruing to operation of the DBNGP by virtue of its high gas throughput.

In view of these concerns, the Regulator gave attention to individual cost components in the forecast of Non-Capital Costs.

Epic Energy divided Non-Capital Costs into the following categories:

- wages and salaries;
- materials and services;
- property taxes;
- marketing;
- corporate overheads; and
- gas used in operations.

Epic Energy also provided a breakdown of Non-Capital Costs by category of activity as follows (converted to 1999 dollar values).

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

| Activity | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Pipeline maintenance | 10.38 | 9.98 | 10.00 | 10.04 | 10.10 | 50.50 |
| Compressor maintenance | 3.54 | 3.55 | 5.41 | 5.79 | 5.10 | 23.39 |
| Compressor fuel | 12.73 | 13.28 | 13.26 | 14.01 | 14.44 | 67.73 |
| Other costs | 11.51 | 12.48 | 12.87 | 11.96 | 11.75 | 60.56 |
| Total | 38.16 | 39.29 | 41.54 | 41.80 | 41.40 | 202.19 |

In regard to the sudden increase in Non-Capital Costs in 2002, the breakdown of costs by activity indicates that this increase is primarily due to a $2.1 million or 56 percent increase in expenditure on compressor maintenance.

The Regulator has noted that the increases in costs arise as a result of scheduled works for individual compressors, most notably for compressor overhauls. These costs are considered reasonable and consistent with the requirements of section 8.37 of the Code.

Increases in Non-Capital Costs over the Access Arrangement Period are also attributable to increases in costs of gas used in operations. Gas used in operations comprises fuel gas for compressors and gas used in all other operational activities, including the volume of gas vented during maintenance, but excluding gas vented during major construction.

Epic Energy has indicated to the Regulator that the forecast costs of gas used in operation underlying the Reference Tariff as described in the proposed Access Arrangement were in need of revision and subsequently submitted revised figures to the Regulator.[201] The original and revised figures are indicated as follows.

**Epic Energy forecast costs of gas used in operations: Access Arrangement and corrected values (1999 $million, year ending 31 December)**

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Reference Tariff Model | | | | | |
| Compressor fuel | 12.73 | 13.28 | 13.26 | 14.01 | 14.44 |
| Gas used in blowdowns, purges, etc | 0.75 | 0.82 | 1.07 | 0.93 | 0.78 |
| Total | 13.48 | 14.10 | 14.34 | 14.94 | 15.23 |
| Revised figures | | | | | |
| Compressor fuel | 12.45 | 13.07 | 13.30 | 13.92 | 14.22 |
| Gas used in blowdowns, purges, etc | 1.03 | 1.03 | 1.04 | 1.02 | 1.01 |
| Total | 13.48 | 14.10 | 14.34 | 14.94 | 15.23 |

On the basis of information provided by Epic Energy and technical advice from Connell Wagner, the Regulator examined the forecast costs of gas used in operations. The Regulator noted that the forecast cost of compressor fuel gas increases fourteen percent between 2000 and 2004 while throughput in the DBNGP is only forecast to increase by five percent over the same period, and is concerned that the increase in costs of fuel gas may be excessive. However, after review of information provided by Epic Energy in relation to the estimation of the use of fuel gas, the Regulator considers that there is not sufficient technical justification to require amendment of the forecast quantities and costs of fuel gas.

The Regulator also gave attention to cost categories of corporate overheads and marketing.

Corporate overhead costs are derived as an approximately 60 percent part of executive and administrative costs for Epic Energy's Australian operations, with the proportion derived on the basis of the combination of proportion of total labour costs for each operation and the proportion of total operating and maintenance costs (excluding fuel costs) for each operation.[202] The Regulator notes from information provided by Epic Energy that the Non-Capital Costs attributed to corporate overheads of $4.0 million to $4.3 million per annum are less than the average annual corporate overhead costs of the period 1995 to 2000 ($4.8 million) and the trend is for these costs to be increasing at approximately 2 percent per

[201] Revised figures as indicated by Epic Energy 16 March 2001, Dampier to Bunbury Natural Gas Pipeline, Proposed Access Arrangement under the National Gas Code, Information Request 17: System Use Gas.
[202] Access Arrangement Information, p 58.

annum in nominal terms. On the basis of the forecast costs being consistent with historical costs and there being a slight decrease in the real value of these costs over the Access Arrangement Period (given Epic Energy's assumed annual inflation rate of 2.5 percent), the Regulator is prepared to accept this cost component as reasonable.

The marketing costs forecast by Epic Energy of $0.45 million increasing to $0.5 million over the Access Arrangement Period are substantially higher than historical costs of 1998 and 1999: $18,000 and $95,000 for each year respectively. Epic Energy has provided no explanation for this difference, nor provided information that would enable the Regulator to be satisfied that such costs are consistent with the requirements of section 8.37 of the Code. However, the Regulator is mindful of the potential for increased marketing costs for the DBNGP as downstream gas and electricity markets are deregulated, and also of Epic Energy's likely desire to increase pipeline throughput to pursue the realisation of throughput forecasts made at the time of sale of the pipeline in 1997/98. In view of these factors, the Regulator is of the view that the marketing costs may reasonably be expected to comply with the requirements of section 8.37 of the Code.

#### 5.5.4.5 Conclusion

In assessing Epic Energy's forecast Non-Capital Costs for the DBNGP, the Regulator has noted that the forecasts have not been substantiated or supported to indicate that the forecast costs are consistent with the requirements of section 8.37 of the Code. That is, 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.

The Regulator notes that the forecast costs appear high relative to historical Non-Capital Costs and the Non-Capital Costs of comparable transmission pipelines. Further, Non-Capital Costs are forecast to increase at a rate greater than Epic Energy's assumed rate of inflation for the Access Arrangement Period.

In giving attention to the individual components of Non-Capital Costs the Regulator has some concern that the increase in costs of fuel gas may be excessive. However, after review of information provided by Epic Energy in relation to the estimation of fuel gas use, the Regulator considers that there is not sufficient technical justification to require amendment of the forecast quantities and costs of fuel gas.

In total, the Regulator notes the concerns indicated above in relation to Non-Capital Costs but does not consider that there is sufficient technical justification at the current time to seek amendment of these costs on the basis of these concerns. As such, the Regulator's required amendments to Non-Capital Costs are limited to the transfer of costs from Capital Expenditure, indicated as follows.

**Revisions to forecast Non-Capital Costs (1999 $million, year ending 31 December)**

| | 2000 | 2001 | 2002 | 2003 | 2004 | Total |
|---|---|---|---|---|---|---|
| Epic Energy proposed costs | 38.15 | 39.29 | 41.55 | 41.80 | 41.40 | 202.19 |
| *plus* | | | | | | |
| Costs transferred from Capital Expenditure | 0.25 | 0.34 | 0.34 | 0.34 | 0.30 | 1.57 |
| **Revised Non Capital Costs** | **38.41** | **39.63** | **41.88** | **42.14** | **41.70** | **203.76** |

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 56

The proposed Access Arrangement and Access Arrangement Information should be amended to reflect 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 | 39.63 | 41.88 | 42.14 | 41.70 | 203.76 |

## 5.6 RATE OF RETURN

### 5.6.1 Access Code Requirements

Sections 8.30 and 8.31 of the Code state the principles for establishing the Rate of Return for an existing Covered Pipeline when a Reference Tariff is first proposed for a Reference Service. These principles apply to the current Access Arrangement for the DBNGP.

Section 8.30 of the Code requires that 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).

Section 8.31 states that, 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 of the Code, as listed in section 5.1 of this Draft Decision.

### 5.6.2 Access Arrangement Proposal

For the purposes of determining Total Revenue, Epic Energy calculated an annual return on the Capital Base for the DBNGP by applying a pre-tax nominal rate of return to the sum of the physical asset account balance and a deferred recovery account balance at the end of the preceding year. The rate of return used in these calculations was determined as a weighted average of the returns (weighted average cost of capital or WACC) applicable to the assumed levels of equity and debt used to finance the DBNGP's regulated activities.

Epic Energy's estimate of the WACC associated with these activities is described in Appendix 2 of the Access Arrangement Information. It used the capital asset pricing model (CAPM) to estimate the WACC. The parameter values used by Epic Energy for this estimation the calculation 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).

**Epic Energy estimation of the Rate of Return**

| Capital asset pricing model parameter | Value used by Epic Energy |
|---|---|
| Risk free rate (nominal) | 6.40% |
| Market risk premium | 6.50% |
| Asset beta | 0.58 |
| Equity beta | 1.15 |
| Debt beta | 0.12 |
| Cost of debt margin | 1.20% |
| Corporate tax rate | 36% |
| Franking credit value[203] | 0.308% |
| Debt to total assets ratio | 55% |
| Equity to total assets ratio | 45% |
| Annual inflation rate | 2.5% |

### 5.6.3 Submissions from Interested Parties and Considerations of the Regulator

#### 5.6.3.1 Overview and Calculation Methodology

Several submissions on the proposed Access Arrangement expressed concerns in regard to Epic Energy's proposed Rate of Return. Submissions from Hamersley Iron, Energy Markets Reform Forum, Western Power,[204] Wesfarmers, Cockburn Cement, Chamber of Commerce and Industry, Chamber of Minerals and Energy, Mark Neville MLC, Australian Gas Users Group, Apache Energy Limited, North West Shelf Gas and Robe River Mining expressed concerns that Epic Energy's proposed Rate of Return of 8.5 percent (pre-tax, real) appears high relative to rates of return of 7.0 to 7.75 percent (pre-tax, real) established for gas pipelines in other Australian states, and other regulated utilities in Australia and the United Kingdom, and/or relative to returns in the stock market generally.

[203] Derived from Epic Energy's stated franking credit (gamma) value of 0.44 scaled by a dividend payout ratio of 0.7 to give an effective dividend credit value of 0.308.

[204] Western Power Submission 3.

A view to the contrary was expressed by CMS Gas Transmission, which indicated that the proposed Rate of Return:

> … is, as a matter of principle and in the context of existing regulatory precedent, too low and acts as an impediment to State development generally and development of a second pipeline from the North West specifically. We are obliged to restate the fact that comparisons of rates of returns permissible in Victoria (and specifically comparisons of transmission lines to distribution networks) are neither valid nor relevant in the context of the Western Australian market.

CMS Gas Transmission indicated that squashing expectations of being able to achieve commercially realistic returns on investments is hardly conducive to promoting necessary confidence to foster investment in the Western Australian gas market, and that:

> There is definitely scope for improving the Australian regulatory process in so far as the application of assessments of WACC is concerned. Notwithstanding the foregoing comment regarding inappropriate comparisons, Regulators across the country have yet to come to an understanding of the distinctions between older, established assets (in the sense that the market is established) and new or greenfields infrastructure developments. The recognition of the role which commercial, technical and (more recently) regulatory risk plays in the assessment of viable rates of return is sadly lacking in both past regulatory decisions as well as the public (and all too academic) debate. Even from an academic perspective, when revenues are clamped, regulatory risk cannot be offset by higher required rates of return as would be the expected response for other increased commercial risks. CMS would hope that the independence of Western Australia's Regulator might allow the scope to break this economically repressive trend.

The Regulator assessed Epic Energy's proposed Rate of Return using the Capital Asset Pricing Model to estimate a Weighted Average Cost of Capital (WACC), the same approach as used by Epic Energy.

The Capital Asset Pricing Model (CAPM) is widely used by regulators overseas, particularly in the UK where it is used as the principal model for estimating the regulatory WACC, and is used extensively in both corporate finance and regulatory applications in Australia. The use by Epic Energy of CAPM theory to derive a WACC is therefore considered consistent with guidelines provided in section 8.31 of the Code.

The typical approach by regulators to date has been to use the CAPM to derive the "target" post-tax return or WACC, and then to make adjustments to the WACC for the net cost of taxation. At its simplest level, the CAPM specifies the WACC for an asset as a rate of return that can be earned by a risk-free asset plus a risk premium for the asset in question. The risk premium depends upon the risk of the particular asset relative to the risk associated with a diversified asset portfolio. Analytically:

$$WACC = R_f + b_a(R_m - R_f)$$

where $R_f$ is the risk free rate, $(R_m - R_f)$ is the expected risk premium above the risk free rate for the portfolio of all assets, and $b_a$ is the measure of the particular asset's relative risk, or its asset beta.[205]

In practice, asset betas cannot be observed or measured directly. Estimating a beta requires historical information on the economic returns to an asset (comprising the value of the returns plus the change in the market value of the asset), and on economic returns to the well-diversified portfolio of assets. As this type of information is only available on assets that are traded on the stock exchange, the CAPM is used to estimate the required return to the equity share of an asset, and stock market indices are used as a proxy for the market portfolio. Accordingly, the more common formulation of the CAPM is:

[205] Note that, under this version of the CAPM, there is no need for assumptions about the cost of debt or capital structure for the entity to estimate its WACC.

$$R_e = R_f + \beta_e (R_m - R_f)$$

where $R_f$ is still the risk free rate, but ($R_m - R_f$) is now the expected risk premium above the risk free rate for a well-diversified portfolio of equities, $\beta_e$ is the measure of the particular equity's relative risk, or its equity beta, and $R_e$ is the required return on that equity. The outcome of this model, therefore, is an estimate of the required after tax return to equity. The return required by the other source of financing – debt – can be observed directly from the market, and the average of these sources of financing (weighted by the respective shares of debt and equity in the financing of the asset) provides an estimate of the WACC for the asset. That is:

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

where $\frac{E}{V}$ and $\frac{D}{V}$ are equity and debt as shares of total assets, $V$, and $R_d$ is the cost of debt.

There are, however, a number of different versions 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. One popular form is the 'Officer' WACC, which has the following formula:

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

where $t_c$ is the corporate tax rate and $\gamma$ is the value of franking credits created (as a proportion of their face value).

In determining the Rate of Return, Epic Energy used a variation of the Officer WACC whereby the *gamma* term was replaced by a function of the utilisation of franking credits ($\theta$); the dividend payout ratio ($\alpha$); and a factor reflecting the ratio of franked dividends to total dividends ($k$). Its formula for the post tax WACC was therefore:

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

The Regulator has used the Officer WACC formula to estimate the cost of capital associated with the DBNGP's regulated activities. However, the merits of the alternative formulation to the 'gamma' term are discussed below (section 5.6.3.5 of this Draft Decision).

In estimating the WACC for the DBNGP, the Regulator made various assumptions as to the inputs into the CAPM. These assumptions took into account information from the capital markets, other regulatory decisions, public submissions on the proposed Access Arrangement, and submissions from Epic Energy.

The various elements of the CAPM model and the positions taken by Epic Energy and the Regulator on each element are discussed below.

Treasury/Office of Energy commented that there would be benefit in the Regulator requiring the use of a consistent methodology and transparently derived inputs for those parameters that are not company-specific (e.g. inflation, typical gearing ratios, market risk premia, tax rates and gamma (dividend payout and imputation credit utilisation) factors). The Regulator has taken account of some regulatory standards that have emerged in Australia for values of gearing, market risk premiums, dividend imputation factors and debt premiums that reflect either the economy-wide financial environment or which are considered common across all firms in the gas pipeline industry.

### 5.6.3.2 Market (Equity) Risk Premium

The market, or equity, risk premium ($R_m - R_f$) measures the risk associated with holding the market portfolio of investments. It is the difference between the expected return on holding the market portfolio, and the risk free rate.

Epic Energy has proposed a market risk premium of 6.5 percent supported by an argument that estimates made from historical stock market and government bond data suggest a range of six to eight percent and the absence of any reason to utilise a value outside of this range.[206] Furthermore, an argument was presented that an empirically estimated range of six to eight percent for the market risk premium may underestimate the true market risk premium by failing to take into account the value of franking credits.

**Submissions**

Submissions from Energy Markets Reform Forum, WMC, AlintaGas,[207] North West Shelf Gas, Robe River Mining and Treasury/Office of Energy commented that the market risk premium of 6.5 proposed by Epic Energy is higher than a usual range of 5.5 to 6.0 percent in Australian regulatory decisions.

**Considerations of the Regulator**

The analysis of historical returns is a popular method for estimating the expected equity premium. While the use of historical returns is somewhat at odds with the CAPM – which is unambiguously a "forward-looking" model – the use of a long-term historical average equity premium (a "backward-looking" equity premium) remains attractive, given the inherent volatility in equity markets.[208] The long-term simple averages of actual economic returns on a diversified share portfolio in Australia is generally taken to imply a point estimate of the underlying market risk premium of between 6 and 8 percent.

However, estimates of the historical premium to equity over the risk free rate[209] are also highly sensitive to assumptions such as the period over which the analysis is undertaken, whether an arithmetic or geometric average should be used, how changes in the taxation rate on equity are taken into account, and whether or not more weight should be given to the more recent stock market returns. The use of long term historical averages of stock market returns to estimate the expected equity premium have also been subject to a number of other criticisms. One is that the premium measured for countries such as the US, UK and Australia may be subject to 'survivorship bias'. In addition, the implicit assumption underpinning the

[206] Citing Officer, R.R., 1988, Rates of Return to Shares, Bond Yields and Inflation Rates: an Historical Perspective, University of Melbourne (Access Arrangement Information, Appendix 2 p 22). Epic Energy's consultants also noted that a simple average of the dividends and capital gains available fromthe stock market would understate the equity premium as it would ignore the value of franking credits. While this comment is correct in principle, it is understood that the historical estimates of the equity premium referred to here have either grossed-up the value of dividends to add-back an assumed franking yield, or cover periods that contain comparatively few observations from the post-imputation era. In addition, the *ex ante* studies referred to below also redefine dividend yield to include the value of franking credits.

[207] AlintaGas Submission 3.

[208] Note, however, that this volatility in stock market returns implies that the estimates of the underlying market risk premium from even very long-term simple averages are subject to substantial statistical uncertainty.

[209] The Government bond rate is generally used as a proxy for the risk free rate.

use of long-term historical estimates of the equity premium – which is that the premium has not changed over the averaging period – is also being seen as increasingly questionable. There is an emerging view, both in Australia and overseas, that the expected equity premium has fallen significantly in recent decades. This would imply that long-term averages of historical stock market returns might overstate the premium currently expected. The rationale for this view recently has been explained as follows.[210]

> One view in the finance literature [for the surprising historical size of the equity premium] … is market imperfections – things like the inability of investors to fully insure against major risks outside the organised stock markets, such as shocks to their labor income; the significant direct and indirect costs that investors face in order to make transactions; and incomplete knowledge about existing opportunities.
>
> …
>
> If this view is right, and the historical premium is primarily due to market imperfections, then the premium can reasonably be expected to shrink when such imperfections are reduced. That seems to be what has happened in the United States over the last three decades.

While care must be taken when comparing equity premia across countries, it is reasonable to expect that trends in the premium observed overseas may also be observed in Australia.

Other methods for estimating the market risk premium have also been used. One is the use of an "ex-ante" model, which involves projecting dividends for the whole market and estimating the equity premium by finding the discount rate that reconciles the dividend stream with the current market valuation. In work undertaken for the ACCC by an independent expert using this methodology, a range of 4.5 percent to 7.0 percent for the market risk premium has been suggested.[211] More recent calculations by the Office of the Regulator-General in Victoria suggested that this methodology would produce an estimate of the market risk premium of about 5 percent.[212] As with the use of historical estimates, *ex ante* estimates of the equity premium are also subject to measurement error and are sensitive to assumptions made about the growth rate of dividends.

Currently, a view is emerging that the equity premium is less than *point estimates* provided by long term historical averages.[213] Outside Australia, the weight of analysis is shifting towards a view that the equity premium has fallen as investor's perceptions of risks are changing. In the UK, for example, utility regulators currently use a range of between 3 percent and 4 percent for the equity premium,[214] although care must be taken when considering equity premiums from outside Australia because of the smaller size of the Australian equity market relative to those in the UK or US. Within Australia, many equity analysts now use equity premia that are at the lower end of, or below, the point estimates referred to above. Academic literature and commissioned research papers also generally

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[210] Jagannathan, McGrattan and Scherbina, 'The Declining US Equity Premium, National Bureau of Economic Research, Working Paper 8172, March 2001, p 2.

[211] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues* May 1999, pp 78-79.

[212] ORG, *Draft Decision: 2001 Electricity Distribution Price Review*, p 158.

[213] Note that a 95% confidence limit around any of these point estimates is likely to be ± 3 percentage points or wider.

[214] IPART, *Draft Decision, Access Arrangement for AGL Gas Networks Ltd*, October 1999, p 63.

indicate lower market risk premia, with estimated values in the range of three to seven percent.[215]

In light of the emerging consensus that the forward-looking equity premium is lower than the point estimates provided by long term historical averages, Australian regulators have been using an assumed equity premium that is at the lower end of, or below, these estimates. The accepted values of market (equity) risk premiums have been in the range 5 to 6 percent, as indicated below. In past regulatory decisions for Western Australian pipelines, the Regulator has consistently used a market risk premium of 6 percent.

**Equity premiums adopted in recent regulatory decisions**

| Regulatory decision | Market (equity) risk premium |
|---|---|
| ORG Final Decision on Victorian Gas Distribution (October 1998) | 6% |
| ACCC Final Decision on Victorian Gas Transmission (October 1998) | 6% |
| IPART Final Decision on Great Southern Network (March 1999) | 5% – 6% |
| IPART Final Decision on Albury Gas Company (December 1999) | 5% – 6% |
| IPART Final Decision on AGL Gas Networks Limited (July 2000) | 5% – 6% |
| ACCC AGL Final Decision on Central West Pipeline (June 2000) | 6% |
| ACCC TransGrid Draft Decision (May 1999) | 6% |
| ACCC Telstra's Originating and Terminating Access Undertaking (June 1999) | 6% |
| IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999) | 5% – 6% |

Having regard to the arguments put forward as to the evidence provided by long term averages of historical stock market returns, the information provided by other estimation methodologies and the emerging views that the equity premium currently expected may have fallen from historical levels (in line with changing perceptions of risk), the Regulator considers that a market risk premium of 6 percent should be used to estimate the WACC for the DBNGP.

#### 5.6.3.3 Rate of Return on Debt

The required rate of return on debt, $R_d$, is determined by the following expression:

$$R_d = R_f + \text{debt risk margin}$$

where $R_f$ is the nominal risk free rate.

[215] Relevant studies are cited by IPART in the October 1999 Draft Decision on the Access Arrangement for AGL Gas Network Limited's Natural Gas System in NSW, and the ACCC Draft Decision on the Access Arrangement for AGL Pipelines (NSW) Pty Ltd's Central West Pipeline.

Epic Energy has proposed a rate of return on debt of 7.60 percent (nominal) based on a nominal risk free rate of 6.4 percent and debt risk margin of 1.2 percent.

**Submissions**

Comments were made in submissions that Epic Energy's assumed risk free rate may be too low (WMC, Treasury/Office of Energy) or too high (AlintaGas[216]), with differences in opinion mainly relating to the time at which the risk free rate is estimated from yields on government bonds.

Submissions from WMC, AlintaGas,[217] North West Shelf Gas, Robe River Mining and Treasury/Office of Energy commented that this debt risk margin appears high given a low risk status of the DBNGP business and/or regulatory precedent in Australia.

**Considerations of the Regulator**

Risk Free Rate, $R_f$

Epic Energy has assumed a nominal risk free rate of 6.4 percent,

When a real WACC is used to determine regulated charges, it is the implied real risk free rate (rather than the nominal risk free rate) that is the relevant input parameter. Accordingly, the selection of the proxy for the risk free rate and the assumption about inflation need to be considered together. In recent years, Australian regulators have all adopted a very similar approach to deriving the proxy real risk-free rate, based on one or other of the following methods.

- Deriving the nominal risk free rate from a recent average (20, 30 or 40 days) 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.
- Using the yield on bonds with either 5 year or a 10 year yield to maturity.

Whilst the different approaches seldom have a material effect on the proxy real risk free rate, the Regulator has decided to use 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.

The difference between the two rates (calculated using the Fisher equation[218]) provides an inflation forecast over the relevant period. The use of Commonwealth capital indexed bonds has the advantage that it permits a market-based expectation of inflation to be taken into account. Other regulators have also used this approach to provide a measure of inflation.[219]

As at 31 May 2001, this gave a nominal risk free rate of 5.96 percent, a real risk free rate of 3.40 percent, and a forecast rate of inflation of 2.48 percent. These values have been used by the Regulator to revise the WACC for the DBNGP.

[216] AlintaGas Submission 3.

[217] AlintaGas Submission 3.

[218] Brealey, R.A. and Myers, S.C., 1996. *Principles of Corporate Finance*, fifth edition, New York McGraw–Hill, pp 642, 643.

[219] Independent Pricing and Regulatory Commission, ACTEW's Electricity, Water and Sewerage Charges for 1999/2000 to 2003/2004, Draft Price Decision, February 1999; and IPART, Aspects of the NSW Rail Access Regime, Draft Report, February 1999.

Debt Risk Margin

Epic Energy has adopted a debt risk margin (or corporate debt premium) of 1.2 percent.

In assessing the debt risk margin, the Regulator considered the debt margins adopted by regulators in recent regulatory decisions, indicated as follows.

**Recent regulatory decisions on debt margins**

| Regulatory decision | Range for debt margin | Point estimate |
|---|---|---|
| ORG Final Decision on Victorian Gas Distribution (October 1998) | 1.0% – 1.2% | 1.2% |
| ACCC Final Decision on Victorian Gas Transmission (October 1998) | 1.0% – 1.2% | 1.2% |
| IPART Final Decision on Great Southern Network (March 1999) | – | 1.2% |
| IPART Final Decision on Albury Gas Company (December 1999) | 0.9% – 1.1% | – |
| IPART Final Decision on AGL Gas Networks Limited (July 2000) | 0.9% – 1.1% | |
| ACCC AGL Final Decision on Central West Pipeline (June 2000) | – | 1.2% |
| IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999) | – | 1.0% |
| ACCC TransGrid Draft Decision (May 1999) | – | 1.0% |
| ACCC AGL Central West Pipeline Draft Decision (September 1999) | – | 1.0% |
| Independent Gas Pipelines Access Regulator (WA) Mid-West and South-West Distribution Systems Final Decision (June 2000) | – | 1.3% |
| Independent Gas Pipelines Access Regulator (WA) Tubridgi Pipeline Draft Decision (August 2000) | – | 1.2% |
| Independent Gas Pipelines Access Regulator (WA) Parmelia Pipeline Final Decision (October 2000) | – | 1.2% |
| Independent Gas Pipelines Access Regulator (WA) Goldfields Gas Pipeline Draft Decision (April 2001) | – | 1.2% |

Empirical evidence on debt margins is variable. The ACCC in its June 2000 final decision on the AGL's Central West Pipeline cited evidence to suggest that the debt margin was increasing at the time of that decision and increased the margin from 1.0 percent used in the draft decision to 1.2 percent. IPART, in its July 2000 final decision on the Access Arrangement for AGL's Natural Gas System in NSW, cited data for corporate bond issues by a range of energy utilities and Telstra indicating debt margins in the order of 1 percent.

In view of the empirical evidence for the possible range of debt margins and precedents of other regulatory decisions, the Regulator considers that it is reasonable to assume a debt margin of 1.2 percent for the DBNGP.

Return on Debt, $R_d$

Using the above estimates of the risk free rate and the debt risk margin, the nominal return on debt, $R_d$, was determined by the Regulator to be 7.16 percent, compared with 7.60 percent proposed by Epic Energy. As the Regulator has accepted Epic Energy's benchmark debt margin, this difference is due solely to the change in interest rates since Epic submitted its Access Arrangement.

#### 5.6.3.4 Rate of Return on Equity

The rate of return on equity, $R_e$, is determined using the following expression.

$$R_e = R_f + b_e(R_m - R_f)$$

where $R_f$ is the risk free rate, $(R_m - R_f)$ is the expected risk premium above the risk free rate for a well-diversified portfolio of equities, $b_e$ is the measure of the particular equity's relative risk, or its equity beta, and $R_e$ is the required return on that equity.

The application of the CAPM requires an equity beta, $b_e$, to be determined for the DBNGP business. The equity beta value reflects the relevant business's exposure to systematic risk, which relates to that portion of the variance in the return on an asset that arises from market-wide economic factors that affect returns on all assets, and which cannot be avoided by diversifying a portfolio of assets.

For a business entity not listed on the stock market, an equity beta is commonly estimated by estimating asset beta and debt beta values from observations of comparable listed entities and re-levering these into an equity beta that is consistent with the assumed capital structure of the entity being examined.

Epic Energy assumed an asset beta of 0.58, based on an average across a sample of five United States pipeline companies. With a gearing ratio assumed by Epic Energy of 0.55, this corresponds to an equity beta of 1.15.

**Submissions**

Submissions from Wesfarmers, WMC, AlintaGas,[220] North West Shelf Gas, Robe River Mining and Treasury/Office of Energy indicated that the asset/equity beta values assumed by Epic Energy are too high and do not reflect the low risk status of the DBNGP business or regulatory precedent in other Australian states. The submissions indicated that the low risk status of the DBNGP business purportedly arises from the large gas reserves of the Carnarvon Basin, monopoly status of the DBNGP, the large industrial component in demand for pipeline services with long service contracts and little seasonal variation in demand, and the high proportion of fixed charges in the proposed Reference Tariff.

Submissions from WMC, AlintaGas,[221] North West Shelf Gas, Robe River Mining and Treasury/Office of Energy suggested that the gearing ratio assumed by Epic Energy of 55 percent debt might be too low and suggested that a more appropriate assumption would be a gearing ratio of 60 to 75 percent.

[220] AlintaGas Submission 3.
[221] AlintaGas Submission 3.

## Considerations of the Regulator

Equity Beta, $b_e$

As noted above, the application of the CAPM requires an equity beta, $b_e$, to be determined for the DBNGP business. Since Epic Energy (WA) Transmission Pty Ltd does not comprise a listed company, it is necessary to use a proxy beta, normally derived from estimates of betas for listed firms that are considered to have a comparable degree of systematic risk. Systematic risk relates to that portion of the variance in the return on an asset that arises from market-wide economic factors that affect returns on all assets, and which cannot be avoided by diversifying a portfolio of assets. A beta value indicates the sensitivity of the value of the particular asset to systematic risk.[222]

In deriving a proxy beta, it must be borne in mind that the level of gearing that is adopted by the firm affects the level of risk faced by equity holders. An increase in the level of gearing, *ceterus paribus*, increases the financial risk that is borne by equity holders, and so increases the equity beta. A common practice to permit comparison of estimated betas across firms with different capital structures is to convert an estimated equity betas into an asset beta (which is the estimate of the equity beta on the assumption that the firm was wholly equity financed). As asset betas measure only the underlying market risk of the asset, they can be compared across firms regardless of capital structure. Accordingly, practice amongst regulators has been to determine a proxy asset beta, and then to re-lever this into an equity beta that is consistent with the assumed capital structure of the entity, using the following expression:

$$b_e = b_a + (b_a - b_d).\frac{D}{E}$$

where $b_a$ is the asset beta, $b_d$ is the debt beta (indicating the degree of systematic risk borne by the debt providers). The debt beta, $b_d$, is not directly observable, but in its decisions, the Regulator has estimated the debt betas as the ratio of the margin of the cost of debt above the nominal risk free rate to the market risk premium, which gives a value of 0.20 for the DBNGP. Epic Energy adopted a debt beta of 0.12.

The Office of the Regulator-General has recently considered in some detail the role of the debt beta when deriving a proxy asset beta. It emphasised the importance of using a consistent assumption about the debt beta when calculating asset betas from estimated equity betas, and when performing the operation in reverse to derive a proxy equity beta.[223] While the Regulator has not been convinced of a need to change the methodology for estimating debt betas, it will ensure that the asset betas relied upon are consistent with a debt beta of 0.20.

The appropriateness of a proxy asset beta is dependent upon the businesses for which beta estimates are available having a similar level of systematic risk. Since there are few comparable infrastructure entities listed on the Australian Stock Exchange, regulatory

[222] Peirson, G., Bird, R., Brown, R. and Howard, P., 1990. *Business Finance* 5th ed., New York, Sydney: McGraw-Hill, pp 96, 97. Systematic risk is also referred to as non-diversifiable risk as no amount of diversification in an asset portfolio can eliminate it. The second component of the total risk of an asset is unsystematic or diversifiable risk which relates to variance in the value of the asset that arises from factors specific to that asset. In principle, this risk can be eliminated from an asset portfolio by adequate diversification of that portfolio.

[223] Office of the Regulator-General, *Electricity Distribution Price Determination 2001-2005 – Vol 1: Statement of Purpose and Reasons*, pp 267-268.

practice in Australia has been to place weight upon publicly available beta estimates for firms that are operating in other countries. However, differences in the composition of equity markets between countries and differences in the taxation environment, regulatory regimes and other factors within which regulated businesses operate can affect the level of systematic risk that is borne by the businesses. Therefore an element of judgement must be exercised as to the appropriateness of the proxy betas.

Epic Energy assumed an asset beta of 0.58 (which would translate to an asset beta of 0.61 given the Regulator's assumed debt beta). This proxy beta was derived by estimating the equity beta for five United States pipeline companies, but in this estimation process, the US market portfolio was re-weighted to reflect the weights applicable to the different sectors in Australia. This process was undertaken to eliminate the concern that differences in the composition of the share market in different countries may affect the comparability of proxy betas.

The Regulator considers that Epic Energy's estimate of the proxy beta for gas transmission in Australia provides useful information about the likely magnitude of the asset beta for Australian transmission pipelines. However, it is noted that any such exercise involves an element of measurement error, and the method adopted cannot account for all of the differences in the factors that may impact on the levels of systematic risk borne by similar entities in different countries. Accordingly, it is considered reasonable also to have regard to the estimates of betas for Australian utility firms when forming a view on the proxy beta for DBNGP's regulated activities. The following range of beta estimates for Australian firms were recently presented by the Victorian Office of the Regulator-General.[224]

**Recent Estimates of Asset Betas for Australian Listed Utilities[225]**

| Source | Company | | | Average Asset Beta | Weighted-Average Asset Beta |
|---|---|---|---|---|---|
| | AGL | Envestra | United Energy | | |
| Bloomberg – Adjusted Betas | 0.59 | 0.30 | 0.40 | 0.43 | 0.40 |
| Bloomberg – Unadjusted Betas | 0.48 | 0.27 | 0.32 | 0.35 | 0.34 |
| AGSM – June 2000 | 0.62 | 0.24 | 0.56 | 0.47 | 0.35 |

The "Bloomberg adjusted betas" employed what is often referred to as the Blume adjustment, which has the effect of adjusting raw beta estimates towards the market average (i.e. 1). The ORG questioned the appropriateness of this adjustment when deriving a proxy beta for a stand-alone regulated activity. The 'weighted average' betas weight the individual beta

[224] The estimates from the different sources and with different adjustments have been provided to demonstrate the range of the potential empirical estimates from publicly available sources. These estimates only provide *independent* beta estimates for three firms, and one *independent* estimate of the average of those betas.

[225] These were obtained using the levering methodology and assumed debt beta employed in this *Draft Decision*.

estimates according to their relative precision. Thus, the more precise beta estimates make a greater relative contribution to the average.[226]

Moreover, given an objective of maintaining consistency across different regulatory decisions, it is also reasonable to have some regard to regulatory decisions for comparable businesses. Some of the proxy asset betas employed in O*ff*GAR's other decisions, and those of the more recent Australian regulatory decisions from other states, include the following.[227]

| **Asset betas adopted by Australian regulators** | |
|---|---|
| **Gas Regulatory Decisions – Western Australia** | **Asset Beta Value or Range** |
| Independent Gas Pipelines Access Regulator (WA) Final Decision on the Mid-West and South-West Gas Distribution Systems (June 2000) | 0.55 |
| Independent Gas Pipelines Access Regulator (WA) Draft Decision on the Tubridigi Pipeline (August 2000) | 0.65 |
| Independent Gas Pipelines Access Regulator (WA) Final Decision on the Parmelia Pipeline (October 2000) | 0.65 |
| Independent Gas Pipelines Access Regulator (WA) Draft Decision on the Goldfields Gas Pipeline (April 2001) | 0.65 |
| **Gas Regulatory Decisions – Other Regulators** | |
| ACCC Final Decision on Central West Pipeline (June 2000) | 0.72 |
| IPART Final Decision on AGL Gas Networks Limited (July 2000) | 0.48 – 0.56 |
| ACCC Draft Decision on the Moomba to Adelaide Pipeline (August 2000) | 0.58 |
| ACCC Draft Decision on the Moomba to Sydney Pipeline (December 2000) | 0.58 |
| ACCC Draft Decision on the NT Gas Pipeline (May 2001) | 0.58 |
| **Electricity Regulatory Decisions** | |
| Office of the Regulator General Electricity Distribution Price Determination 2001-05 (September 2000) | 0.52 |
| QCA Draft Decision on Allgas and Envestra (March 2001) | 0.51 |
| QCA Electricity Distribution Final Determination (May 2001 | 0.40 |

Having regard to the evidence provided by Epic Energy's empirical estimate of a proxy asset beta from US data (and adjusted for Australian market-weights), estimated asset betas for Australian utility firms, and the ranges for the asset betas that have been adopted by Australian regulators to date, the Regulator considers that a reasonable range for the asset beta of an Australian gas transmission business is 0.50 to 0.65 (for an assumed debt beta of

[226] These issues were discussed in some detail by the ORG: Office of the Regulator-General, *Electricity Distribution Price Determination 2001-2005 – Vol 1: Statement of Purpose and Reasons,* pp 273-276.

[227] These proxy betas have all been adjusted to be consistent with an assumed debt beta of 0.20. That is, the asset beta has been calculated as the weighted average of the equity beta that was employed in the relevant decision and a debt beta of 0.20.

0.20), and has adopted 0.60 for the purposes of estimating the cost of capital associated with DBNGP's regulated activities. This asset beta is practically identical to the value of 0.58 (or 0.61 for a debt beta of 0.20) adopted by Epic Energy.

Calculation of the equity beta from asset and debt betas also requires assumption of a gearing ratio for the DBNGP. Epic Energy assumed a financing structure comprising 55 percent debt and 45 percent equity. This gearing level is slightly less than gearing levels generally used in Australian regulatory decisions of 0.60.

In considering an appropriate gearing level, the Regulator noted the requirements of section 8.31 of the Code that requires that the weighted average return on funds should be calculated by reference to a financing structure that reflects standard industry structures. For the purposes of the Draft Decision, the Regulator has interpreted a "standard industry structure" as being the gearing level of a firm that would be consistent with an industry-grade credit rating. In this regard, the Regulator notes that Standard and Poors has observed median debt to asset ratios for transmission and distribution companies rated A to BBB of 55 to 65 percent.[228] The Regulator therefore considers a gearing level of 60 percent to be an appropriate assumption in determining the Rate of Return for the DBNGP.

Assuming a gearing (debt to equity) ratio of 60:40, an asset beta of 0.60 and a debt beta of 0.20, the equity beta is calculated to be 1.20. This is higher that the equity beta proposed by Epic Energy (1.15), but is practically the same once allowance is made for the differences in the assumed gearing levels.

Return on Equity, $R_e$

Using the above estimates of the equity beta, risk free rate and market risk premium, the nominal post tax return on equity, $R_e$, was estimated by the Regulator to be 13.16 percent, compared with 13.90 percent proposed by Epic Energy. This difference reflects three factors, which are: the fall in interest rates since Epic Energy submitted its Access Arrangement; the use of a higher equity beta than Epic Energy; and the Regulator's use of a lower market risk premium. The first of these factors is an exogenous event that Epic Energy's consultants assumed would be passed-through, and the second factor reflects (for the most part) just the change in assumed gearing levels (and so has an approximately neutral effect on Epic Energy).

#### 5.6.3.5 Company Taxation Liabilities

There are two main taxation issues relevant to the determination of the WACC. These are the method that is used to estimate the assumed company tax liabilities associated with the regulated activities, and the value of imputation or franking credits.

Method for Estimating Company Tax Liabilities

Epic Energy adopted one of the simple transformations to convert its estimated post tax WACC into a pre tax WACC (and thereby providing an allowance for expected company tax liabilities). Epic Energy used a variant of the "reverse transformation" method, which involves first deducting inflation from the post-tax nominal WACC, and then grossing up the post tax real WACC by one minus the statutory taxation rate. In applying this transformation,

[228] Standard and Poors "Rating Methodology for Global Power Companies", cited in Macquarie Risk Advisory Services Ltd, July 1998, Weighted Average Cost of Capital for Victorian Gas Distribution Access Arrangements.

Epic Energy assumed a corporate taxation rate of 36 percent, consistent with the taxation rate at the time of submission of the proposed Access Arrangement.

Valuation of Franking Credits

Franking credits, or imputation credits, are an allowance under the Australian taxation system that permit taxation liabilities of shareholders to be offset by the value of company tax already paid on profits from which the dividend payments are made. The approach for reflecting the value of franking credits that has emerged as standard practice is to use a market (equity) risk premium that assumes that Australia has a classical tax system (i.e. no franking credits), then to adjust the WACC or cash-flows directly to reflect the non-cash benefits associated with franking credits. The mechanism used to achieve this – the gamma term – can then be interpreted as the value of each franking credit that is created by the firm, as a proportion of the face value of that franking credit.

Epic Energy's consultants (the Brattle Group) derived a formula for the post tax WACC under which the 'gamma' term that features in the Officer version of the WACC is replaced with the following:

$$g = a \cdot q \cdot k$$

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. Values of $q$ and $k$ were derived from Australian empirical estimates of 55 percent and 80 percent respectively, and the dividend payout ratio was assumed to be 0.7. This provided an effective gamma value of 0.308.

**Submissions**

Submissions were made respect of the method that is used to estimate the assumed company tax liabilities associated with the regulated activities, and the value of imputation or franking credits.

Treasury/Office of Energy submitted that the order in which the transformation takes account of inflation and taxation has a considerable impact on the real pre-tax WACC. Submissions from WMC, Robe River Mining and Treasury/Office of Energy suggested that the corporate tax rate should be altered to reflect changes to the tax rate introduced from July 2000.

Submissions from WMC, AlintaGas,[229] North West Shelf Gas, Robe River Mining and Treasury/Office of Energy indicated that the proposed gamma value of 0.44 (which is the value being adjusted for the dividend payout ratio) is lower than the value of 0.5 that is generally used in Australian regulatory decisions, and that the correction of this value by a dividend payout ratio is without precedent in Australia.

**Considerations of the Regulator**

Approach for estimating company tax liabilities

The models drawn from finance theory for estimating the cost of capital generally deliver an estimate of the required after tax return to providers of funds. In contrast, however, the revenue benchmarks that are used to determine price controls for regulated entities reflect a pre-tax revenue stream.[230] Inevitably, therefore, regulators are constrained to make an assumption about the expected taxation liabilities of the regulated entity. If the cost of

[229] AlintaGas Submission 3.

[230] That is, regardless of what a regulator might decide or intend, the revenue that the entity earns from its regulated business will be assessable for company taxation according to the relevant statutes.

taxation were overestimated, then the target revenue would be expected to provide the regulated entity with a return that is higher than market requirements. Conversely, if the cost of taxation were underestimated, then the target revenue would be expected to provide the regulated entity with a return that is below market requirements.

An important issue for Australian regulators, and one that has generated some debate, has been whether the allowance for the cost of tax should be based upon a 'simple assumption' about the taxation system (a conversion of an after tax WACC into a pre-tax WACC using the statutory tax rate is an example of a simple assumption), or whether the allowance for tax should be based upon an explicit estimate of the cost of tax. The effective taxation rate (actual taxation liability as a proportion of regulatory profit) may differ from the statutory taxation rate for several reasons including the divergence between economic depreciation and taxation depreciation.

In turn, where a 'simple assumption' has been made, there has been lively debate about which of the possible conversion methodologies are likely to provide a better benchmark allowance for tax (this issue is discussed further below). Where explicit estimates of the cost of tax are used, there has been an issue about whether this estimate should reflect the taxation liabilities over the forthcoming regulatory period, or whether it should reflect a long-term average taxation liability.

IPART, IPARC and SAIPAR have used a simple assumption about the tax system (i.e. having utilised one or more of the available methodologies for converting an after tax WACC into a pre-tax WACC). While the ACCC and ORG have made use of similar simple assumptions in their 1998 gas decisions, more recently they have made explicit estimates of the cost of tax over the forthcoming regulatory period,[231] and the ORG has proposed[232] moving to this approach for its forthcoming review of the Victorian gas distributors.[233] The Regulator has previously used the simple approach based on the *forward transformation* method (described further below).

The Regulator has given consideration to basing its assumption about the company tax liabilities for the DBNGP regulated activities on an explicit estimate of those liabilities. However, despite the theoretical advantages associated with using these techniques, the Regulator is mindful of the complexities involved in their practical application, which will require additional and specific research before implementation. In the absence of any definitive studies demonstrating a significant bias from the use of the forward transformation, it considers this methodology to provide an appropriate basis for estimating tax liabilities for the purposes of this Draft Decision.

As noted above, once it is decided to adopt a simple transformation to obtain a benchmark for a regulated entity's taxation liabilities, there are a number of potential transformation methods that are available. In the cases where Australian regulators have used a simple transformation to derive tax benchmarks, one or both of the following two transformations have generally been employed:

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[231] For example, in ACCC, June 2000, Final Decision – Central West Pipeline Access Arrangement, and Office of the Regulator-General, September 2000, Electricity Distribution Price Determination 2001-2005 – Vol 1: Statement of Purpose and Reasons.

[232] Office of the Regulator-General, May 2001, 2003 Gas Access Arrangement Review – Consultation Paper No 1 – Issues for Consultation, p 66.

[233] More recently the ACCC has adopted an approach referred to as normalisation. The impact of normalisation is that the prices paid by customers reflects a long term average tax rate, but the economic returns of the regulated entity reflect the short term estimate of the cost of tax.

i. forward transformation, involving division of the post-tax nominal WACC by $1 - T$, where $T$ is the statutory taxation rate, and then deducting inflation (using the Fisher transformation[234]) to derive the pre-tax real WACC; and

ii. reverse transformation, involving first deducting inflation from the post-tax nominal WACC, and then grossing up the post tax real WACC by one minus the statutory taxation rate.

Epic Energy has used a transformation that is very close to the second methodology, but adjusted so that the pre tax WACC compensates investors for one year of inflation (whether this adjustment is justified is discussed separately below).

The Regulator has adopted the forward transformation methodology in this Draft Decision. The Regulator's use of the forward transformation reflects a view that the changes to the company taxation regime in Australia implemented as of 1 July 2000 are likely to narrow the gap between the statutory and effective tax rates for infrastructure firms in Australia. It is noted that this transformation provides a larger allowance for tax than the methodology proposed by Epic Energy.

Regarding the statutory rate of tax to be used in the simple transformation, Epic Energy applied the rate as applicable at the time it submitted its Access Arrangement, which was 36 percent. Since that time, the rate has changed, and the applicable rates over the nominated Access Arrangement Period (assumed to have commenced on 1 January 2000) will be 34 percent from 1 July 2000, and 30 percent 1 July 2001 onwards. For the purposes of assessing Reference Tariffs for this Draft Decision, the Regulator has used the average taxation rate over the nominated Access Arrangement Period of 1 January 2000 to 31 December 2004, which is 31.4 percent.

Regarding the adjustment to the pre-tax WACC to add on one year of inflation (as proposed by Epic Energy's consultants[235]), the Regulator notes that this adjustment is based upon the assumption that Total Revenue (or, rather, its capital-related components) will be determined in terms of prices prevailing in a base year (1999), and not escalated for inflation over the year until the first year of the Access Arrangement Period (2000).

However, it is a false assumption that the capital-related components of Total Revenue will be determined in terms of prices prevailing in a base year (1999), and not escalated for inflation over the year until the first year of the Access Arrangement Period (2000). While Total Revenue (and its components) has been established in 31 December 1999 dollars, the Regulator in re-calculating the Reference Tariff has applied six months of inflation so that the tariffs for the first year of the Access Arrangement Period will compensate for the change in the general price level from 1999. Thus, the compensation sought through the adjustment to the WACC will be provided through the way in which the tariffs are derived. Accordingly, the Regulator does not consider that the adjustment proposed by Epic Energy's consultants is necessary.

<u>Valuation of Franking Credits</u>

Franking credits, or imputation credits, are an allowance under the Australian taxation system that permit taxation liabilities of shareholders to be offset by the value of company tax already paid on profits from which the dividend payments are made. When a company pays

[234] $Real\ WACC = \frac{1 + nominal\ WACC}{1 + i} - 1$, where $i$ is the inflation rate.

[235] Refer to Appendix 2 of Access Arrangement Information, Brattle Group report on Cost of Capital, p 11.

company tax, franking credits equal to the value of the tax payments are accrued. These franking credits may then be distributed to shareholders with dividend payments. The franking credit constitutes a benefit to shareholders that face a tax liability in Australia in addition to the value of the dividend. Consequently, the distribution of franking credits will reduce a shareholder's required rate of return (in dividend payments) on the equity investment in the company. The value of franking credits is incorporated into the WACC calculation to reflect the benefits that shareholders gain from franking, and the consequent lower requirement for the Rate of Return.

The approach for reflecting the value of franking credits that has emerged as standard practice is to use a market (equity) risk premium that assumes that Australia has a classical tax system (i.e. no franking credits), then to adjust the WACC or cash-flows directly to reflect the non-cash benefits associated with franking credits. The mechanism used to achieve this – the "gamma" term in the Officer WACC (described above, page 203) – can then be interpreted as the value of each franking credit that is created by the firm, as a proportion of the face value of that franking credit.

As noted previously, Epic Energy's consultants have 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. Accordingly, to derive its 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 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.

In deriving gamma values for the purpose of setting regulated charges, in general, Australian regulators (including O*ff*GAR) have commenced with a view of the value of franking credits in the hands of investors (the $q$ term) and have reduced this to take account of the fact that all dividends may not be paid out (equivalent to a $a$ term). A further downward adjustment has not generally been made to take account of the potential for a portion of dividends to be unfranked. The Regulator has concerns about the assumed value of franking credits in the hands of investors ($q$) as well as the further downward adjustment that has been made on account of a dividend payout ratio of less than one ($a$), and the Regulator does not consider that the adjustment on account of unfranked dividends is warranted. These issues are discussed in turn below.

Regarding the assumption that is made about the value of franking credits in the hands of investors (or utilisation), it is noted that Epic Energy has relied upon empirical estimates of this value from Australian dividend drop-off studies. However, there are two factors for considering the potential range for the utilisation of franking credits may extend *higher* than assumed by Epic Energy.

- Firstly, a more recent empirical study (whose publication post-dates Epic Energy's submission of its Access Arrangement) has generated a far higher estimate of their value – of between 0.88 and 0.96. The significance of this study is that it adopted a new methodology for estimating the value of franking credits that would reduce the 'noise' associated with the estimation process.[236]

- Secondly, the criticism has been made that adopting a gamma assumption that reflects anything less than full utilisation of franking credits is inconsistent with the CAPM model being employed.[237] In particular, it has been argued that as the version of the CAPM being used is the domestic version, consistency requires an assumption that all investors are Australian, and thus can utilise franking credits fully.[238]

These two factors – when combined with the other empirical estimates of franking credit utilisation – suggest that an assumption about the rate of utilisation of franking credits that is somewhat higher than 0.55 – as assumed by Epic Energy – is more appropriate.

Regarding the assumption that is made about dividend payout ratios, it first needs to be recognised that the model that is applied by Epic Energy is only a partial analysis of Australia's personal taxation regime, and as a result, it is not clear whether or not such an adjustment may introduce a bias in one direction or the other.[239] That said, however, it has been common practice to reduce the value of franking credits to reflect the fact that even efficient firms may not distribute all of the franking credits created in any year. However, as pointed out by an independent expert in this matter, merely scaling down the value of franking credits by an average dividend payout ratio is likely to overstate the correct adjustment.[240]

Regarding the adjustment for unfranked dividends, the Regulator considers that the appropriateness of this assumption will depend upon the particular use of the estimated WACC. If, for example, a post tax WACC were used to discount a stream of cash-flows defined on a consistent basis (which would require taxation liabilities to be included in the projected cash-flows), then an adjustment to gamma to reflect the potential deferral of company tax – and hence, franking benefits – may be appropriate. This is because the assumed benefit from franking credits that is implied by the use of this form of post tax WACC would be independent of the assumed taxation liability. Thus, if the entity's actual taxation liabilities are not high enough to permit it to pay fully-franked dividends, then the benefits of dividend imputation would be overstated.

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[236] Walker, S and G Partington (1999), 'The Value of Dividends: Evidence from Cum-Dividend Trading in the Ex-Dividend Period', *Accounting and Finance*, Vol 39, pages 275-296. The difference in this study was that its estimate of the value of franking credits was based on the difference in the price of shares that were trading simultaneously cum-dividend and ex-dividend. The previous studies had measured the drop-off in the share price between two periods of time (namely cum-dividend and ex dividend periods). The simultaneous measurement of cum-dividend and ex-dividend share prices implies that many of the other factors that affect share prices are removed automatically from the analysis.

[237] Lally, M (2000), 'The Cost of Equity Capital and its Estimation', *McGraw Hill Series in Advanced Finance*, Vol 3, pp 10-11.

[238] An alternative approach would be to use an international version of the CAPM, and thus assume that foreign investors determined the equilibrium cost of capital. The main implications of this model would be that 'gamma' would be zero, but that the market risk premium and possibly the proxy beta values would be lower. The ORG addressed this issue in some detail and concluded that the domestic CAPM was likely to predict a higher cost of capital than would the international CAPM: ORG, *Electricity Distribution Price Determination 2001-2005*, Vol 1, p 317.

[239] The model employed by Epic Energy (and similarly with the Officer post tax WACC) is only partial because it does not consider capital gains tax issues.

[240] Davis, K., 1998, The Weighted Average Cost of Capital for the Gas Industry, report prepared for the Australian Competition and Consumer Commission and Office of the Regulator General, p 13 and Appendix 1.

However, in the matter at hand, both the assumed value of franking credits and the assumed taxation liabilities are captured in the WACC. Thus, to the extent that a low effective tax rate were assumed, the implied value of franking credits would fall in line with the assumed tax payments automatically, and no additional adjustment to the gamma term would be necessary. Moreover, in the case of the DBNGP, the Regulator has applied the forward transformation to estimate the benchmark taxation liabilities for its regulated activities. This assumption actually implies that the effective tax rate (defined in terms of accounting income) is likely to exceed that statutory tax rate, implying an excess (rather than inadequacy) of franking credits. Thus, in any case, an assumption that the DBNGP would not pay sufficient company tax to pay fully franked dividends is inconsistent with the assumption that has been made about its taxation liabilities (as implied by the use of the forward transformation).

For these reasons, the Regulator considers that a downward adjustment to the gamma value to reflect an assumed proportion of unfranked dividends is unwarranted.

The value for franking credits that has been assumed in other regulatory decisions in Australia is shown below.

**Gamma Assumptions Adopted by Australian Regulators**

| Regulatory Decision | Gamma Assumption |
|---|---|
| ORG Final Decision on Victorian Gas Distribution (October 1998) | 0.50 |
| ACCC Final Decision on Victorian Gas Transmission (October 1998) | 0.50 |
| IPART Final Decision on Great Southern Network (March 1999) | 0.30 – 0.50 |
| IPART Final Decision on Albury Gas Company (December 1999) | 0.30 – 0.50 |
| IPART Final Decision on AGL Gas Networks Limited (July 2000) | 0.3 – 0.5 |
| IPART NSW Electricity Distributors / Transmission Draft Decision (July 1999) | 0.30 – 0.50 |
| ACCC Final Decision on Central West Pipeline (June 2000) | 0.50 |
| ACCC Draft Decision on Moomba to Sydney Pipeline System (June 2000) | 0.50 |
| Independent Gas Pipelines Access Regulator (WA) Final Decision on the Mid-West and South-West Gas Distribution Systems (June 2000) | 0.50 |
| Independent Gas Pipelines Access Regulator (WA) Draft Decision on the Tubridigi Pipeline (August 2000) | 0.50 |
| Independent Gas Pipelines Access Regulator (WA) Final Decision on the Parmelia Pipeline (October 2000) | 0.50 |
| Independent Gas Pipelines Access Regulator (WA) Final Decision on the Goldfields Gas Pipeline (April 2001) | 0.5 |
| ACCC TransGrid Draft Decision (May 1999) | 0.50 |
| ACCC Telstra's Originating and Terminating Access Undertaking (June 1999) | 0.50 |

While the available evidence discussed above suggests that the values for "gamma" that have been adopted by Australian regulators are towards the lower end of the reasonable range, the Regulator considers it appropriate to adopt a conservative view and adopt a gamma value of 0.5 for the purpose of estimating the cost of capital associated with the regulated activities of the DBNGP.

#### 5.6.3.6 WACC Estimate

A comparison of values of input variables to the WACC calculation used by Epic Energy with values considered reasonable by the Regulator is provided as follows.

**Proposed and revised CAPM parameter values for estimation of the rate of return**

| Parameter | Parameter symbol | Value used by the Epic Energy | Value proposed by the Regulator |
|---|---|---|---|
| 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 | $g$ | 30.8% [241] | 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% |

The revised WACC estimates for the DBNGP are as follows.

**Revised WACC for the DBNGP**

| Estimated WACC | Nominal | Real |
|---|---|---|
| Post-Tax (Officer) | 7.23% | 4.64% |
| Pre-tax (forward transformation of Officer WACC) | 10.54% | 7.87% |

The Regulator has adopted a real pre-tax WACC of 7.85 percent[242] for the purposes of assessing Epic Energy's proposed Reference Tariff.

The returns to equity that are implied by this WACC estimate are as follows.

**Returns on equity implicit in the revised pre-tax WACC**

| Returns on Equity | Nominal | Real |
|---|---|---|
| Post-Tax | 13.16% | 10.42% |
| Pre-tax | 15.61% | 12.81% |

241 Derived from Epic Energy's stated franking credit (gamma) value of 0.44 scaled by a dividend payout ratio of 0.7 to give an effective dividend credit value of 0.308.

242 The Regulator has rounded this figure to the nearest five basis points.

The Regulator's estimate of the cost of capital associated with regulated activities of the DBNGP is 7.85 percent (pre-tax, real), based on estimates of the risk free rate and inflation as of 31 May 2001, is at the higher end of the range of Rates of Return that have been approved for comparable regulated pipelines in Australia. While the Regulator has used different assumptions for the various inputs to those adopted by Epic Energy, it should be noted the Regulator's and Epic Energy's estimates of the cost of capital associated with the DBNGP are very similar once account is taken of the changes in interest rates and the statutory tax rate that have occurred since Epic Energy submitted its Access Arrangement. That is, had the Regulator adopted the interest rates and tax rate that prevailed at the time of Epic Energy's submission, it would have estimated a WACC comparable to that calculated by Epic Energy.

The following amendment is required before the Access Arrangement will be approved.

| |
|---|
| Amendment 57<br><br>The Access Arrangement and Access Arrangement Information should be amended to reflect a pre-tax real rate of return of 7.85 percent. |

## 5.7 DEPRECIATION SCHEDULE

### 5.7.1 Access Code Requirements

Sections 8.32 to 8.34 of the Code specify rules for depreciation of assets that form part of the Capital Base, for the purposes of determining a Reference Tariff.

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 (the Depreciation Schedule).

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 covered pipeline 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 covered pipeline 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).

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 Covered Pipeline is:

(a) for an asset that was in existence at the commencement of the Access Arrangement Period, the difference between the value of that asset in the Capital Base at the commencement of the Access Arrangement Period and the value of that asset that is reflected in the Residual Value; 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 Covered Pipeline should reflect notional depreciation that meets the principles of section 8.33; and

(d) the Reference Tariff should change over the Access Arrangement Period 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 towards the end of the Access Arrangement Period, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the pipeline has been sized accordingly).

### 5.7.2 Access Arrangement Proposal

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

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.

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.

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 |

In the calculation of depreciation schedules, Capital Expenditure on new facilities is added to the physical asset account and subsequently depreciated by the annuity method over the assumed economic lives for relevant asset classes.

With Epic Energy's proposed value of the Initial Capital Base and the proposed Reference Tariff, the expected revenue from the DBNGP over the Access Arrangement Period is insufficient to cover the annuity charges. Epic Energy has proposed treating the shortfall in capital charges by way of "economic depreciation".

Economic depreciation for a 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.[243] Where economic depreciation is negative (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.

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

[243] 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 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.)

**Epic Energy Regulatory Asset Accounting (nominal $million, year ending 31 December)**[244]

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Beginning of year balances | | | | | |
| Physical asset account …(1) | 2,570.37 | 2,596.50 | 2,606.44 | 2,617.30 | 2,624.65 |
| Deferred recovery account …(2) | 0.00 | 106.32 | 226.55 | 360.39 | 504.73 |
| Capital Base (1+2) …(3) | 2,570.37 | 2,702.81 | 2,832.99 | 2,977.69 | 3,129.38 |
| Forecast revenue …(4) | 221.38 | 224.53 | 229.04 | 236.22 | 242.71 |
| Return on Capital Base …(5) | 288.20 | 303.053 | 317.65 | 333.87 | 350.88 |
| 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) | -106.32 | -120.23 | -133.84 | -144.34 | -155.62 |
| Capital Expenditure (9) | 26.51 | 10.38 | 11.35 | 7.90 | 3.16 |
| End of year balance | | | | | |
| Physical asset account (3+9) …(10) | 2,596.50 | 2,606.44 | 2,617.30 | 2,624.65 | 2,627.20 |
| Deferred recovery account $\lvert\Sigma(8)\rvert$ …(11) | 106.32 | 226.55 | 360.39 | 504.73 | 660.35 |

### 5.7.3 Submissions from Interested Parties

#### 5.7.3.1 Overview

Views and concerns on the proposed Depreciation Schedule were expressed in submissions in relation to:

- assumptions as to asset lives;
- the annuity method of depreciation; and
- the proposal for economic depreciation and deferred recovery of capital costs.

The Regulator's responses to submissions in respect of these matters are documented below. There was a large degree of commonality in the submissions in respect of each of the above matters and the Regulator has therefore summarised the content of submissions rather than providing paraphrased extracts from individual submissions.

#### 5.7.3.2 Assumptions as to Asset Lives

Western Power and AlintaGas[245] submitted that the asset lives assumed for the purposes of the Depreciation Schedule are unsubstantiated. AlintaGas submitted that the assumed asset lives are excessively long and inconsistent with a previous information memorandum from the manager of the Australian Infrastructure Fund (a part of owner of the DBNGP) that the

[244] Epic Energy response to Information Request 6, 24 November 2000.
[245] Western Power Submission 3 and AlintaGas Submission 3.

expected economic life of the pipeline is expected to be 65 years. AlintaGas also submitted that the assumed asset lives were inconsistent with asset lives stated in justification for forecast Capital Expenditure.

On the basis of technical advice, the Regulator is of the view that the asset lives assumed by Epic Energy for depreciation purposes (100 years for pipeline assets, 57 years for compression assets, and 71 years for metering assets and 50 years for other assets) are excessive in comparison with common assumptions for gas transmission pipelines. In the absence of justification for the assumptions made in the case of the DBNGP, the Regulator considers that the Reference Tariff should be determined on the basis of assumed asset lives that are consistent with common industry assumptions, being 70 years for pipelines, 30 years for compression assets, 50 years for metering assets and 30 years for other assets.

#### 5.7.3.3 Annuity Methodology of Depreciation

WMC, AlintaGas[246] and Worsley Alumina raised concerns in submissions as to the appropriateness of the annuity method of depreciation used by Epic Energy and suggested that a straight-line method of depreciation should be used. WMC indicated that the straight-line method of depreciation has advantages of simplicity and ease of understanding, as well as being consistent with past regulatory practice. AlintaGas questioned the appropriateness of annuity depreciation in a situation of little forecast increase in gas throughput.

Western Power[247] and Treasury/Office of Energy expressed the view that there is inadequate detail in the proposed Access Arrangement to identify how the depreciation schedule has been derived and to gain some idea of the long-term depreciation of assets.

As has been noted in submissions, regulatory decisions on Access Arrangements under the Code have to date generally accepted or imposed the determination of asset depreciation using a straight-line calculation methodology. In the absence of new Capital Expenditure, a straight-line depreciation methodology would involve a constant annual return of capital (in real terms) over an assumed life of assets. Epic Energy has proposed determination of asset depreciation by the annuity method. This involves determination of a depreciation schedule such that, for a given Initial Capital Base value and no new Capital Expenditure, the sum of return on capital and depreciation is constant over the assumed life of assets. An effect of the annuity method is that the return of capital (depreciation) increases over the life of the assets, with most return of capital occurring in the latter part of the life of the asset. This is conceptually similar to a typical repayment scheme for a home mortgage whereby a periodic payment comprises an interest (capital charge) component and a principal (return of capital) component. Subject to a constant interest rate (cost of capital) the periodic payment remains constant over the course of the loan, although over time the interest component of annual repayments decreases and the principal component increases, with most of the principal being repaid in the latter part of the loan period.

An annuity method of depreciation is a well-recognised form of capital accounting and cannot be dismissed from consideration on the basis of greater complexity than a straight-line methodology. Rather, consideration must be given to whether an annuity methodology is consistent with the requirements of the Code.

[246] AlintaGas Submission 3.

[247] Western Power Submission 3.

The provisions of the Code relating to depreciation of the Capital Base of a pipeline specify only general principles for a Depreciation Schedule (section 8.33) and, subject to these principles being satisfied, do not impose any requirement for utilisation of any particular depreciation methodology. The principles set out in section 8.33 of the Code are that a Depreciation Schedule should be designed:

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

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

(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 covered pipeline 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).

The effect of an annuity method of depreciation is to “back-end” the depreciation schedule so that most recovery of capital occurs in the latter part of asset lives. AlintaGas and Worsley Alumina have submitted that, in the absence of any forecast market growth by Epic Energy, this is contrary to the principle of section 8.33(a) of the Code. Section 8.33(a) indicates that it may be appropriate for a depreciation Schedule to “involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the Reference Tariffs has assumed a significant market growth and the Pipeline has been sized accordingly.” The Regulator is of the view that the principle established by section 8.33(a) of the Code is concerned with the changes in the Reference Tariff over time and not, necessarily, changes in the return of capital over time. An annuity method of depreciation would, all other things being equal, result in a tariff outcome where the tariff would remain constant for constant throughput, or would decrease in proportion to any increases in throughput (as constant capital costs are distributed over greater units of throughput). An annuity method of depreciation is therefore not inconsistent with the principle of section 8.33(a) of the Code. Further, the Regulator is of the view that, subject to details of application, an annuity method of depreciation is not inconsistent with other principles set out in section 8.33.

Aside from the specific requirements of the Code, an annuity method of depreciation has the advantage of levelising capital costs (the sum of return on capital and return of capital) over the life of the assets and mimicking cost allocation and pricing in competitive markets where prices tend to be independent of the age of fixed assets.[248] Against this advantage are potential disadvantages to the Service Provider arising from recovery of capital predominantly in the latter part of the life of the assets and consequent risks of stranding of asset value. However, where a Service Provider proposes an annuity method of depreciation, the Regulator considers this risk to be a matter largely for consideration of the Service Provider.

The Regulator is therefore of the view that the proposed annuity method of depreciation is acceptable for the determination of Reference Tariffs.

[248] ACCC, May 1999. Draft Statement of Principles for the Regulation of Transmission Revenues, p 61.

#### 5.7.3.4 Deferred Depreciation

Several submissions to the Regulator expressed concerns with Epic Energy's proposed "economic depreciation".

Under Epic Energy's proposal, economic depreciation is defined as forecast actual revenue minus the cost-based target revenue (i.e. Total Revenue) determined in accordance with the guidelines of section 8 of the Code. The value of economic depreciation is credited to a deferred recovery account, the balance of which forms part of the Capital Base of the DBNGP. Over the Access Arrangement Period, Epic Energy has forecast the value of economic depreciation to be negative, implying an increasing balance of the deferred recovery account and an increasing value of the Capital Base. The shortfall of forecast revenue against target revenue arises from Epic Energy's proposed cap on the Reference Tariff that is less than the Reference Tariff that would otherwise be derived from a cost of service model in accordance with section 8 of the Code.

Both Epic Energy[249] and several persons making submissions[250] have indicated that the proposed economic depreciation for the DBNGP is similar to depreciation arrangements approved by the ACCC for the Access Arrangement for the Central West Pipeline[251] and approvals under the Victorian Access Code for the Mildura natural gas distribution system[252] and East Gippsland natural gas distribution system.[253] The ACCC and ORG accepted the use of economic depreciation and deferred recovery for these pipelines for reasons of these being new pipelines with no established markets and being utilised at substantially less than capacity, and for which it is therefore reasonable that the return of capital be deferred to future periods when the size of the markets for gas transmission/distribution have increased. The view is expressed in submissions on the proposed DBNGP Access Arrangement that the DBNGP, in contrast, is a "mature" pipeline that is being operated at close to capacity and for which the same argument for deferred depreciation does not apply.

Concerns are noted in submissions that the proposed economic depreciation for the DBNGP is being used as a means of accommodating an unreasonably high valuation of the Initial Capital Base and/or enabling Epic Energy to maintain higher tariffs than otherwise may have been the case and capture the benefit of future productivity gains and reductions in operating costs.[254] Submissions have also questioned whether economic depreciation as proposed by Epic Energy conforms to the intent of the Code,[255] including compliance with sections 8.9 and 8.16 in relation to changes in the value of the Capital Base.

The Regulator has noted that the previous regulatory decisions that have approved the use of economic depreciation and deferred recovery of capital costs have occurred for pipelines where the Capital Base is determined on the basis of an optimised replacement cost of assets

[249] Epic Energy Submission 3.

[250] Submissions from CMS, AlintaGas (Submissions 3, 4), Western Power (Submission 3), Wesfarmers.

[251] ACCC, June 2000. Final Decision – Central West Pipeline Access Arrangement.

[252] Office of the Regulator General, Victoria, June 1999. Access Arrangement for Envestra Limited in Respect of the Proposed Mildura Natural Gas Distribution System Final Decision.

[253] Office of the Regulator General, Victoria, May 1999. Access Arrangement for Eastcoast Gas Pty Ltd in Respect of the Proposed East Gippsland Natural Gas Distribution System Final Decision.

[254] Submissions from AGL, AlintaGas (Submissions 3, 4), Worsley Alumina, WMC, Western Power (Submission 3), Treasury/Office of Energy, Mark Neville MLC.

[255] Submissions from Western Power (Submission 3), AlintaGas (Submission 3), Robe River Iron Associates, Treasury/Office of Energy, Chamber of Minerals and Energy, Apache Energy Limited.

(Central West Pipeline) or the actual cost of construction of assets (Mildura and East Gippsland distribution systems). In these cases economic depreciation and deferred recovery were considered by the relevant regulators to provide a mechanism whereby the Service Providers may recover prudent and efficient capital costs, while providing for a reasonable tariff in the initial part of the pipeline lives that will enable the establishment and growth of gas markets. The Regulator concurs with the views expressed in submissions that a similar situation does not exist for the DBNGP for the pipeline assets are being used at close to capacity and for which markets for gas transmission are well established. As such, the regulatory decisions for the Central West Pipeline and Mildura and East Gippsland Distribution Systems are considered by the Regulator to not justify, by dint of precedent, acceptance of Epic Energy's proposal for economic depreciation involving deferred recovery of capital.

Deferred recovery of capital costs would be in the interests of Epic Energy if it allowed for a higher valuation of the Capital Base for a pipeline while maintaining a relatively low Reference Tariff at the current time. However, a higher value of the Initial Capital Base accompanied by deferred recovery gives rise to a risk for Users that, if expectations of market growth are not realised, the Reference Tariff may increase as a result of higher capital costs that would otherwise have been the case. To approve a proposal for economic depreciation and deferred recovery of capital for the DBNGP Access Arrangement, the Regulator would need to be satisfied that a higher value of the Initial Capital Base accompanied by a mechanism of deferred recovery would be consistent with the long-term interests of both the Service Provider and Users. It would need to be demonstrated that such an approach would provide for the recovery of efficient and prudent capital costs of providing transmission services (as measured by an actual historical cost, optimised replacement cost or DORC value as appropriate in the circumstances) and that there is a sufficient prospect of market growth such that, despite the risks of higher tariffs, deferred recovery could be regarded as in the long term interests of Users. The Regulator is of the view that Epic Energy has not put forward a case that meets these requirements.

### 5.7.4 Additional Considerations of the Regulator

In responding to submissions made on the proposed Access Arrangement in respect of the depreciation Schedule, the Regulator concluded 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;
- the annuity method of depreciation is consistent with the principles set out in the Code for a Depreciation Schedule and is therefore acceptable for the purposes of setting the Reference Tariff; and
- for the DBNGP at present, there is no reasonable justification for economic depreciation and deferred recovery of capital costs so as to accommodate a higher value of the Initial Capital Base.

The Regulator has revised the Depreciation Schedule proposed by Epic Energy to reflect the Regulator's determinations on the Initial Capital Base and Capital Expenditure, and reasonable assumptions as to asset lives. For the purposes of this Draft Decision, the Regulator has considered both the annuity method of depreciation as proposed by Epic Energy, and the straight-line method. The revised Depreciation Schedules under each of these methodologies are as follows.

**Revised Depreciation Schedule (annuity method, 1999 $million, year ending 31 December)**

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Pipeline Assets | 1.30 | 1.41 | 1.52 | 1.64 | 1.76 |
| Compression Assets | 4.29 | 4.64 | 5.00 | 5.48 | 5.91 |
| Metering Assets | 0.07 | 0.07 | 0.08 | 0.08 | 0.09 |
| Other Assets | 1.12 | 1.29 | 1.44 | 1.60 | 1.77 |
| **Total** | **6.82** | **7.41** | **8.08** | **8.80** | **9.53** |

**Revised Depreciation Schedule (straight-line method, 1999 $million, year ending 31 December)**

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Pipeline Assets | 18.42 | 18.42 | 18.43 | 18.43 | 18.44 |
| Compression Assets | 8.98 | 9.03 | 9.29 | 9.53 | 9.63 |
| Metering Assets | 0.36 | 0.36 | 0.36 | 0.37 | 0.37 |
| Other Assets | 2.25 | 2.55 | 2.85 | 3.19 | 3.47 |
| **Total** | **30.00** | **30.36** | **30.92** | **31.51** | **31.90** |

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 58

The proposed Access Arrangement and Access Arrangement Information should be amended to reflect a Depreciation Schedule determined by either annuity or straight-line depreciation methodologies as follows (31 December 1999 $million).

| **Year ending 31 December** | **2000** | **2001** | **2002** | **2003** | **2004** |
|---|---|---|---|---|---|
| Annuity Depreciation | 6.92 | 7.48 | 8.10 | 8.77 | 9.45 |
| Straight-Line Depreciation | 30.00 | 30.36 | 30.92 | 31.51 | 31.90 |

Given the revisions required to be made to the proposed Access Arrangement, the Regulator assumes that Epic Energy will wish to base tariffs on straight-line depreciation. For this reason, the Regulator has based the remainder of the assessment of Reference Tariffs on straight-line depreciation of assets as indicated above.

## 5.8 TOTAL REVENUE

### 5.8.1 Access Code Requirements

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 (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.

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 discretion.

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.

### 5.8.2 Access Arrangement Proposal

Epic Energy has calculated 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** |

### 5.8.3 Submissions from Interested Parties

Submissions on the proposed Access Arrangement in regard to the determination of Total Revenue are indicated and responded to as follows.

- Western Power Submission 3

  The Total Revenue is said to be calculated using the 'cost of service' method described in the National Access Code (Cl 8.4). This requires that the Total Revenue equal the costs derived for all services, not just the Reference Service. However this is difficult to reconcile based on Epic Energy's assumption that all Shippers will be using the Reference Service. In fact, in the initial years, Reference Service Shippers will occupy at most a negligible proportion of DBNGP capacity. For this reason alone, the Total Revenue does not appear to have been calculated in accord with the Code.

  The Total Revenue to be derived from services is not defined but may be deduced as arising from:

  – revenue to be derived from the Reference Service, which initially will be zero or very small

  – revenue to be derived from Prior Contracts, and which are defined as Non-Reference Services, which will be the major proportion of revenue

  – revenue derived from other Non-Reference Services, which are rebatable, and

  – revenue derived from surcharges, fees and other payments.

> The imputed Total Revenue has been calculated on an assumption that all grandfathered contracts are Reference Service contracts, when in fact revenue will almost exclusively be derived from Prior Contracts and their existing tariffs. This does not conform to the Code.
>
> The derivation of the 'cost of service' for the Reference Service proceeds on the basis that the Prior Contracts (being Non-Reference Services) are in fact Reference Services. If it were otherwise there would be effectively no costs associated with the Reference Service, as there are no projected Reference Service Shippers in the Access Arrangement Period.
>
> The return on the Capital Base appears to have been miscalculated as the application of WACC as determined by the Brattle report adjusted to a nominal base gives lower required returns than shown in Table 2.2: Forecast Total Costs of Providing Services, page 9, Access Arrangement Information.

The submission from Western Power indicates some confusion as to the use in the Code of the term "Total Revenue". Although Total Revenue is defined in section 8.2 of the Code as "the revenue to be generated from the sales (or forecast sales) of all services over the Access Arrangement Period", the requirements of the Code in respect of the determination for Total Revenue (section 8.4) give the term the meaning of a target revenue or total cost. The term is not used in the sense of being a forecast of total receipts from the sale of services.

Under the cost of service methodology used by Epic Energy to derive the Total Revenue (consistent with the requirements of section 8.4 of the Code), Total Revenue is equal to the total cost of providing all services determined as the sum of a return on the Capital Base, depreciation of the Capital Base and Non-Capital Costs. Whether these costs arise in the delivery of Reference Services or other services is irrelevant.

Western Power has also indicated concern with Epic Energy's methodology for calculation of the return on capital. Epic Energy's methodology involved multiplying the nominal value of the Capital Base by the nominal pre-tax WACC (11.2 percent). With addition of other cost components, a Total Revenue requirement would be generated for each year, also in nominal terms. In a standard approach to calculation of a levelised tariff for the Access Arrangement Period a present value of revenue would be calculated using a discount rate equal to the nominal WACC. This tariff would then be annually escalated for inflation. The Regulator is satisfied that the approach taken by Epic Energy is consistent with conventional financial modelling practice and does not lead to double-counting of inflation effects.

- Treasury/Office of Energy

> It is suggested that the "tariff path" proposed by Epic Energy as part of the DBNGP sale process, and consequently under its Access Arrangement, would have involved a long term NPV calculation based on certain assumptions at the time of purchase. It is considered that the Regulator should request that Epic Energy now determine its proposed "tariff path" using an alternative long term NPV method based on realistic current parameters instead of the "cost of service" approach currently proposed. This would enable the Regulator, and the users of the pipeline, to fully understand the various assumptions underlying the reference tariff and to determine the adequacy of the "tariff path" in terms of providing a reasonable rate of return to Epic Energy.

Under provisions of sections 8.4 and 8.5 of the Code, the methodology used to determine Total Revenue is at the discretion of the Service Provider subject to the methodology being one of "cost of service", "internal rate of return" and "net present value", or any alternative methodology being shown to be consistent with one of these. The Regulator notes that with the same assumptions as to the Capital Base, Rate of Return, Depreciation Schedule and Non-Capital Costs, the same Total Revenue would be derived from any of the methodologies allowed for by the Code.

Further, the Code only requires that Total Revenue be determined on the basis of cost assumptions over the Access Arrangement Period.

In view of the provisions of the Code in respect of methodology for determination of Total Revenue, the Regulator cannot require a Service Provider to use any particular methodology, or to indicate Total Revenue requirements beyond the Access Arrangement Period.

Notwithstanding this, however, the Total Revenue requirement for the DBNGP and the tariff path for the Access Arrangement Period are based on assumptions by Epic Energy as to Capital Expenditure and depreciation. Description of these assumptions and the manner in which they affect Total Revenue and tariffs for the Access Arrangement Period can reasonably be considered as necessary to understand the derivation of the Reference Tariff and thus be required to be included in the Access Arrangement Information. The Regulator considers that Epic Energy has met this requirement in information provided in the Access Arrangement (section 7, Reference Tariff Policy), the Access Arrangement Information and the additional document "Proposed Regulatory Model for the Dampier to Bunbury Natural Gas Pipeline" that was submitted to the Regulator on 28 February 2000 and subsequently made available via O*ff*GAR's web site.

In assessment of the proposed Total Revenue for the DBNGP, the Regulator considered the appropriateness of the various assumptions made by Epic Energy in respect of Capital Expenditure and depreciation that have an impact on tariffs beyond the Access Arrangement Period. The Regulator's determinations on Capital Expenditure and depreciation are described in sections 5.4 and 5.7 of this Draft Decision, with consequences for Total Revenue as described in section 5.8.4, below.

### 5.8.4 Additional Considerations of the Regulator

The Total Revenue for the DBNGP indicated by Epic Energy in Table 2.2 of the Access Arrangement Information and reproduced in section 5.8.2 makes 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.

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 "building-block" 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** |

On the basis of analysis of the information provided by Epic Energy, the Regulator considers that the Total Revenue proposed by Epic Energy needs to be revised to reflect:

- revisions to capital costs arising from the Regulator's determinations on the Initial Capital Base, Capital Expenditure, Rate of Return and Depreciation Schedule as described in sections 5.3, 5.4, 5.6 and 5.7 of this Draft Decision; and
- revisions to Non-Capital Costs as described in section 5.5 of this Draft Decision.

The revised Total Revenue, which excludes any allowance for deferred recovery of capital costs, is as follows, assuming straight-line depreciation of assets.

**Revised Total Revenue (straight-line depreciation, 1999 $million, year ending 31 December)**

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| Return on Capital | | | | | |
| Pipeline | 78.79 | 77.37 | 75.95 | 74.51 | 73.09 |
| Compressor stations | 13.20 | 12.57 | 12.20 | 11.82 | 11.22 |
| Metering assets | 1.08 | 1.05 | 1.03 | 1.00 | 0.98 |
| Other assets | 3.78 | 4.00 | 4.19 | 4.42 | 4.54 |
| Depreciation | | | | | |
| Pipeline assets | 18.42 | 18.42 | 18.43 | 18.43 | 18.44 |
| Compressor stations | 8.98 | 9.03 | 9.29 | 9.53 | 9.63 |
| Metering assets | 0.36 | 0.36 | 0.36 | 0.37 | 0.37 |
| Other assets | 2.25 | 2.55 | 2.85 | 3.19 | 3.47 |
| Non-Capital Costs | | | | | |
| Pipeline maintenance | 10.63 | 10.32 | 10.34 | 10.38 | 10.40 |
| Compressor maintenance | 3.54 | 3.55 | 5.41 | 5.79 | 5.10 |
| Compressor fuel | 12.45 | 13.07 | 13.30 | 13.92 | 14.22 |
| Other costs | 11.79 | 12.69 | 12.83 | 12.06 | 11.97 |
| **Total** | **165.26** | **164.99** | **166.18** | **165.40** | **163.42** |

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 59:

The proposed Access Arrangement and Access Arrangement Information should be amended to reflect a Total Revenue as follows for a straight-line depreciation methodology (31 December 1999 $million).

| **Year ending 31 December** | **2000** | **2001** | **2002** | **2003** | **2004** |
|---|---|---|---|---|---|
| Total Revenue (straight-line depreciation) | 165.26 | 164.99 | 166.18 | 165.40 | 163.42 |

## 5.9 COST/REVENUE ALLOCATION AND REFERENCE TARIFF

### 5.9.1 Access Code Requirements

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.

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.

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.

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 8.10 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.

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.

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.

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.

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).

The effect of (b), above, 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.

In this situation, 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.

### 5.9.2 Access Arrangement Proposal

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

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. The derivation of the Reference Tariff and the Access Arrangement proposal in respect of Rebatable Services are described below.

**Reference Tariff**

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.

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.<br>Depreciation of pipeline asset value by pipeline zone.<br>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.<br>Depreciation of compressor station asset value for each compressor station.<br>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.<br>Depreciation of asset value for “other” assets.<br>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.<br>Depreciation of asset value for metering assets at Delivery Points. | Fixed charge for each Delivery Point. |

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 accordingly 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.

On the basis of the Total Revenue derived by Epic Energy for 2000, the Reference Tariff charges would be as follows.[256]

**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 | Zone 3 | Zone 4 | Zone 4a | Zone 5 | Zone 6 | Zone 7 | Zone 8 | Zone 9 | Zone 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.0181 | 0.2272 | 0.3236 | 0.4185 | 0.5137 | 15.7987 | 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 and 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)**

Delivery point located between:

| Dampier & Zone 1a | Zone 1a & CS2 | CS2 & CS3 | CS3 and 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 |

[256] 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 |

For gas transmission with a 100 percent load factor, Epic Energy has indicated that the total of charges excluding the Delivery Point Charge would amount to $1.41/GJ for delivery to from Zone 1a to Zone 9, and $1.62/GJ for delivery from Zone 1a to Zone 10. The Delivery Point Charge would add, on average, a further 6.5 cents per gigajoule to the Reference Tariff, based on current throughput to Delivery Points, although this varies between 0.3 cents and 27.3 cents per gigajoule.

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.

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.

The adjusted charges of the 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 and 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 and 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 Reve nue ($/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 |

## Rebatable Services

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.

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.[257] 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:
>
> DR = RR – [(TRFS – RFS) + (FPR – PR) + r x Q]
>
> = RR – (TRFS – RFS + r x Q) – FPR + PR
>
> = (RR + PR) – (TR + FPR)
>
> 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:
>
> $a_1$ x (FSC – PAC) x $C_1$ + $a_2$ x (FSV – PAV) x $C_2$ – RFS + r x 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.

[257] Epic Energy, 31 January 2001, Dampier to Bunbury Natural Gas Pipeline, Proposed Access Arrangement Under the National Access Code, Additional Paper 6: Rebateable Revenue.

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 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;

$C_2$ = 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 compressor 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 |

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;[258] 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.

[258] For clarification, additions of positive sums to the deferred recovery account act to reduce the “negative balance” of the account.

### 5.9.3 Submissions from Interested Parties

#### 5.9.3.1 Overview of Submissions

Public submissions on the proposed Access Arrangement addressed the following issues in relation to cost allocation and the Reference Tariff:

- 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 from 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.

Many of the submissions on cost allocation and the Reference Tariff made comments in relation to criteria of efficiency and equity.

The submissions in respect of each of these issues are summarised and responded to below.

Before summarising and responding to submissions, however, the Regulator notes that many of the submissions on cost allocation and the Reference Tariff made comments in relation to criteria of efficiency and equity. The Regulator therefore considers that a general discussion of criteria of efficiency and equity is useful prior to responding to submissions.

The economic efficiency of a cost allocation and service tariff relates to the extent to which the tariffs encourage efficient outcomes. An efficient outcome occurs where it is impossible to re-allocate resources between uses, or to change production techniques, or to trade goods or services between consumers in a way that would make consumers *as a group* better off. An efficient tariff for a gas transmission service is one that will encourage a level of use of the service by each User such that the Users (and end users of gas) could not, as a group, be made better off by changing their levels of use.

In purely competitive markets, the pricing rule that would lead to efficient prices is that of *price = marginal cost*. That is, the prices should be set to the avoidable cost of providing goods or services.

In an industry such as gas transmission that is characterised by a high level of sunk investment and fixed costs, a pricing rule that would result in consumers paying only the marginal cost or avoidable cost of producing the service would result in efficient consumption decisions in the short term, but would result in producers of the service not being able to recover the long run costs of service provision. This would result in a situation of long-term inefficiency where too few resources are devoted to production of the service. Long term efficiency can, however, be achieved by modified pricing rules as follows:

- A consumer should pay a price less than or equal to the stand-alone cost of providing the service to that consumer individually.

- A consumer should pay a price that is equal to or higher than the avoidable cost of providing the service to that consumer, so that each consumer pays a price that covers the avoidable costs of service provision and generally makes some contribution to fixed costs.
- A consumer pays a price that results in the level of consumption of the service by that consumer resembling as close as possible the level of consumption that would arise if that consumer paid a price equal to only the avoidable cost of service provision.

The first two of these criteria form upper and lower bounds for efficient prices.

The practical rationale for the upper bound is that if individual consumers were charged more than the cost of duplicating the service on a stand-alone basis, then this might induce the consumers to by-pass the existing transmission system. If this resulted in costs being borne that exceed the avoidable cost of serving the consumer through the existing system, then this would result in society incurring costs (for by-pass) that are unnecessary and thus wasteful. As consumers as a whole generally bear all of the costs incurred in providing services, this would increase the total costs they would bear (i.e. costs of the incumbent Service Provider and of the system by-pass), and so increase average prices from what they otherwise would have been.

The practical rationale for the lower bound is that if customers pay less than the avoidable cost of providing their service, then:

- the customer may choose to take the service even though they place a low value on it; or
- the customer might choose to take a service from the existing pipeline system, even though there might be lower-cost options to meet the gas or energy needs of the consumer.

Either way, if an individual customer pays less than the avoidable cost and therefore causes more (forward-looking) costs to be incurred by the Service Provider than are paid for through the tariff, then they generate more costs than revenue for the Service Provider, and so cause tariffs for all other customers to be higher as a result.

On the basis of these considerations of efficiency, a tariff structure should comply with the following broad criteria:

- All Users should pay at least the avoidable cost of the gas transmission service they receive.
- For the last unit of gas transported for a User, the marginal charge to that User should be equal or close to the marginal or incremental cost of transporting that last unit of gas.

A cost allocation and resultant tariff structure also has efficiency implications beyond Users of the transmission pipeline, in particular for end users of gas that ultimately bear the cost of transmission charges as a component of the final price of gas. The structure of transmission tariffs will affect the marginal cost of incremental units of gas delivered to an end user, and consequently decisions of that end user as to the use of gas. An efficient structure of a Reference Tariff for transmission should be consistent with, or at least not contrary to, price signals to end users of gas that motivate efficient gas use. In general this would require that the magnitude and structure of a transmission tariff reflect efficiency considerations as described above.

There are also criteria of equity against which a tariff structure can be assessed. A tariff structure recovers revenue from Users of a service. An equity criterion would require that the revenue recovered from a User be at least equal to the avoidable cost of providing a service to that User, as well as covering some "equitable" share of the common costs of service provision.

A difficulty arises, however, in defining a criterion of equity that is universally acceptable. In considering various perceptions of equity, the Regulator has given consideration to matters such as commonly accepted practices in the gas transmission industry that could be indicative of a generally accepted standards of equity in the specific context of the industry.

There may be a wide range of cost allocations and tariff structures that meet criteria of efficiency and equity. In general, the Regulator considers that the cost allocation and tariff structure should be a matter of commercial discretion for a Service Provider, subject to any proposed cost allocation and tariff structure being reasonably consistent with broad criteria of efficiency and equity.

With these considerations in mind, the Regulator addressed submissions on Epic Energy's proposed cost allocation, Reference Tariff and Reference Tariff structure, as discussed in the following section.

#### 5.9.3.2 Allocation of Costs Between Services

In deriving a tariff that corresponds to the proposed Total Revenue requirement for the DBNGP, Epic Energy adopted an assumption that all gas throughput for the Access Arrangement Period would occur under the proposed Reference Service (the Firm Service).

Several submissions questioned the appropriateness of this approach.

Western Power[259] indicated that since there is very little forecast increase in throughput over the Access Arrangement Period and hence very little projected use of the Firm Service, there are no costs associated with providing this service and hence no apparent reason for assuming that all costs are attributable to the service. Treasury/Office of Energy commented that it was not clear how revenue from existing contracts is taken into account in the determination of the Reference Tariff or otherwise treated as Rebatable Revenue.

In assessing Epic Energy's basic assumption to the allocation of costs and determination of the Reference Tariff, the Regulator considered the requirements of section 8.38 of the Code. Section 8.38 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. The Regulator considers that 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 differ 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. As such, the Regulator considers that an assumption that all forecast throughput occurs as the proposed Reference Service is a reasonable basis for cost allocation.

The Regulator notes that it is neither necessary nor appropriate in allocating costs to consider the expected revenue to be received from existing contracts. The purpose of doing so would be, supposedly, setting 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

[259] Western Power Submission 3

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 collect revenue) that was in existence prior to the date of the proposed Access Arrangement, which is contrary to the provisions of section 2.47 of the Code.

The Regulator is of the view that Epic Energy's approach to cost allocation – assuming that all gas throughput occurs as the Reference Service – meets the requirements of the Code.

#### 5.9.3.3 Zonal Tariff Structure and Allocation of Costs to Pipeline Zones.

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.

Submissions on the proposed Access Arrangement expressed concerns in regard to this proposed tariff structure. The concerns related to the use of a zonal tariff rather than a purely distance-based tariff, the proposed boundaries of the pipeline zones, the determination of compression charges in relation to pipeline zones, and inconsistencies in the description of zone boundaries and the actual determination of tariffs. Submissions on these four issues are addressed separately below.

**Postage-Stamp Versus Zonal Tariffs**

Submissions from AlintaGas,[260] Wesfarmers and CMS Gas Transmission drew attention to the creation of Zones 9 and 10 for that part of the DBNGP downstream of Compressor Station 9. These submissions noted that under the tariff structure of the *Dampier to Bunbury Pipeline Regulations 1998* all Users with Delivery Points in this part of the DBNGP would have faced a single "postage stamp" tariff. It was either stated or implied in these submissions that this tariff structure should be maintained. Cockburn Cement expressed a general view that the zonal structure provides for an inequitable cost allocation and tariff structure.

In considering Epic Energy's proposal for a zonal tariff structure, the Regulator gave attention to the way in which the zonal division of the pipeline is used in the specification of the Reference Tariff. In the description of the Reference Tariff structure in section 2.2 of the Access Arrangement Information, Epic Energy indicated that it is only the Pipeline Capacity Charge that is determined on the basis of pipeline zones. The other two quasi distance-based charges – the Compression Capacity Charge and the Compressor Fuel Charge – are described

[260] AlintaGas Submission 3.

as being based on the compression stations located between any Shippers Receipt Point and Delivery Point, and as such have no relation to the pipeline zones.

The Regulator has noted, however, that in actual determination of the Reference Tariff and specification of the Reference Tariff Policy in the proposed Access Arrangement, 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.

The Regulator regards compressor fuel costs and some other compression-related costs (particularly compressor maintenance costs) to be avoidable costs in the provision of services to a particular User. For the purposes of ensuring an efficient structure of the Reference Tariff, the Regulator will require that the compression charges be determined on a pass through basis, as proposed by Epic Energy in the Access Arrangement Information, rather than on a zone basis. The Regulator thus considers the zonal structure of the Reference Tariff to be important only in relation to the Pipeline Capacity Charge.

Epic Energy has proposed that this 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 charge on efficiency grounds. In regard to considerations of equity, the Regulator notes that 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. The Regulator is therefore of the view that the zonal structure of the Pipeline Capacity Charge cannot be rejected for reasons of being inequitable.

**Boundaries of Zones**

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.

Submissions from AlintaGas,[261] Wesfarmers and CMS Gas Transmission drew attention to the creation of Zones 9 and 10 for that part of the DBNGP downstream of Compressor Station 9. These submissions noted that under the tariff structure of the *Dampier to Bunbury Pipeline Regulations 1998* all Users with Delivery Points in this part of the DBNGP would have faced a single "postage stamp" tariff. It was either stated or implied in these submissions 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.

In considering the issue of pipeline zones downstream of Compressor Station 9, the Regulator recognised 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. As noted above, submissions on the proposed Access Arrangement appeared 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. The Regulator has taken the view that a distance based tariff is broadly supported, at least in principle, and as such sees 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.

Submissions addressed the proposed locations of zone boundaries, particularly the boundary between Zones 9 and 10. Western Power[262] questioned the appropriateness of specifying zone boundaries at locations one kilometre downstream of compressor stations (for downstream boundaries of Zones 1 to 9). AlintaGas,[263] Western Power,[264] WMC, North West Shelf Gas and the Chamber of Commerce and Industry drew attention to an inconsistency in the specification of the proposed boundary between Zone 9 and Zone 10 with the specification of other zone boundaries. 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 was suggested in the submissions that the boundary between Zones 9 and 10 has been located to capture the majority of the Perth metropolitan gas demand within Zone 10, and hence charge a higher tariff for this gas transmission. Western Power suggested that the Regulator require Epic Energy to demonstrate the equity of the proposed Zone 10 boundary location, and to justify zone boundaries in terms of considerations of pipeline operation and cost allocation.

Submissions from Worsley Alumina and the Bunbury Wellington Economic Alliance indicated that the establishment of the boundary for Zone 10 in a position upstream of the compressor station for Zone 10 results in Users with Delivery Points upstream of Compressor Station 10 paying costs associated with this compressor station. Worsley Alumina submitted that this breaks down the strict "user pays" principle in that Users on the Kwinana West and Rockingham laterals pay compression capacity and fuel charges for a compressor operating on the Pipeline South and reinforces the idea that the zoning system is designed to achieve a target price in Zone 9 rather than an equitable sharing of costs across all Users. The Bunbury

[261] AlintaGas Submission 3.
[262] Western Power Submission 3.
[263] AlintaGas Submission 3.
[264] Western Power Submission 5.

Wellington Economic Alliance expressed a view that the higher tariff for Zone 10 results in subsidisation of Users in Zones 1 to 9 by Users in Zone 10.

As noted above in relation to the zonal structure of the Reference Tariff, the Regulator considers that the zonal tariff structure should applied only in determination and imposition of the Pipeline Capacity Charge and not to compression charges. The location of zone boundaries is somewhat arbitrary, but for the purposes of determining the Reference Tariff the relative locations of zone boundaries and compressor stations are unimportant. 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, 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. As also noted above in relation to the zonal structure of the Reference Tariff, the zonal structure is consistent with commonly accepted criteria of equity in tariffs for gas transmission pipelines, and the Regulator does not consider that the zonal structure of the tariff, nor the proposed boundaries of zones, can be rejected on the basis of criteria of equity.

In regard to the submission from the Bunbury Wellington Economic Alliance expressing the view that higher tariff for Zone 10 results in subsidisation of Users in Zones 1 to 9 by Users in Zone 10, 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.

Submissions also commented on the treatment by Epic Energy of Zone 1 of the pipeline. CMS Gas Transmission, Apache Energy Limited and Western Power[265] 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 that this has the effect of negating cost advantages in gas transmission for gas producers closer to the South-West market.

North West Shelf Gas also commented on the proposal for all gas Receipt Points to be considered as 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

[265] Western Power Submission 3.

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.

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.

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.

The Regulator has 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. This charge is designed to recover fixed costs, and indeed predominantly sunk 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 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 meet this efficiency criterion, and the Regulator has no basis to reject the proposal on the basis of inefficiency.

In regard to matters of equity in Epic Energy's proposed definition of Zone 1 and the Pipeline Capacity Charge, the Regulator again notes 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. The Regulator is 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 does not consider there to be any reason to reject Epic Energy's treatment of Zone 1 for reasons of it being inequitable.

**Inconsistencies in Description of Zones and Application in Determination of Charges**

AGL Gas Transmission 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.

Both Epic Energy and the Regulator have noted this inconsistency in description of zones and allocation of Delivery Points to zones. Epic Energy has confirmed that the Eradu Road Delivery Point is indeed in Zone 6 of the pipeline. The Regulator has taken this into account in the determination of Reference Tariffs.

Amendment 60

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.

#### 5.9.3.4 Compression Charges and Pipeline Zones

North West Shelf Gas questioned the appropriateness of compression charges in Zone 1 of the Pipeline. 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.[266] However, in the determination of tariffs Epic Energy has incorporated the compression costs for Compressor Stations 1 and 2 with pipeline costs for Zone 1 and sought to recover all costs from the pipeline capacity charge for Zone 1. This results in the Users paying compression charges in proportion to contracted MDQ for Compressor Stations 1 and 2 regardless of whether a User's gas nominally passes through these compressor stations.

North West Shelf Gas suggested that the uniform charge from compression does not recognise differences in requirements for gas suppliers to compress gas prior to delivery into the DBNGP, with these differences dependent upon locations of Receipt Points relative to compressor stations. North West Shelf Gas also argues that the zonal tariff structure appears to recognise (but does not reward) the fact that the operation of the first section of the DBNGP from the North West Shelf Joint Venture plant to Compressor Station 1 relies upon the delivery of gas by the joint venturers at a pressure around 8.2 to 8.48 MPa(g). That is, the North West Shelf Joint Venture compression is, in effect, Compressor Station 0 for the DBNGP. Apache Energy delivers gas at much lower pressures around 6.5 to 7.0 MPa(g) into the suction of Compressor Station 1 and Onslow area producers deliver gas at similar pressures to the North West Shelf Joint Venture to the discharge of Compressor Station 2. North West Shelf Gas indicated this arrangement to be unfair in that compressor costs for Compressor Stations 1 and 2 will place the North West Shelf Joint Venturers and the Onslow producers at a cost disadvantage in supplying gas to the Goldfields Gas Pipeline when and if a connection between the Goldfields Gas Pipeline and the DBNGP is established.

The Regulator has noted that 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. One

[266] Access Arrangement Information, section 2.2.

result of this is that 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.

The Regulator regards compressor fuel costs and some other compression-related costs (particularly compressor maintenance costs) to be avoidable costs in the provision of services to a particular User. For the purposes of ensuring an efficient structure of the Reference Tariff, the Regulator will require that the compression charges be determined on a pass through basis, as proposed by Epic Energy in the Access Arrangement Information, rather than on a zone basis. That is, the while the pipeline zones remain relevant to the Pipeline Capacity Charge, they become irrelevant to the determination or specification of the Compression Capacity Charge. The consequence of this is that for forwardhaul of gas, users should only pay compression charges on a pass though basis, that is, in relation only to compressor located between the relevant gas Receipt Point(s) and gas Delivery Point(s). Moreover, compressor fuel charges should not apply to the back haul of gas.

The following amendments are required before the Access Arrangement will be approved.

| Amendment 61<br><br>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 between the gas Receipt Point(s) and gas Delivery Point(s) for each gas transmission contract. |
|---|

| Amendment 62<br><br>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. |
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#### 5.9.3.5 Forecast Throughput

Several submissions on the proposed Access Arrangement indicated that the forecast gas throughput for the Access Arrangement Period is inappropriately conservative and there are some anomalies in the forecast.

Submissions from AlintaGas,[267] Western Power[268], Treasury/Office of Energy and CMS Gas Transmission suggested that the capacity and volume forecasts are conservatively low with virtually no provision for increases in demand over the Access Arrangement Period, ignoring potential for significant new industrial developments such as the Mid-West Iron and Steel Project that would significantly increase gas consumption.

Western Power[269] draws attention to an apparent anomaly in Epic Energy’s throughput forecast in that the forecast annual volume for Zone 9 (76 to 80 TJ/day) substantially exceeds the forecast annual contracted-capacity (57 TJ/day). This is stated to be inconsistent with the

[267] AlintaGas Submission 3.

[268] Western Power Submission 3.

[269] Western Power Submission 3.

actual volume (80 to 100 TJ/day) and contracted capacity for 1998 (130 to 160 TJ/day). CMS Gas Transmission identifies the same anomaly for Zone 9 and similar anomalies for Zones 1a, 4a and 7, indicating differences in actual (1998) and forecast load factors for these zones as follows:

- Zone 1a: actual 1998 average load factor of 0.80 and forecast 2000 to 2004 average load factors of 0.52 to 0.54;
- Zone 4a: actual 1998 average load factor of 0.83 and forecast 2000 to 2004 average load factors of 1.00;
- Zone 7: actual 1998 average load factor of 0.63 and forecast 2000 to 2004 average load factors of 0.95 to 1.08; and
- Zone 9: actual 1998 average load factor of 0.62 and forecast 2000 to 2004 average load factors of 1.33 to 1.41.

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.

As will be described later in this section of the Draft Decision, the Regulator assessed the Reference Tariff without provision for deferred depreciation. As a consequence, the revised Reference Tariff indicated in this Draft Decision depends directly upon the forecast throughput.

Epic Energy's forecasts of contracted capacity and throughput are indicated 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).

The Regulator acknowledges that forecasts of contracted capacity and gas throughput are largely speculative and uncertain, and that for reasons of avoiding exposure to risk, a Service Provider may justifiably make and utilise conservative forecasts for the purposes of determining a Reference Tariff. The Regulator also notes, however, that a Service Provider also faces an incentive to utilise conservative forecasts of throughput in order to derive a higher Reference Tariff and increase the likelihood of capturing gains from increases in throughput over the Access Arrangement Period. In this and in previous decisions on Access Arrangements for Western Australian pipelines, the Regulator has countered this incentive, in part, by requiring Access Arrangements to include provision for a review of the relevant Access Arrangement if realised throughput is substantially in excess of the forecast throughput (typically where realised throughput reaches 125 percent of forecast throughput). While such a trigger mechanism may reduce the incentive for a Service Provider to understate expected throughput for an Access Arrangement Period, and limits the extent of windfall gains that may be captured by the Service Provider if realised throughput is in excess of the forecast, there is still substantial scope for the Service Provider to benefit by gaming on the throughput forecast. For this reason, the Regulator gave attention to Epic Energy's throughput forecast. The Regulator considered forecasts of both throughput and the contracted capacity, as both may separately influence the Reference Tariff.

In considering Epic Energy's forecast of contracted capacity and throughput, the Regulator has given attention to:

- forecasts by the Office of Energy of demand for natural gas over the period 2000 to 2009;[270]
- forecasts of gas throughput for the AlintaGas Mid-West and South-West Gas Distribution Systems;[271] and
- historical contracted capacity and gas throughput for the DBNGP for the years 1998, 1999 and 2000.

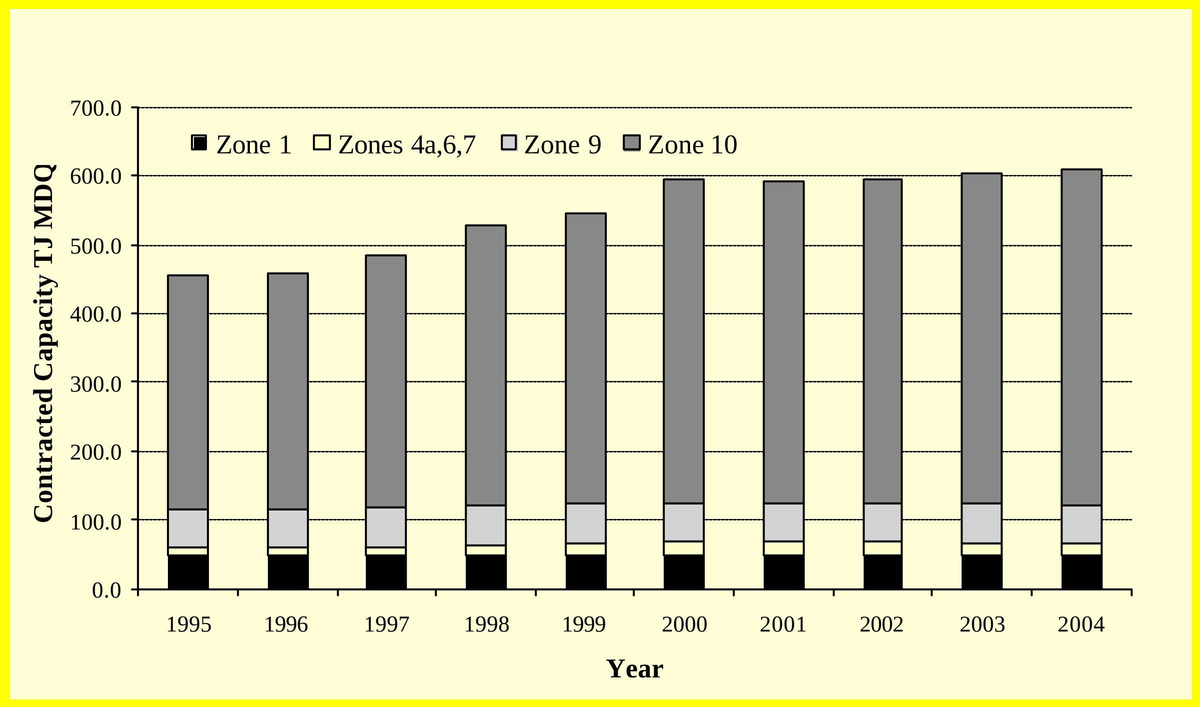
The Office of Energy has forecast increases in natural gas use in Western Australia of approximately eight percent per annum over the period 2000 to 2009 with a large part of these increases occurring in the approximate period 2003 to 2005. Part of this is attributable to projected increases in gas demand arising from major industrial projects that would be serviced by the DBNGP, including the Kingstream Steel project, the Mt Gibson Iron project and expansion of titanium dioxide processing operations at Kemerton. Further, the Office of Energy has forecast increases in domestic residential natural gas and electricity use over the period 2000 to 2009 by 2.2 percent and 2.4 percent per annum, respectively, although gas use for residential gas and electricity consumption would form a relatively minor part of total gas consumption.

AlintaGas has forecast an increase in gas throughput through its distribution systems of 3.8 TJ/day (5 percent) for the period 2000 to 2004, virtually all of which would be transported through the DBNGP. Epic Energy's forecast increase in throughput for the Access Arrangement Period is consistent with the AlintaGas forecast.

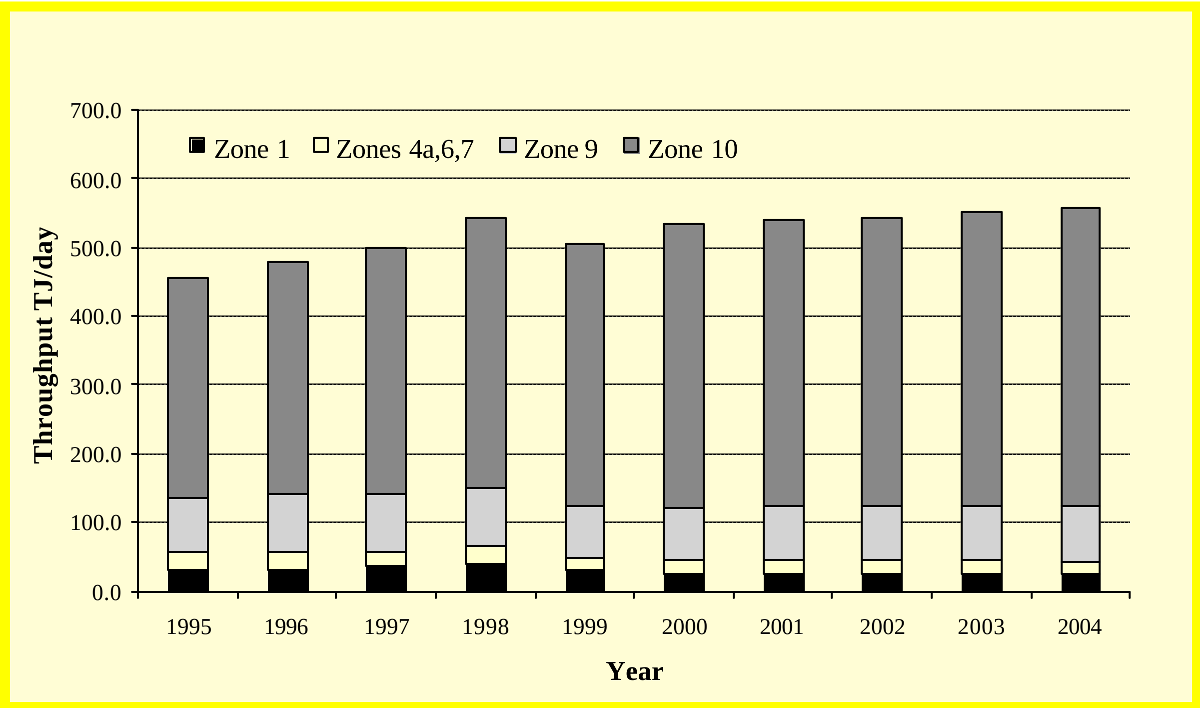
The Regulator obtained information from Epic Energy on historical contracted capacities, delivered volumes and average load factors. The time series for these historical data, and for forecasts used by Epic Energy for the determination of the Reference Tariff (2000 to 2005), are shown below.

[270] Office of Energy Western Australia, 2001. *Energy 2000 Western Australia*.

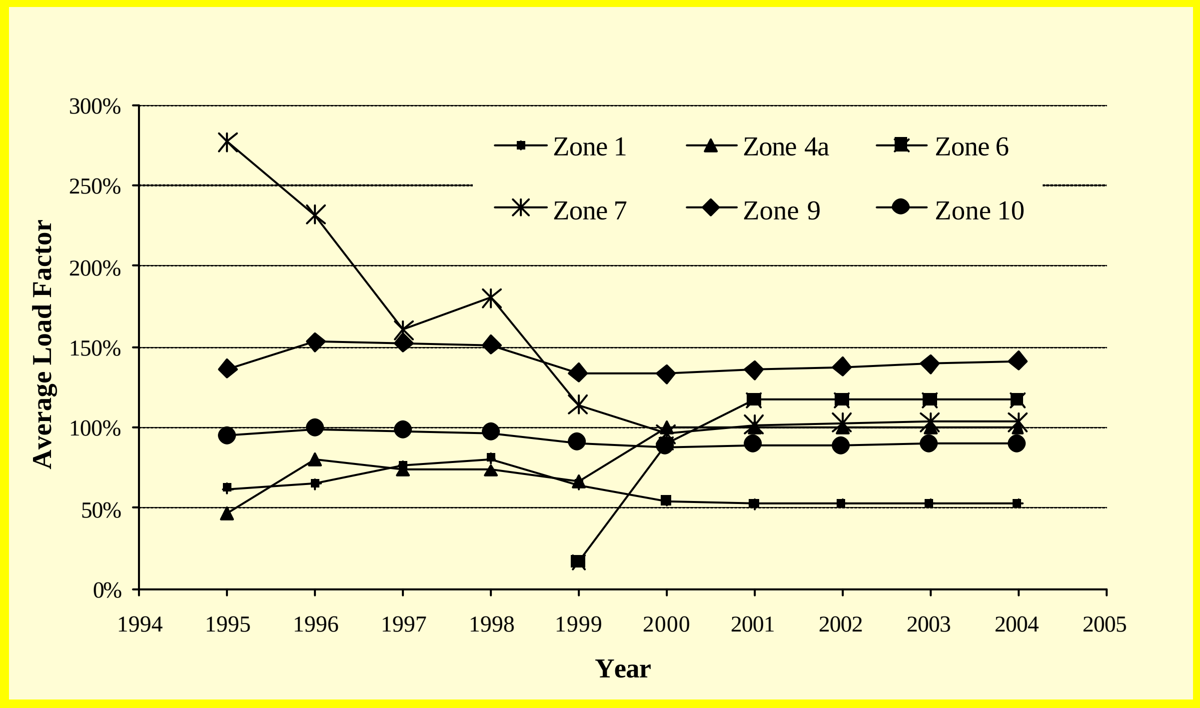
[271] AlintaGas, 2000. *AlintaGas's Access Arrangement Information for the Mid-West and South-West Gas Distribution Systems.*




**Historical and Projected Contracted Capacity**




**Historical and Projected Throughput Volumes**




**Historical and Projected Average Load Factors**

The Regulator notes the decrease in throughput volumes and Zone 9 and Zone 10 load factors between 1998 and 1999, which result primarily from reductions in throughput for AlintaGas and Western Power. These reductions may be attributed to the commissioning of the Collie Power Station and the reduction in gas requirements for electricity generation. Substantial changes in average load factors are also observed for Zone 1 (decreasing) and Zone 6 (increasing), attributable to changes in gas throughput while capacity remains constant.[272] The Regulator regards these variations as adequately explained by the forecast demands for gas throughput, and in any case immaterial to determination of the Reference Tariff by virtue of the small quantities of gas involved.

Overall, the Regulator is of the view that Epic Energy's throughput forecast is reasonable if major industrial projects such as the Kingstream and Mt Gibson projects are not taken into consideration. The Regulator notes the views expressed in submissions that throughput associated with these projects should be taken into account. However, given that neither project has yet commenced, the Regulator considers it inappropriate to require Epic Energy to take the throughput into account in determining the Reference Tariff. The Regulator also notes that Epic Energy has no Capital Expenditure for the current Access Arrangement Period that would be necessary to meet the service requirements of these projects, consistent with the approach taken with the throughput forecast.

[272] The Regulator notes that load factors in excess of 100 percent for Zones 6, 7 and 9 may result from throughput of gas in excess of contracted capacity, though purchase of additional interruptible or spot capacity.

#### 5.9.3.6 Magnitude of the Reference Tariff

**Overview**

Several submissions 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).

The submissions on the magnitude of the Reference Tariff are summarised below.

**Determination and Level of the Proposed Reference Tariff**

In regard to the general level of the proposed Reference Tariff, Western Power[273] made comments that insufficient information was provided in the Access Arrangement Information to ascertain how Epic Energy made the pro rata adjustment to the cost-based tariff to derive the proposed Reference Tariff, and that insufficient information was provided to enable verification that the proposed Reference tariff is indeed consistent with expected revenue for the DBNGP.

The Chamber of Commerce and Industry and WMC indicated a concern that Users would have difficulty comparing the Reference Tariff with existing tariffs for contracts entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998*. Both submissions suggested that Epic Energy be required to show a comparison between charges for existing Users and the charges that would apply to those Users under the Firm Service and Reference Tariff.

Both Western Power[274] and AlintaGas[275] indicated that the proposed Reference Tariff is, in effect, greater than tariffs under existing contracts entered into under the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998*. AlintaGas also indicated that by virtue of the high depreciation allowances made in the determination of tariffs under these regulations, these tariffs would have been expected to substantially decline after 2014 when the current assets are fully depreciated. In contrast, Epic Energy's proposed tariff would be maintained after 2014, imposing an unreasonable cost on Users.

**Tariff for Pilbara Delivery Points**

The Chamber of Commerce and Industry, Chamber of Minerals and Energy commented that increases in tariffs would be substantial for the Pilbara.

North West Shelf Gas indicated that under the proposed Access Arrangement, costs of gas transmission to Delivery Points in Zone 1a would increase by a multiple of 7.5 for Robe River Mining and 15.7 for Hamersley Iron. North West Shelf Gas indicated that these

[273] Western Power Submission 3.

[274] Western Power Submission 4

[275] AlintaGas Submission 4.

increases are material, excessive and unfair, and would have the effect of inhibiting development of the iron ore industry.

Hamersley Iron also indicated an expected increase in gas transmission costs under the proposed Reference Tariff approximately 14 times from the current tariff, increasing annual gas transportation costs from approximately $50,000 to $700,000, excluding the impact of any penalty charges. This was indicated to be inconsistent with reasonable expectations of Hamersley Iron as to future tariffs.

North West Shelf Gas also indicated that charges for delivery of gas to the vicinity of Compressor Station 1 in Zone 1b of the DBNGP would increase by 146 percent from $0.0979/GJ to $0.2411/GJ, with the effect of preventing potential delivery of gas to the Goldfields Gas Pipeline via the DBNGP, thus limiting potential competition between gas producers in supply of gas to consumers in the Goldfields.

Western Power[276] indicated that the proposed Reference Tariff would result in an increase in the average cost of gas transmission for its operations in the Pilbara from $0.025/GJ to $0.16/GJ. A similar increase is stated to occur by Robe River Mining. Western Power attributes the cost increase in part to the high asset valuation of the DBNGP and the inclusion in pipeline charges for Zone 1 of costs associated with Compressor Stations 1 and 2. Western Power indicated that the higher costs of gas transport would result in higher electricity costs in the Pilbara region and reduced economic development in that region.

**Tariffs for Carnarvon**

Under the Reference Tariff structure proposed by Epic Energy, a lateral pipeline from the DBNGP main pipeline to Carnarvon is treated as a separate pipeline zone (Zone 4a). Pipeline capacity charges are determined for this zone on the basis of the value of return on capital, depreciation and operating costs attributed to the lateral pipeline, and the forecast throughput for the pipeline. As a result of costs attributed to the lateral and forecast throughput of only approximately 1 TJ/day (for electricity generation at Western Power's Carnarvon Power Station), the unit pipeline capacity charge for gas transportation through the lateral is quite high, with the incremental charge for Zone 4a being $10.7285/GJ MDQ.

Treasury/Office of Energy and Western Power[277] have commented on the magnitude of this charge. Western Power indicated that the proposed Reference Tariff would result in an increase in the average cost of gas transmission from $4.40/GJ to $17.40/GJ. Western Power suggests that the large increase in gas transmission cost arises from the high asset value attributed to the Carnarvon lateral. Both Western Power and Treasury/Office of Energy indicate that the high cost of gas transport under the proposed Reference Tariff would have the effect of discouraging gas use at Carnarvon, and discouraging competition in the market for energy in Carnarvon.

**Tariffs to Mondarra**

North West Shelf Gas commented that the tariff for delivery of gas to Mondarra (approximately $0.774/GJ) is sufficiently high as to preclude any User from diverting gas into the Parmelia Pipeline for shipment to markets as an alternative to haulage in the DBNGP. At the proposed Parmelia Pipeline tariff of $0.55/GJ, the 100 percent load factor tariff to the Perth metropolitan area via the Parmelia pipeline would be $1.324/GJ, compared with $1.00/GJ for the DBNGP.

[276] Western Power Submission 1.

[277] Western Power Submission 1.

### Tariff for Zones 9 and 10

Several submissions included comment that the Reference Tariffs applying to Zones 9 and 10 of the DBNGP exceed the tariff of $1.00/GJ that Users may have been led to expect at the time of the DBNGP sale.

North West Shelf Gas and Worsley Alumina indicated that the tariff $1.08/GJ plus the Delivery Point Charge for Zone 10 is greater than a tariff of $1.00 that Users were reasonably led to believe would arise from the sale process.

Treasury/Office of Energy submitted that while Epic Energy has indicated that the proposed Reference Tariff for pipeline Zones 9 and 10 of $1.00 and $1.08 do not include the Delivery Point Charge which will add between $0.01/GJ and $2.20/GJ to the tariff, depending upon the charge applicable to each individual User. As such the proposed tariff may be inconsistent with the tariffs purportedly committed to by Epic Energy. AlintaGas indicated that the comparability of the Reference Tariff with the existing tariff of $1.00 under the *Dampier to Bunbury Pipeline Regulations 1998* is complicated by the difference in the proportion of fixed charges in the tariff. AlintaGas indicated that for any given load factor less than 100 percent, the effective gas transmission charge from nominal 100 percent load factor tariff of $1.00 is greater under Epic Energy's proposed tariff structure (with 95 percent of the 100 percent load factor tariff comprising fixed charges) than the current tariff (with 72.8 percent fixed charges).

AlintaGas indicated that an appropriate level of the Reference Tariff would be in the order of $0.84/GJ for a 100 percent load factor tariff with fixed charges comprising 72.8 percent of the tariff, or lower if the proportion of fixed charges is increased. WMC indicated an estimated tariff of $0.75/GJ, on the basis of an Initial Capital Base of $1.1 to $1.2 billion and real pre-tax WACC of 6.2 percent. Chamber of Minerals and Energy cited a similar figure based in a Capital Base of 1 billion and WACC of 8.5 percent. Mark Nevill MLC indicated that the appropriate tariff would be between $0.67 and $0.80/GJ (based on asset value of $1.0 to $1.2 billion and WACC of 7.5%).

### Regulator's Response to Submissions

In view of the substantial revisions of Epic Energy's proposed Reference Tariff being required by the Regulator, the Regulator has not responded to these matters raised in submissions in relation to the magnitude of the Reference Tariff. Rather the reader is referred to the next section of this Draft Decision (section 5.9.4) where an indicative Reference Tariff is set out, taking into account the Regulator's required amendments to the Access Arrangement.

The Regulator notes here, however, that the revised Reference Tariff as described in (section 5.9.4) is, for most Delivery Point Locations on the pipeline, substantially less than that proposed by Epic Energy, and less than tariffs currently applying (or that would apply under the *Dampier to Bunbury Pipeline Regulations 1998*) to Delivery Points at almost all locations on the pipeline. There are, however, anomalies in that higher tariffs would apply to Users or Prospective Users with Delivery Points in the Pilbara (Zone 1a of the pipeline) and from the Carnarvon Lateral (Zone 4a). In the case of Zone 1a, the increase in tariffs arises from the magnitude of Epic Energy's proposed Gas Receipt Charge. In the case of Zone 4a, it results from the high asset value ascribed to the Carnarvon Lateral pipeline.

The Regulator considers these anomalies to be inequitable given the reduction in tariffs for Delivery Points on other locations on the pipeline and requires Epic Energy to amend the cost allocation underlying the Reference Tariff so that for Users with Delivery Points in Zones 1a and 4a (and more generally for Users with delivery points in any zone), there is no increase in gas transmission costs under the Reference Tariff relative to the tariff that Users or Prospective Users would have paid under a contract entered into under the *Dampier to Bunbury Pipeline Regulations 1998*.

The following amendment is required before the Access Arrangement will be approved.

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|---|
| Amendment 63<br><br>The cost allocation and tariff structure should be amended to ensure that for Users or Prospective Users with Delivery Points in any zone of the DBNGP, there is no 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*. |

#### 5.9.3.7 Reference Tariff Structure

Submissions on the proposed Access Arrangement included comments on:

- the relative proportions of fixed and variable charges in the Reference Tariff;
- recovery by the Compressor Fuel Charge of forecast rather than actual costs of compressor fuel;
- allocation of compression costs to Zone 10 of the Pipeline;
- the basis for and working of the Gas Receipt Charge;
- the basis for and working of the Delivery Point Charge; and
- payment in advance of the Gas Receipt Charge and Pipeline Capacity Charge.

Submissions on each of these matters are summarised and responded to below.

**Relative Proportions of Fixed and Variable Charges in the Reference Tariff**

Several submissions drew attention to the proposal for only approximately five percent (or zero percent for Delivery Points in Zone 1) of the transmission charges under the Reference Tariff to be variable with a User's actual gas throughput.

Submissions from the Chamber of Commerce and Industry, North West Shelf Gas, AlintaGas,[278] Western Power,[279] Hamersley Iron and CMS Gas Transmission drew attention to the proportion of fixed charges in the Reference Tariff being greater than for tariffs of the *Gas Transmission Regulations 1994* and *Dampier to Bunbury Pipeline Regulations 1998*. It was generally noted 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.

[278] AlintaGas Submission 3.

[279] Western Power Submission 1.

North West Shelf Gas commented that the 100 percent fixed charge for Users with Delivery Points in Zone 1 would result in substantial increases in transmission costs for the Hamersley Iron and Robe River Mining Delivery Points, both of which have low load factors and relatively large seasonal differences in summer and winter gas throughput. Hamersley Iron indicated the transfer of all throughput risk to Users with Delivery Points in Zone 1a of the pipeline is inequitable.

Western Power[280] proposed that capital-related costs (return on capital and depreciation) and fixed Non-Capital Costs should be recovered in charges levied against contracted MDQ and variable Non-Capital Costs recovered in charges levied against actual throughput.

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.

The Regulator notes that 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.

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. The Regulator is 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. The Regulator, however, accepts Epic Energy's argument that within the range of short-term fluctuations in throughput, compression maintenance costs may be regarded as fixed costs. In view of this, the Regulator considers that the proposed tariff structure that has only compressor fuel costs being recovered as a throughput charge is not inconsistent with criteria of economic efficiency.

The Regulator notes 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 one, the relatively small throughput component of the proposed Reference Tariff would have the result of producing a lower "100 percent load factor" tariff. 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 AlintaGas's submission that indicated an 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. The Regulator considers

[280] Western Power Submission 5.

that this has the effect of reducing the exposure of Epic Energy to cyclical economic fluctuations affecting demand for gas transmission, and has taken this into account in assessing the Rate of return for the DBNGP (see section 5.6 of this Draft Decision).

The Regulator is requiring amendments to the proposed Access Arrangement that will reduce the potential impacts of the low throughput charge component of the Reference Tariff on Users. Firstly, the Regulator is requiring that the Services Policy for the DBNGP be amended to provide for Users to contract for different amounts of MDQ for different months. This will enable Users to better manage contracted capacity to maximise load factors and minimise costs of gas transmission. Secondly, the Regulator is requiring revision of the Reference Tariff to reflect a lower value of the Capital Base for the DBNGP and lower costs of capital expenditure. This has the effect of increasing the value of compressor fuel costs relative to the costs of service provision, and hence increases the proportion of the Reference Tariff that is recovered from the throughput charge. Under the Regulator's revised tariff, the Compressor Fuel Charge comprises approximately 10 percent of the 100 percent load factor tariff for transmission of gas to Delivery Points downstream of pipeline Zone 1.

In view of the above, the Regulator considers that there is no reason to reject Epic Energy's proposal for the Reference Tariff to provide for throughput charges to amount to only a small proportion of the total tariff.

**Compressor Fuel Charge**

Epic Energy has estimated the costs of compressor fuel for the Access Arrangement Period and has proposed to recover this cost through the Compressor Fuel Charge.

North West Shelf Gas commented that the charging for use of compressor fuel on the basis of forecast fuel use reduces incentives for Epic Energy to efficiently operate the pipeline. Further, North West Shelf Gas commented that as the use of compressor fuel is metered, it should be possible for the Compressor Fuel Charge to be determined on the basis of actual fuel used rather than a forecast, possibly subject to a maximum unit cost. The implication of this would be that Compressor Fuel Charges would be levied as a charge separate to the Reference Tariff.

Contrary to the view expressed by North West Shelf Gas, the Regulator is of the view that the proposal for recovery of compression fuel costs in the manner proposed by Epic Energy does provide an incentive for efficient operation of the pipeline for the reason that the benefits of any cost savings achieved through efficient operation of compression would be captured by Epic Energy. Subject to the reasonableness of the forecast costs of compressor fuel, the Regulator sees no reason to reject this approach to recovery of compressor fuel costs.

**Compression Charges in Pipeline Zone 10**

Worsley Alumina, the Bunbury Wellington Economic Alliance, and the South West Development Commission questioned the appropriateness of the allocation of compression related costs for Compressor Station 10 to Users with Delivery Points downstream of this compressor station. It was submitted 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. Worsley Alumina questioned whether Wesfarmers LPG should be meeting part of these compression costs and suggested that the Regulator investigate the contractual Arrangements between Epic Energy and Wesfarmers LPG in this regard.

The Regulator is of the understanding that the contractual arrangements between Epic Energy and Wesfarmers LPG requires that Wesfarmers LPG is required to return gas to the DBNGP at a 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 Regulator notes that the requirement for Compressor Station 10 arises from increases in demand for services downstream of the Wesfarmers LPG plant. In view of both these factors, the Regulator considers it reasonable that the costs associated with Compressor Station 10 are recovered from Users with Delivery Points downstream of this compressor station.

**Gas Receipt Charge**

North West Shelf Gas commented that it is not possible to form a view from the information provided as to whether the proposed Gas Receipt Charge recovers or over-recovers the overhead Non-Capital Costs that it is purported to recover. Further, North West Shelf Gas and Hamersley Iron suggested that some of the operating costs are likely to be variable and as such, insufficient information has been presented to justify levying of the Receipt Point Charge on MDQ rather than actual quantities shipped. Hamersley Iron also indicated that the Gas Receipt Charge appears to recover costs of gas used in operations, which should be recovered through the Compressor Fuel Charge and not recovered at all from Users with Delivery Points in Zone 1a.

Robe River Mining and Hamersley Iron indicated that the levying of the Gas Receipt Charge on the basis of contracted MDQ results in the same charge applying to all Users regardless of the distance of gas transportation, implying that this is not a equitable recovery of costs.

Epic Energy has determined the Gas Receipt Charge to recover costs attributable 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 station, and metering assets.

In information provided to the Regulator additional to the Access Arrangement Information, Epic Energy indicated that the Non-Capital Costs recovered by the Gas Receipt Charges included costs associated with finance and administration, human resources, legal services, information technology, marketing and business development, public relations, corporate overheads and "special projects". The Regulator is 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 notes that the costs recovered by the charge do include costs for other gas used in operations such as gas lost in blowdowns and purges.

The Regulator is 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 the costs between Users is largely arbitrary, although the allocation may be assessed against broad considerations of equity.

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, the Regulator considers that this basis for the Gas Receipt Charge is something of an arbitrary compromise between a fixed charge per user and a charge levied on a basis of distance and quantity of gas delivered.

In view of this, the Regulator does not consider there is reason to reject, in principle, Epic Energy's proposed basis for levying the Gas Receipt Charge.

Notwithstanding this, the Regulator notes that the Gas Receipt Charge, as currently determined, is the principle factor contributing to the Reference Tariff for gas transmission to Delivery Points in Zone 1a being greater than the tariff that would currently apply under the *Dampier to Bunbury Pipeline Regulations 1998*. For the purposes of this Draft Decision, the Regulator has addressed this issue by incorporating the Gas Receipt Charge into the Pipeline Capacity Charge. It is, however, recognised that this is not the only option available for restructuring of the Reference Tariff to address this issue.

### Delivery Point Charge

Epic Energy has proposed that the Delivery Point Charge recover costs attributable to:

- return on Delivery Point assets; and
- depreciation of Delivery Point assets.

Western Power[281], North West Shelf Gas and Hamersley Iron commented that insufficient information was provided in the Access Arrangement Information to verify the Delivery Point Charges. The information that would be necessary to be able to verify the charges would be the capital value of the Delivery Point assets and the depreciation schedule for particular assets. North West Shelf Gas also indicated that it is not clear whether the 'user specific' operating and maintenance costs currently paid by Shippers for Epic Energy to operate and maintain User specific delivery facilities will still be paid under the proposed Access Arrangement or whether these are included in the Reference Tariff.

North West Shelf Gas, Western Power[282] and Treasury/Office of Energy drew attention to claimed difficulties in determining the Delivery Point Charges for individual Users that jointly utilise delivery facilities. In particular, North West Shelf Gas commented on Epic Energy's proposal to determine the Delivery Point Charge for each User in proportion to the daily throughput by the Users sharing that Delivery Point. North West Shelf Gas suggested that this might not be possible or practical where the Users themselves do not apportion gas throughput prior to actual gas receipt. Treasury/Office of Energy also drew attention to problems in determining Delivery Point Charges for shared Delivery Point facilities on the basis of proportions of gas throughput, indicating that this may result in some Users that have contracted MDQ but no throughput for a particular period not paying any Delivery Point Charge for that period.

Hamersley Iron submitted that the proposed Delivery Point Charge for Hamersley Iron's Delivery Point in Zone 1a is unreasonably high compared to the charges made against other equivalent facilities. The charge of $303.36/day is approximately 1.5 cents/GJ, based on Hamersley Iron's contracted capacity of 20 TJ/day.

AGL[283] indicated the Delivery Point Charge to which it would be liable under the Reference Tariff is anomalous given that it paid the full capital cost of the delivery facilities.

In considering Epic Energy's proposed Delivery Point Charge and the public submissions made on this matter, the Regulator gave consideration to the following matters:

[281] Western Power Submission 3.
[282] Western Power Submission 5.
[283] AGL Submission 2.

- 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 Delivery Point Charges where Delivery Points are used by multiple Users.

The Regulator notes that 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.

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 the cost of which was not met by either Epic Energy or previous owners of the DBNGP.

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.

The Regulator has no in-principle objection to the Reference Tariff including a charge specifically for the recovery of capital costs of Delivery Point facilities. However, the Regulator considers that the current proposal that would allow Epic Energy, at least in the first instance, to retain revenue from these charges where Users meet the costs of the facilities, is inconsistent with a reasonable balance between the interests of the Service Provider and Users. The Regulator will therefore require that the proposed Access Arrangement be amended to set out mechanisms by which any recovery of capital costs in respect of Delivery Point facilities that have been financed by Users are returned to the Users that have financed those facilities.

A further concern of the Regulator 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 by Epic Energy to the Regulator both as part of and in addition to the Access Arrangement Information, 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 and should be addressed in any amendment of the Access Arrangement. In accordance with the methodology used by the Regulator in determining the Initial Capital Base for the DBNGP, the Delivery Point facilities should be valued by a DORC methodology. The Regulator has estimated such values for the purposes of this Draft Decision by pro rata adjustments to Epic Energy's valuation of Delivery Point assets, but recognises these values remain somewhat arbitrary. The Regulator will attempt to resolve these values prior to issue of a Final Decision. In any case, the Regulator is of the view that 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.

The following amendment is required before the proposed Access Arrangement will be approved.

Amendment 64

The proposed Access Arrangement should be amended to include a mechanism to ensure that revenues from the Delivery Point Charge are not retained by Epic Energy where those revenues recover capital costs attributed to capital assets that were financed by Users.

The Regulator notes the concerns expressed by North West Shelf Gas, Western Power[284] and Treasury/Office of Energy as to the difficulty in determining Delivery Point Charges where Delivery Points are shared by Users. The Regulator is of the view that the Access Arrangement provides insufficient information in this regard and will require the Access Arrangement and/or Access Contract Terms and Conditions to be amended to address this matter.

The following amendment is required before the Access Arrangement will be approved.

Amendment 65

The proposed Access Arrangement and/or Access Contract Terms and Conditions should be amended to describe how the Delivery Point Charge will be determined for Users where those Users share Delivery Point facilities and where Users take delivery of gas from Nominal Delivery Points.

#### 5.9.3.8 Payment of Charges in Advance

North West Shelf Gas and Robe River Mining drew attention to the requirement for payment of the Gas Receipt Charge and Pipeline Capacity Charge in advance. North West Shelf Gas 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".

[284] Western Power Submission 5.

Robe River Mining commented that 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.

Epic Energy has not proposed to include a component of working capital in the Initial Capital Base. Neither has the Regulator considered working capital in assessment of the Initial Capital Base for the purposes of this Draft Decision. In view of this, Epic Energy's proposal for payment of charges in advance has not influenced the Regulator's consideration of any working-capital component of the Initial Capital Base, and hence nor the value of the Initial Capital Base.

In regard to interruptions to supply as a result of force majeure events, The Regulator is requiring that Epic Energy amend the proposed Access Contract Terms and Conditions to make provision for the waiving of applicable capacity charges where it claims force majeure has occurred (Amendment 22, section 4.3.3 of this Draft Decision). 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.

### 5.9.3.9 Prudent discounts

AlintaGas[285] submitted that in approving a Reference Tariff, the Regulator 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 section 8.43 of the National Access Code. 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 argues 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*. Further, 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.

Apache Energy Limited commented that the issue of the relationship between tariff and gas quality has not been addressed, arguing that AlintaGas has access to a tariff reduction of 50 percent for transport of producer LPG to Wesfarmers and that for tariffs to be cost reflective, Shippers with rich gas should expect to pay a lower tariff than those with lean gas.

The Regulator has observed that 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.

[285] AlintaGas Submission 4

Such 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. The Regulator also notes that the discount provided to AlintaGas in respect of gas delivered to the Wesfarmers LPG may be a condition of a haulage contract between Epic Energy and AlintaGas

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, the Regulator 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.

In relation to the more general issue of whether the Reference Tariff should provide for different charges for gas of different energy densities, the Regulator notes that the proposed Access Contract Terms and Conditions includes a gas specification with a relatively narrow range of maximum and minimum heating values, and a minimum LPG content. The Regulator recognises that, in principle, there would be economies in transporting gas of higher energy density. Notwithstanding this, the Regulator recognises that current arrangements for the transmission of LPG in the DBNGP will expire in 2005 and hence arrangements for transport of LPG through the DBNGP would be expected to change after this date.

#### 5.9.3.10 Rebatable Services

In section 9 of the proposed Access Arrangement, Epic Energy has proposed that some Non-Reference Services be deemed 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.

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 section 5.9.2 of this Draft Decision.

Treasury/Office of Energy and AlintaGas[286] expressed concern that 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. It was noted that while some of the Non-Reference Services were designated to be Rebatable Services, others (such as the Peaking Service) are not. These submissions imply concern that 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.

[286] AlintaGas Submission 3.

In considering the concerns expressed by Treasury/Office of Energy and AlintaGas, the Regulator 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. In this regard the Regulator first notes that the Seasonal Service is required to be incorporated into the Reference Service and so will not exist as a separate Non-Reference Service (Amendment 1). With the Secondary Market Service, prices are proposed to be determined on a spot market basis, with prices reflecting the supply and demand for capacity at any given time. With price determination by this method, prices may be greater than the level necessary for Epic Energy to recover the costs of providing the services, and hence it is reasonable that part of the excess should be rebated to Users. For the other 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, User's 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 provisions for arbitration may therefore serve to limit the setting of prices for Non-Reference Services at levels above the cost of providing the service. As such, the Regulator does not consider that it is necessary for the Access Arrangement to make provision for Non-Reference Services other than the Secondary Market Service to constitute Rebatable Services.

Worsley Alumina commented that in determining Rebatable Revenue, Epic Energy should only be able to retain that amount of revenue equal to the operating, maintenance and other non-capital costs incurred in providing the Rebatable Services. Treasury/Office of Energy, and Worsley Alumina, questioned the appropriateness of payment of 40 percent of Distributable Revenue into Epic Energy's deferred recovery account, which may be, in effect, retention of revenue by Epic Energy.

In considering an appropriate proportion of the Rebatable Revenue (or Distributable Revenue in the terminology used by Epic Energy), the Regulator gave attention to provisions of the Code in respect of Rebatable Services. 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. The Regulator is of the view that provision of such an incentive would require that the Service Provider be able to retain a portion of revenue from 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 this retained revenue 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). The Regulator considers that retention by Epic Energy of 15 percent of Distributable Revenue may provide sufficient incentive to offer the Non-Reference Services. However, the Regulator notes that under required revisions to the proposed Access Arrangement in respect of the Initial Capital Base and Reference Tariff (see section 5.9.4 of this Draft Decision) there is no requirement for a deferred recovery account. The Regulator therefore requires that the proposed Access Arrangement be amended to provide for the distribution of Distributable Revenue as 15 percent to be retained by Epic Energy, and 85 percent to be distributed to Rebate Sharing Shippers.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 66<br><br>Paragraph 9.2(b) of the proposed Access Arrangement should be amended to provide for distribution of Distributable Revenue in proportions of 15 percent to be retained by Epic Energy and 85 percent to be distributed to Rebate Sharing Shippers. |

Western Power[287] indicated a view 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. Western Power 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. Western Power also indicated that insufficient information was provided for Shippers to be able to assess the likelihood of a distribution at any time.

The Regulator is of the view that Western Power's suggestion of requiring 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. To require Epic Energy to make rebates to holders of prior contracts would, in the Regulator's view, 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. The Regulator therefore will not require the proposed Access Arrangement to be amended to make provision for rebates of Distributable Revenue to holders of prior contracts.

In regard to Western Power's submission that insufficient information was provided for Shippers to be able to assess the likelihood of a distribution at any time, the Regulator notes 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. The Regulator does not, however, regard this 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.

Treasury/Office of Energy commented that Epic Energy has not provided sufficient information to enable Users to determine the adequacy of the proposed method of rebate. In particular, Treasury/Office of Energy pointed out 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 of gas delivered in the year in excess of the forecast volume for that year.

The Regulator agrees 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 in section 5.9.2 of this Draft 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

[287] Western Power Submission 3.

revenue due to the out-workings of the contract between Epic Energy and Alcoa.. The Regulator considers 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.

In addition to the matters discussed in submissions in relation to the Rebatable Services, the Regulator has 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 Firm Service, plus the cost of providing those services from which Rebatable Revenue was obtained. The Regulator notes that Epic Energy may provide services of a similar nature to the Firm Service as a Non-Reference Service, that is, 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.

The Regulator is therefore of the view that this 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. To overcome this problem, the Regulator will require the method of calculation of Threshold Revenue to be revised 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.

The following amendment is required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 67<br><br>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. |

### 5.9.4 Additional Considerations of the Regulator

In addressing concerns expressed in public submissions in regard to the proposed cost allocation and the Reference Tariff, the Regulator drew the following conclusions.

- Epic Energy's proposal to calculate the Reference Tariff on the basis of an assumption that all forecast throughput under contracts for firm capacity occurs as the proposed Reference Service is a reasonable basis for cost allocation. It is neither necessary nor appropriate in the allocation of costs to consider the expected revenue to be received from existing contracts.

- Epic Energy's throughput forecast appears reasonable if major industrial projects such as the Kingstream and Mt Gibson projects are not taken into consideration. The Regulator regards such an approach to throughput forecasts to be appropriate.
- The zonal basis for setting and levying the Pipeline Capacity Charge is consistent with broad criteria of efficiency and equity in a tariff structure, and the Regulator sees no reason to reject this proposed structure of the Pipeline Capacity Charges. However, the Regulator will require that the specification of the Reference Tariff be amended to remove some inconsistencies in the specification of charges for zones, particularly in respect of the application of charges for the Eradu Road Delivery Point (Amendment 60).
- It is not appropriate to determine compression-related charges on a basis of pipeline zones. For the purposes of ensuring an efficient structure of the Reference Tariff, the Regulator will require that the compression charges be clearly distinguished from the Pipeline Capacity Charge and from the zonal basis of the Pipeline Capacity Charge (Amendment 61), and that the compression charges be determined on a pass through basis rather than on a zone basis (Amendment 62).
- The Regulator sees no reason to reject Epic Energy's proposed cost allocation or tariff structure, but will require that some amendment be made of these to ensure that for Users with Delivery Points in Zone 1a there is no increase in gas transmission costs under the Reference Tariff relative to the tariff that Users would have paid under a contract entered into under the *Dampier to Bunbury Pipeline Regulations 1998* (Amendment 63).
- There are no reasons based on criteria of efficiency or equity to reject Epic Energy's proposal for the Reference Tariff to include throughput charges that recover only costs of compressor fuel and that amount to only a relatively small proportion of the 100 percent load factor tariff.
- There is no reason to reject Epic Energy's proposal for a Delivery Point Charge. However, the Regulator will require that the proposed Access Arrangement be amended to set out mechanisms by which any recovery of capital costs in respect of Delivery Point facilities that have been financed by Users are returned to the Users that have financed those facilities, and that Users capture the benefits of any upward revaluation of Delivery Point facilities that were financed by Users (Amendment 64).
- The provisions of the proposed Access Arrangement in respect of Rebatable Revenue are considered to be consistent with the relevant requirements and objectives of the Code. The Regulator will however require that the proposed Access Arrangement be amended to provide for the distribution of Distributable Revenue as 15 percent to be retained by Epic Energy, and 85 percent to be distributed to Rebate Sharing Shippers (Amendment 66) and to provide for the determination of "Threshold Revenue" to include revenue from the sale of both the Firm Service as well as other services in the nature of the Firm Service (Amendment 67).

Notwithstanding the general acceptance of the proposed cost allocation and tariff structure, the Regulator will require that the Reference Tariff be revised to reflect the required revisions to the Initial Capital Base, Capital Expenditure, Operating Expenditure, Rate of Return and Depreciation Schedule as described in this Draft Decision. The Regulator has determined an indicative Reference Tariff that could result from these revisions (and therefore the Total Revenue as described in section 5.8.4 of this Draft Decision) while being consistent with the general tariff determination methodology, cost allocation and tariff structure proposed by Epic Energy.[288]

The Regulator's revised Reference Tariff presented in this Draft Decision is based on a number of methodological assumptions as follows:

- Straight-line depreciation of assets.
- In order to ensure that the Reference Tariff that would apply to Users with Delivery Points in Zone 1a of the pipeline would be closer in value to the tariff that would apply under the *Dampier to Bunbury Pipeline Regulations 1998*, the Regulator has re-allocated the costs that would have been recovered by the Gas Receipt Charge to be recovered through the Pipeline Capacity Charge. It is, however, recognised that this is not the only means by which Epic Energy may meet this requirement of the Regulator. No cost reallocation was undertaken for Zone 4a but this will need to be addressed by Epic Energy to achieve the stated objective of there being no increase in gas transmission costs under the Reference Tariff relative to the tariff that Users taking delivery of gas in Zone 4a would have paid under a contract entered into under the *Dampier to Bunbury Pipeline Regulations 1998*.
- The revised Reference Tariff provides for full compensation to Epic Energy for inflation over the Access Arrangement Period. The revised Reference Tariff is presented in dollar values as at 1 July 2000, which would have been the tariff applying for the year 2000 and that include a half-year inflation adjustment. For the purposes of tariff smoothing over the Access Arrangement Period, the Regulator has assumed a tariff path involving annual adjustment of tariffs by 67 percent of the change in the Consumer Price Index (CPI), as proposed by Epic Energy. This has the effect of providing Epic Energy with a higher Reference Tariff in the beginning of the Access Arrangement Period (and lower tariff at the end) than otherwise would apply if full CPI adjustment was assumed, but provides for the same return of Total Revenue in net present value terms.

The Regulator's revised Reference Tariff excludes goods and services tax. The Regulator is of the view that it is appropriate to accommodate the pass through of the goods and services tax in the Reference Tariff, as it will be set out in the Access Arrangement. Epic Energy has proposes pass through of the goods and services tax at a rate of 9.98 percent of the goods and services tax exclusive tariff. The Regulator will specify a goods and service tax inclusive Reference Tariff in the Final Decision.

As noted in section 4.2.3 of this Draft Decision, the Regulator requires that the Reference Tariff be structured in such a way as to provide for distance-based charging for gas received into the pipeline at points in pipeline zones other than Zone 1. This may be achieved by specifying the Pipeline Capacity Charge, Compression Capacity Charge and Compressor Fuel Charges in incremental amounts for each zone rather than as cumulative values from Zone 1. The incremental values for these charges corresponding to the indicative Reference Tariff set out above are detailed below. Note the charges that would apply are calculated by adding the individual zone charges between and inclusive of the gas receipt point location and the gas delivery point.

[288] Determination of the Reference Tariff also relies on assumptions as to quantities of gas received into the pipeline at Receipt Points and delivered at Delivery Points. In this respect, the Regulator relied on information provided by Epic Energy, as well as forecast volumes of gas received into the DBNGP from the Tubridgi Pipeline System as set out in the proposed Access Arrangement for that pipeline.

The following tables show the Reference Tariffs that would apply from 1 January 2000 to 31 December 2000. No Gas Receipt Charge is shown as the Regulator, for the purposes of this Draft Decision, has recovered costs formally allocated to this charge through the Pipeline Capacity Charge.

**Revised Pipeline Capacity Charges expressed as zonal increments (1 July 2000 $/GJ MDQ, excluding goods and services tax)**

| Individual zone pipeline capacity charge for each zone gas passes through (partially or fully) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Zone 1a | Zone 1b | Zone 2 | Zone 3 | Zone 4 | Zone 4a | Zone 5 | Zone 6 | Zone 7 | Zone 8 | Zone 9 | Zone 10 |
| 0.0120 | 0.0893 | 0.0484 | 0.0497 | 0.0498 | 8.9280 | 0.0507 | 0.0513 | 0.0579 | 0.0533 | 0.0705 | 0.0983 |

**Revised Compression Capacity Charges expressed as increments for each compressor station (1 July 2000 $/GJ MDQ, excluding goods and services tax)**

| Individual zone compression capacity charge for each compressor station gas passes through | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| CS1 | CS2 | CS3 | CS4 | CS5 | CS6 | CS7 | CS8 | CS9 | CS10 |
| 0.0118 | 0.0132 | 0.0175 | 0.0098 | 0.0174 | 0.0175 | 0.0112 | 0.0178 | 0.0154 | 0.0111 |

**Revised Compressor Fuel Charges expressed as increments for each compressor station (1 July 2000 $/GJ throughput, excluding goods and services tax)**

| Individual compressor fuel charge for each compressor station gas passes through | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| CS1 | CS2 | CS3 | CS4 | CS5 | CS6 | CS7 | CS8 | CS9 | CS10 |
| 0.0074 | 0.0082 | 0.0078 | 0.0078 | 0.0079 | 0.0079 | 0.0079 | 0.0081 | 0.0081 | 0.0066 |

For purposes of comparison with the Reference Tariff set out by Epic Energy in the proposed Access Arrangement, the following tables set out the Reference Tariff as accumulated charges applicable to transportation services between Woodside, located in Zone 1a, and a delivery point located in any zone south of this receipt point. These numbers are directly comparable with the tariffs proposed by Epic Energy in the proposed Access Arrangement. If gas is sourced from a supplier located in any other zone the applicable tariff will differ from that shown below.

**Revised Pipeline Capacity Charges with gas Receipt Point located in Zone 1a (1 July 2000 $/GJ MDQ, excluding goods and services tax)**

| 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 |
| 0.0120 | 0.1012 | 0.1496 | 0.1993 | 0.2491 | 9.1771 | 0.2998 | 0.3511 | 0.4090 | 0.4623 | 0.5328 | 0.6311 |

**Revised Compression Capacity Charges with gas Receipt Point located in Zone 1a (1 July 2000 $/GJ MDQ, excluding goods and services tax)**

Delivery point located between:

| Dampier & CS1 | CS1 & CS2 | CS2 & CS3 | CS3 and CS4 | CS4 & CS5 | CS5 & CS6 | CS6 & CS7 | CS7 & CS8 | CS8 & CS9 | CS9 & CS10 | CS10 & MLV157 |
|---|---|---|---|---|---|---|---|---|---|---|
| – | 0.0118 | 0.0250 | 0.0425 | 0.0523 | 0.0697 | 0.0872 | 0.0984 | 0.1162 | 0.1316 | 0.1426 |

**Revised Compressor Fuel Charges with gas Receipt Point located in Zone 1a (1 July 2000 $/GJ, excluding goods and services tax)**

Delivery point located between:

| Dampier & Zone 1a | Zone 1a & CS2 | CS2 & CS3 | CS3 and CS4 | CS4 & CS5 | CS5 & CS6 | CS6 & CS7 | CS7 & CS8 | CS8 & CS9 | CS9 & CS10 | CS10 & MLV157 |
|---|---|---|---|---|---|---|---|---|---|---|
| – | 0.0074 | 0.0157 | 0.0235 | 0.0313 | 0.0392 | 0.0471 | 0.0549 | 0.0631 | 0.0712 | 0.0778 |

In addition to the charges set out above, the Reference Tariff includes the Delivery Point Charge, as set out below.

**Revised Delivery Point Charge**
**(1 July 2000 $/day excluding goods and services tax)**

| Delivery Zone | Delivery Point | Charge |
|---|---|---|
| Zone 1a | Hamersley Iron | 135 |
| | Robe River | 87 |
| Zone 4 | Carnarvon | 78 |
| Zone 6 | Eradu Road | 57 |
| Zone 7 | Geraldton (Nangetty Road) | 74 |
| | Mungarra | 114 |
| | Pye Road | 70 |
| | Mondarra | 64 |
| | Mount Adams Road | 68 |
| | Eneabba | 77 |
| Zone 9 | Muchea | 95 |
| | Della Road | 49 |
| | Pinjar | 293 |
| | Ellenbrook | 65 |
| | Harrow Street | 115 |
| | Caversham | 76 |
| | Welshpool | 120 |
| | Forrestdale | 117 |
| | Russell Road | 76 |
| Zone 10 | Wesfarmers LPG | |
| | Australian Gold Reagents | 61 |
| | Alcoa Kwinana | 186 |
| | Kwinana Power Station | 339 |
| | Barter Road/HiSmelt | 146 |
| | Mission Energy Cogeneration | 60 |
| | Thomas Road | 82 |
| | Kwinana Beach Road | 93 |
| | WMC | 66 |
| | Rockingham | 73 |
| | Pinjarra | 71 |
| | Alcoa Pinjarra | 243 |
| | Oakley Road | 62 |
| | Alcoa Wagerup | 171 |
| | Harvey | 78 |
| | Worsley | 160 |
| | South West Cogeneration | 52 |
| | Kemerton | 66 |
| | Clifton Road | 80 |

The Delivery Point Charge would add, on average, a further 3.4 cents per gigajoule to the Reference Tariff, based on current throughput to delivery points, although this varies between 0.2 cents and 15.4 cents per gigajoule.

For gas transmission with a 100 percent load factor and the average value for the Delivery Point Charge, the total tariff charge for gas transmission from Receipt Points in zone 1a to Delivery Points in each zone with existing delivery points would be as follows.

**Indicative Tariffs under the revised Reference Tariff for pipeline zones with existing Delivery Points, with 100 percent load factor delivery and average value of Delivery Point Charge (1 July 2000 dollar values excluding goods and services tax)**

| Delivery Point Location | Total charges excluding Delivery Point Charge ($/GJ) | Average Delivery Point charge for zone ($/GJ) | Total tariff ($/GJ) |
|---|---|---|---|
| Zone 1a | 0.0120 | 0.0047 | 0.0166 |
| Zone 4a | 9.2608 | 0.0519 | 9.3127 |
| Zone 6 | 0.4854 | 0.0114 | 0.4968 |
| Zone 7 | 0.5623 | 0.0701 | 0.6324 |
| Zone 9 | 0.7356 | 0.0432 | 0.7788 |
| Zone 10 (Kwinana industry and Rockingham laterals) | 0.8339 | 0.0116 | 0.8455 |
| Zone 10 (Pipeline South) | 0.8515 | 0.0393 | 0.8909 |

The Regulator notes that the above tariff has been calculated as an indicative Reference Tariff for the purposes of this Draft Decision. The Regulator has intentionally left Epic Energy with some discretion in determining how to go about meeting the Regulator's required amendments to the proposed Access Arrangement and Reference Tariff, and as such Epic Energy may propose a revised Reference Tariff that differs in some respects from that indicated above.

The following amendments are required before the proposed Access Arrangement will be approved.

Amendment 68

The Reference Tariff should be revised to reflect the required revisions to the Initial Capital Base, Capital Expenditure, Non-Capital Costs, Rate of Return and the Depreciation Schedule as described in this Draft Decision.

Amendment 69

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.

## 5.10 REFERENCE TARIFF VARIATION AND INCENTIVE MECHANISMS

### 5.10.1 Access Code Requirements

The Code addresses variation in Reference Tariffs over the Access Arrangement Period in terms of two general matters:

i. variation in Reference Tariffs at the discretion of the Service Provider and according to principles such as a predetermined price path or realised cost and sales outcomes for the Service Provider; and

ii. within the scope of (i), variation of Reference Tariffs according to principles of an Incentive Mechanism.

The provisions of the Code relating to these matters are outlined as follows.

**Variation in Reference Tariffs at the Discretion of the Service Provider**

Section 8.3 of the Code provides for the Service Provider to have discretion as to the manner in which Reference Tariffs vary across an Access Arrangement Period, subject to the Regulator being satisfied that such variation is consistent with the objectives for Reference Tariffs contained in section 8.1 of the Code. Section 8.3 of the Code goes on to indicate that, for example, a Reference Tariff may be varied across the Access Arrangement Period by means of:

(a) a price path approach, whereby a series of Reference Tariffs are determined in advance for the Access Arrangement Period to follow a path that is forecast to deliver a revenue stream calculated consistently with the principles in section 8 of the Code, but is not adjusted to account for subsequent events until the commencement of the next Access Arrangement Period;

(b) a cost of service approach, whereby the Tariff is set on the basis of the anticipated costs of providing the Reference Service and is adjusted continuously in light of actual outcomes (such as sales volumes and actual costs) to ensure that the Tariff recovers the actual costs of providing the Service; or

(c) variations or combinations of these approaches.

**Incentive Mechanism**

Sections 8.44 to 8.46 of the Code state the principles for establishing an Incentive Mechanism within the Reference Tariff Policy and the objectives that the Incentive Mechanism should seek to achieve.

Section 8.44 of the Code states that a Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism that permits the Service Provider to retain all, or a share of, any returns to the Service Provider from the sale of a Reference Service during an Access Arrangement Period that exceeds the level of returns expected at the beginning of the Access Arrangement Period (an Incentive Mechanism), particularly where 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.

Section 8.45 of the Code provides that 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 of the Code that provides for less than a full rebate of revenues from the Rebatable Services to the Users of the Reference Service.

Section 8.46 of the Code states that 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 of the Code; 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).

### 5.10.2 Access Arrangement Proposal

#### Reference Tariff Variation

Under section 7.14 of the proposed Access Arrangement and clause 16 of the Access Contract Terms and Conditions, Epic Energy makes provision for the Reference Tariff to be varied in three ways:

- pass through of the goods and services tax;
- annual adjustment in proportion to movements in the Consumer Price Index (CPI); and
- adjustment to take into account additional costs incurred by Epic Energy as a result of changes in the regulatory environment.

Provisions of the proposed Access Arrangement in each of these respects are as follows.

<u>Goods and Services Tax</u>

In sub-clause 16.3 of the Access Contract Terms and Conditions, Epic Energy propose that Shippers with contracts for the Reference Service pay, in addition to the Reference Tariff, an amount equal to the costs of any supply tax. This sub-clause intends to accommodate the imposition of the goods and services tax that was foreshadowed, but not implemented, at the time the proposed Access Arrangement was submitted to the Regulator.

<u>Annual CPI Adjustments</u>

In sub-clause 16.2 of the Access Contract Terms and Conditions, Epic Energy propose that on each 1 January (commencing in 2001) all of the charges of the Reference Tariff will be adjusted by 67 percent of the variation (expressed as a percentage) of the CPI for the 12 month period ending on the previous 30 September.

<u>Pass Through of Costs Arising from Changes in the Regulatory Environment</u>

Sub-clause 16.4 of the Access Contract Terms and Conditions makes provision for Epic Energy to apply to the Regulator for an adjustment of the Reference Tariff to accommodate additional costs incurred by Epic Energy during the Access Arrangement Period as a result of a change in the regulatory environment.

#### Incentive Mechanisms

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.

### 5.10.3 Submissions from Interested Parties

Submissions on the proposed Access Arrangement addressed the following issues in relation to variation in the Reference Tariff and incentive mechanisms.

- Pass through of the goods and services tax.
- Inflation indexation of the Reference Tariff.
- The price path approach to tariff setting as an incentive mechanism.

The submissions on each of these issues are summarised below together with the Regulator's response.

**Pass Through of the Goods and Service Tax**

Sub-clause 16.3 of the Access Contract Terms and Conditions makes provision for Epic Energy to pass on any goods and services tax liability incurred in provision of services to Users as a charge in addition to the Reference Tariff.

Treasury/Office of Energy submitted that the pass through of the goods and services tax should be subject to the approval of the Regulator, and that the pass through cost of the goods and services tax should reflect the net cost of tax changes associated with introduction of the goods and services tax.

The Regulator addressed the pass through of the goods and services tax in section 5.9.4 of this Draft Decision. The Regulator is of the view that it is appropriate to accommodate the pass through of the goods and services tax in the Reference Tariff, as it will be set out in the Access Arrangement, and will require Epic Energy to propose to the Regulator the rate of pass through of the goods and services tax. In view of this, the provisions of the proposed Access Contract Terms and Conditions relating to the pass through of a goods and services tax or other supply tax are considered to be redundant and the Regulator requires that the Access Contract Terms and Conditions be amended to remove the relevant sub-clause 16.3.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 70<br><br>The Access Contract Terms and Conditions should be amended to remove sub-clause 16.3 relating to the recovery of imposts and goods and services tax liabilities through charges levied on Users in addition to the Reference Tariff. |

**Inflation Indexation of the Reference Tariff**

Epic Energy has proposed that the individual charges of the Reference Tariff be escalated at a rate of 67 percent of the rate of change in the Consumer Price Index.

Worsley Alumina, AlintaGas,[289] Wesfarmers and North West Shelf Gas questioned the appropriateness of a general escalation of the Reference Tariff when most of the costs underlying the Total Revenue and tariff comprise sunk capital costs, and Epic Energy has

[289] AlintaGas Submission 3.

used a nominal Rate of Return in calculating the return on capital. WMC 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.

In response to these submissions, the Regulator notes that, 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.

In revising the Reference Tariff, the Regulator used the following steps in determining the tariff charges.

- Determination of the Total Revenue for each year of the Access Arrangement Period in real terms. That is, using a real rate of return on an unescalated Capital Base, and accounting for Non-Capital Costs in real values.
- Determination of the present value of Total Revenue for the Access Arrangement Period by discounting of the annual Total Revenues by a real discount rate.
- Determination of the Reference Tariff charges that would return the present value of Total Revenue over the Access Arrangement Period.

Under this tariff determination methodology, where tariffs are based on the present value of Total Revenue, 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.

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 considered appropriate. Compensating a pipeline Service Provider for inflation in Non-Capital costs is a different matter, as WMC has pointed out in its submission, as costs of providing pipeline services would not necessarily change at the same rate as an economy-wide measure of inflation. Notwithstanding this, the Regulator considers that inflation of tariffs in accordance with an economy wide measure of inflation is a reasonable methodology to use in the absence of an industry specific inflation measure. 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.

In regard to the implementation of an inflation escalation of tariffs, submissions from WMC, Worsley Alumina, AlintaGas,[290] and Western Power[291] expressed concerns as to the proposal by Epic Energy to use a proportion (67 percent) of the rate of change in the CPI as an escalation factor, without either justification or precedent for this choice of factor.

[290] AlintaGas Submission 3.

[291] Western Power Submission 3.

Submissions from CMS Gas Transmission, Treasury/Office of Energy, and Wesfarmers raised concerns over the use of either a proportion of a CPI change or a CPI–X value as an escalation factor. Treasury/Office of Energy and Wesfarmers indicated that a CPI-X value might be a more appropriate escalation factor as it incorporates an efficiency parameter (the X value) that is independent of the rate of inflation. CMS Gas Transmission stated an opposition to the indiscriminate application of a CPI–X escalation factor as an "efficiency incentive mechanism".

Finally, AlintaGas[292] and Treasury/Office of Energy submitted that the use of a CPI escalator should be treated with caution given that CPI is expected to be abnormally high in 2000/01 due to the introduction of the goods and services tax from 1 July 2000.

As far as the Regulator has been able to ascertain, the choice by Epic Energy to use an escalation factor of 67 percent of the rate of change in the CPI was largely arbitrary. In view of this, the Regulator has given attention to escalation of the revised Reference Tariff as set out in section 5.9.4 of this Draft Decision.

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.

While a tariff path involving inflation of the Reference Tariffs at a rate of 67 percent of the change in the Consumer Price Index (CPI) has been assumed, as proposed by Epic Energy, this relates only to determination of a smooth tariff path and <u>not</u> the extent to which Epic Energy is compensated for inflation. This allows Epic Energy to recover the full cost of service over the regulatory period and fully compensates Epic Energy for effects of forecast inflation.

The Regulator considers that for the purpose of annual tariff adjustments, the most appropriate inflation measure is 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. The Regulator is also of the view that the CPI measure used for the inflation escalation of the Reference Tariff should be exclusive of the inflationary effect of the goods and services tax. The Regulator's preferred method for adjusting for the inflation effects of the goods and services tax is to correct the CPI measure by a forecast of the inflationary effect previously made by the Commonwealth Treasury of 2.75 percent of the CPI.

The following amendment is required before the proposed Access Arrangement is approved.

[292] AlintaGas Submission 3.

Amendment 71

The proposed Access Arrangement should be amended to provide for annual escalation of Reference Tariff charges on the basis of 67 percent of the annual rate of change in the Eight Capital City, All-Groups Consumer Price Index as published by the Australian Bureau of Statistics and not the All-Groups Perth measure as proposed by Epic Energy. In escalating the Reference Tariff for 2001, the CPI for 2000 should be reduced by 2.75 percent of the CPI to account for the inflationary impact of the goods and services tax.

**Incentive Mechanisms**

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 the sale of Non-Reference Services.

Provisions of the proposed Access Arrangement relating to Rebatable Services were addressed by the Regulator in section 5.9.3.10 of this Draft Decision. Submissions on the more general incentive mechanism of the price path approach to Reference Tariff determination are addressed below.

In regard to the price path approach to the setting of tariffs, Treasury/Office of Energy cited sub-clause 2.6 of the Access Arrangement Information that states "if Epic Energy is able to increase demand for the Reference Service above the forecast quantities used in tariff determination, its revenue from sales will exceed the forecast revenue. To the extent that the increase in demand can be accommodated without a proportionate increase in cost, Epic Energy will generate higher than expected profits. These higher profits are retained at least until the end of the Access Arrangement Period." Treasury/Office of Energy indicated that the above statement might be taken to imply that the benefits of that increased demand and thus higher profits will then be shared with Users in the subsequent Access Arrangement Period. However, under the general thrust of the proposed Access Arrangement, including the concept of the deferred recovery account and the predetermined "tariff path", it is more likely that those profits will be used to reduce the "deferred recovery account". Treasury/Office of Energy suggest that it would be more appropriate that this is transparently stated in the Access Arrangement Information.

The concerns of Treasury/Office of Energy in regard to the incentive mechanisms proposed by Epic Energy relate to the relationships with Epic Energy's proposed deferred recovery account. The Regulator notes that under the revised Reference Tariff as set out in this Draft Decision, there is no deferred recovery of costs.

### 5.10.4 Additional Considerations of the Regulator

**Pass Through of Costs Arising from Changes in the Regulatory Environment**

In addition to escalation for inflation and pass through of the goods and services tax, the proposed Access Arrangement (sub-clause 16.4 of the Access Contract Terms and Conditions) makes provision for Epic Energy to apply to the Regulator for an adjustment of the Reference Tariff to accommodate additional costs incurred by Epic Energy as a result of a change in the regulatory environment.

The Regulator is of the view that the Code does not provide for Reference Tariffs to be altered other than through a review of the Access Arrangement. This is because the Code itself provides only for the Regulator to be involved in approving proposed Access Arrangements and revisions to existing Access Arrangements. The Regulator therefore notes that while Epic Energy may apply at any time for an adjustment of the Reference Tariff the process for application, and for the Regulator's consideration of the application, would be a review of the Access Arrangement in accordance with the relevant provisions of the Code.

# 6 FEES AND CHARGES OTHER THAN THE REFERENCE TARIFF

## 6.1 ACCESS ARRANGEMENT PROPOSAL

The proposed Access Arrangement provides for Epic Energy to levy a range of fees and charges on Users and Prospective Users of services. These fees and charges (referred to collectively as penalty charges) are as follows:

- Prescribed Fee for an Access Request

  Paragraph 5.1(c) of the proposed Access Arrangement requires that a Prescribed Fee of $5,000 accompany an Access Request for a service.

- Out of Specification Gas Charge

  Paragraph 2.4(c) of the Access Contract Terms and Conditions provides for a Shipper to be liable to pay a surcharge of $15 for each gigajoule of out of specification gas.

- Nomination Surcharge

  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.

- Overrun Charge

  Sub-clause 5.2 of the Access Contract Terms and Conditions provides for a Shipper to pay Overrun Charges in certain circumstances where the quantity of gas delivered to a Shipper exceeds that Shipper's MDQ. The Overrun Charge comprises:

  – 110 percent of additional Capacity Charges where Overrun at one Delivery Point is deemed to constitute a relocation of capacity to a Delivery Point in a pipeline zone downstream of the Delivery Point at which the Overrun occurs (paragraph 5.2(a)(ii) of the Access Contract Terms and Conditions);

  – the greater of 110 percent of the Capacity Charges and Gas Receipt Charges or the highest price paid on the Secondary Market for the day in which the Overrun occurs in the event that the aggregate quantity of gas delivered to a Shipper exceeds the Shipper's aggregate MDQ (paragraph 5.2(b) of the Access Contract Terms and Conditions).[293]

[293] The Regulator notes that the example given for calculation of Overrun Charges immediately after paragraph 5.2(b) of the Access Contract Terms and Conditions indicates that the Overrun Charge may be calculated as 110 percent of the sum of Capacity Charges and Compressor Fuel Charges, which is contrary to the statement in paragraph 5.2(b)(i) which states that the Overrun Charge may be calculated as 110 percent of

- Excess Imbalance Charge

  Sub-clause 6.4 of the Access Contract Terms and Conditions provides for a Shipper to pay an Excess Imbalance Charge where the Shipper's Imbalance at the end of a day exceeds the Shipper's Imbalance Limit, which is two percent of the Shipper's MDQ. The Excess Imbalance Charge is levied at a rate of $15 for each gigajoule by which the absolute value of the Shipper's Imbalance exceeds the Imbalance Limit.

- Peaking Surcharge

  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.

- Unavailability Charge

  Sub-clause 5.4 of the Access Contract Terms and Conditions provides for Epic Energy to charge a Shipper an Unavailability Charge of $15 of each gigajoule of gas delivered to the Shipper at a Delivery Point, or in aggregate as the case may be, in excess of a quantity specified for that Shipper in a relevant Unavailability Notice. An Unavailability Notice would be issued to a Shipper where, for one reason or another, Epic Energy deemed it necessary to restrict the delivery of gas to a Delivery Point.

## 6.2 SUBMISSIONS FROM INTERESTED PARTIES

### 6.2.1.1 Overview of Submissions

Submissions to the Regulator on the proposed Access Arrangement addressed the following matters in relation to fees and charges:

- The reasonableness of the Prescribed Fee for an Access Request.
- The provision for and general level of charges and surcharges.
- The reasonableness of proposed imbalance limits.
- The Nomination Surcharge.
- The Overrun Charge.
- The Peaking Surcharge.
- The rebate of revenue derived from penalty charges.

Submissions in respect of each of these matters are summarised below together with the Regulator's responses to the matters raised.

### 6.2.1.2 Prescribed Fee for an Access Request

Robe River Mining submitted that the proposed Prescribed Fee of $5,000 seems unreasonable, especially in situations where the Access Request if for a service such as a single-day spot service.

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the sum of Capacity Charges and Gas Receipt Charges. For the purposes of this Draft Decision, the Regulator has considered the calculation of the Overrun Charge as described in paragraph 5.2(b)(i), but draws Epic Energy's attention to this apparent discrepancy.

In assessing whether the Prescribed Fee is a reasonable practice on the part of Epic Energy, the Regulator considered 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.

The Regulator notes that section 5.5 of the Code specifically provides for a Service Provider to recover costs incurred in undertaking any investigations for the purposes of ascertaining whether an Access Request can be met. These costs may be recovered from the relevant Prospective User through charges in addition to any charges specifically provided for in the proposed Access Arrangement.

The Regulator is of 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, the Regulator notes that the levying of a fee such as the Prescribed Fee is not common industry practice in the gas transmission industry.[294]

The Regulator does, however, accept that some costs are incurred in the normal course of assessment of access requests, but considers that an application fee should not exceed $1,000.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 72<br><br>Clause 5.1 and the definitions of the proposed Access Arrangement should be amended such that the Prescribed Fee to accompany an Access Request is of an amount no greater than $1,000. |

The Regulator notes the concern raised by Robe River Mining 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. The Regulator considers 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.

The following amendment is required before the proposed Access Arrangement will be approved.

[294] 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 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.

Amendment 73

The proposed Access Arrangement should be amended to 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 arrangements.

### 6.2.1.3 General Levels of Penalty Charges

Epic Energy has proposed unit rates of penalty charges of $15/GJ in relation to the Out of Specification Gas Charge, the Nomination Surcharge, the Excess Imbalance Charge, the Peaking Surcharge, and the Unavailability Charge. Submissions from Western Power,[295] Apache Energy Limited, Worsley Alumina, Robe River Mining, WMC, North West Shelf Gas, AlintaGas,[296] Hamersley Iron and CMS Gas Transmission expressed a view that the level of these penalty charges is unreasonably high and punitive. Several of these submissions expressed the view 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.

North West Shelf Gas submitted that the high level of penalty charges would cause Users to book high levels of capacity to avoid liability for the charges, leading to higher costs for the Users and inefficient use of pipeline capacity.

AlintaGas and Western Power submitted that it might not be legal for the Access Arrangement to include proposed charges for the reason that a contractual clause that purports to impose a penalty is unlawful. According to AlintaGas:

> A clause is a penalty if it is included in a contract to coerce a party into complying with the party's obligations under the contract. A clause is likely to be a penalty if it is not a genuine pre-estimate of damage. A court of law is likely to view a clause as a penalty if the sum stipulated is extravagant and unconscionable in amount in comparison with the greatest loss that could conceivably be proved to have followed from the breach. A charge of about 15 times the full-haul delivery price is likely to satisfy such a test.
>
> Further, a contractual provision will be presumed to be a penalty when a single lump sum is made payable by way of compensation, on the occurrence of one or more or all of several events, some of which may occasion serious and others but trifling damage. The fact that the proposed rates and charges in Schedule 1 to the Terms and Conditions are all set at the same level suggests they are arbitrary and punitive.

Western Power submitted that:

> The surcharges would appear to bear little relationship to any potential cost impacts. Some surcharges would appear to be structured as deterrent penalties only, rather than aimed at cost recovery.
>
> If the surcharges are intended to be deterrents, they are likely to be unlawful penalties. If the surcharges are not intended to be deterrents, then each surcharge should reflect the cost of remedying the effects of the relevant breach. Western Power considers this to be a significant issue and much more information is needed before the matter can be considered by all parties.
>
> The following are indications that a clause is a penalty:
>
> - It is included in the contract to coerce one party to comply with its obligations – this is certainly the case for the nominations penalty, because there is already an obligation to nominate in good faith;

[295] Western Power Submissions 4 and 5.

[296] AlintaGas Submission 3.

- It is not a genuine pre-estimate of damage – the fact that all the penalties in Schedule 1 are set at the same level of that 1500% of the Zone 9 full-haul tariff (and many times that again, for part-haul contracts) strongly suggests that they meet this requirement; and
- A single amount being payable for more than one event, where such events would be expected to result in different levels of damage, this is the case with Schedule 1.

Western Power further submitted that an important consideration in assessing the reasonableness of proposed penalty charges is that the pipeline operator has the capacity to curtail gas delivery before any additional gas delivery costs of any substantial scale are incurred.

Epic Energy[297] submitted that while noting statements by the Regulator in the Draft Decision on the Parmelia Pipeline Access Arrangement (and on the AlintaGas Distribution Systems Access Arrangement) regarding the quantum of penalty charges, in which the Regulator made observations of common practice of charges being in the order of 350 percent of relevant Reference Tariffs, Epic Energy does not believe that the amount of $15/GJ is out of the ordinary. While rates have tended to be around the 350 percent mark in Australia, penalty rates for systems in USA tend to be much higher and it is not unusual to find penalty rates, proportionally, in the order proposed for the proposed Access Arrangement.

Epic Energy also submitted that in respect of the purpose of the penalty charges:

> The imposition of surcharges in the situations proposed in the Access Arrangement is directed at correcting behavioural attitudes to ensure all users of the system get the maximum benefit available. It is not an issue of cost recovery as appears to have been accepted by the Regulator in the draft decision for the Parmelia Pipeline Access Arrangement. Generally the matters addressed by such surcharges are to deal with breaches Epic Energy can only become aware of after they have occurred and is not able to take preventative action. That aspect coupled with the general reluctance amongst pipeline operators to shut off gas supply to a breaching Shipper, dictates the importance and need for higher amounts to deter unsatisfactory behaviour.

Epic Energy also addressed the issue of the legality of the penalty charges.

> The questions raised about the legality of charging the surcharge have not been detailed. In order to avoid any legal issues the Regulator may consider requiring the Access Arrangement to be modified so that the Shipper is obliged to use its best endeavours to not exceed the relevant requirement and that the Shipper has a right to exceed that requirement, but if it does a surcharge will be payable.

In assessing the reasonableness of the general level of the proposed penalty charges, the Regulator gave consideration to common practice of the gas transmission industry in respect of such charges. A summary of the magnitude of relevant charges in Access Arrangements or proposed Access Arrangements for other pipelines is as follows.

[297] Epic Energy Submission 7.

**Magnitudes of penalty charges under approved or proposed Access Arrangements for transmission pipelines**

| Pipeline | Penalty Action[298] | Penalty Charge as multiple of Relevant Reference Tariff |
|---|---|---|
| Amadeus Basin to Darwin (N.T. Gas Pty Ltd) | Daily overrun | 2 |
| | Imbalance | 2.5 |
| | Nomination variance | 1.2 |
| Central West Pipeline (AGL Pipelines (NSW) Pty Ltd) | Daily overrun | 2 or 3 |
| | Imbalance | 2.5 |
| | Nomination variance | 1.2 |
| Moomba to Sydney Pipeline (East Australian Pipeline Limited) | Daily overrun | 4.5 |
| Moomba to Adelaide Pipeline (Epic Energy) | Hourly overrun (peaking charge) | 1.75 |
| | Daily overrun | 1.75 |
| | Imbalance | 0.70 (approx.) |
| Mildura Pipeline (Envestra) | Daily overrun | 5 (approx.) |
| Tubridgi Pipeline System (Tubridigi Parties) | Daily overrun | 1.25 |
| Goldfields Gas Pipeline (Goldfields Gas Transmission) | Hourly overrun (peaking charge) | 3.5 |
| | Daily overrun | 3.5 |

With the exception of the imbalance charge for the Moomba to Adelaide Pipeline, penalty charges for transmission pipelines are observed to be in the range of 1.2 to 5 times the value of the relevant Reference Tariff, with an average of about 2.5. It is thus noted that the penalty rates proposed by Epic Energy for the Out of Specification Gas Charge, Nomination Surcharge, Excess Imbalance Charge and Peaking Surcharge ($15/GJ or 15 times the proposed Reference Tariff) are substantially in excess of what may be regarded as reasonable on the basis of common practice in the industry. On this basis, the Regulator considers that the rates of these penalty charges should be reduced. Taking into account the earlier decision in relation to penalty charges for the Parmelia Pipeline,[299] the Regulator will require the rates of penalties to be reduced to a maximum of 350 percent of the relevant Reference Tariff.

The following amendment is required before the proposed Access Arrangement will be approved.

[298] For ease of comparison, penalty actions are described by the relevant terms as used in the proposed Access Arrangement for the DBNGP rather than, necessarily, the terms used in the Access Arrangement for the relevant pipeline.

[299] Independent Gas Pipelines Access Regulator Western Australia, 20 October 2000, Final Decision on the Parmelia Pipeline Access Arrangement.

| |
|---|
| Amendment 74<br><br>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. |

The Regulator notes that the proposed Unavailability Charge of $15/GJ has no precedent in other pipelines with the exception of Epic Energy's Moomba to Adelaide Pipeline for which a curtailment charge of $75/GJ is provided for in the proposed Access Arrangement for that pipeline. The Regulator notes that 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 that liability for the charge would only arise after issue to the User of an Unavailability Notice. Further, 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, the Regulator does not oppose the proposal for the Unavailability Charge.

The Regulator has not addressed in any detail the issue of legality of the proposed penalty charges but notes that charges as proposed by Epic Energy, as required to be revised by the Regulator, are common practice in the gas transmission industry.

#### 6.2.1.4 Out of Specification Gas Charge

Epic Energy has proposed an Out of Specification Gas Charge which is levied at a rate of $15 for each gigajoule of out of specification gas.

Treasury/Office of Energy questioned whether this charge would apply to gas actually delivered by Epic Energy. In addition, Treasury/Office of Energy also commented that penalising for gas that is vented by Epic Energy does not seem appropriate.

The Regulator notes that paragraph 2.4(c) of the Access Contract Terms and Conditions (relating to a User's liability for out of specification gas) makes it clear that the Out of Specification Gas Charge relates to gas entering the DBNGP, and hence would apply to Out of Specification Gas regardless of whether this gas is delivered or vented.

The Regulator notes that the Out of Specification Gas Charge is of the nature of a penalty, with the implied purpose of discouraging supply of out of specification gas to the DBNGP. As such, the Regulator does not consider it inappropriate for the charge to apply. The Regulator is, however, requiring that the level of the Out of Specification Gas Charge be reduced (Amendment 74).

#### 6.2.1.5 Imbalance Limit and Charges

Epic Energy has proposed 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 a daily Imbalance Limit of two percent of the Shippers MDQ.

Several submissions addressed the proposed Imbalance Limit and Excess Imbalance Charge.

AlintaGas[300] submitted that 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). Western Power[301] submitted that penalties for positive imbalances are unjustified:

> In proposing new imbalance tolerance limits and surcharges for the DBNGP, Epic Energy has failed to recognise the different consequences on the DBNGP arising from positive and negative imbalances. The implication of a positive imbalance is that the pipeline operator is able to use Shippers' imbalance gas as linepack and/or compressor fuel. This is in contrast to the situation of a Shipper having a negative imbalance, whereby that Shipper is borrowing gas from the linepack, probably created by other Shippers' positive imbalances.

Western Power[302] also submitted in relation to the Excess Imbalance Charge that the key criterion in setting any surcharge should be the operational impact of Shipper imbalances on the DBNGP, and pointed out that the overall state of imbalance on the DBNGP should be the paramount focus, not whether a particular individual Shipper is out of balance.

Submissions from North West Shelf Gas, Treasury/Office of Energy, Western Power,[303] WMC, Robe River Mining, Chamber of Commerce and Industry, South West Development Commission, Chamber of Minerals and Energy, Cockburn Cement … expressed concern in regard to the proposed Imbalance Limit of two percent of a User's MDQ, indicating that this limit 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. Several of these submissions also made reference to an eight percent limit as an industry standard.

Submissions from Western Power,[304] and Treasury/Office of Energy indicated that the provision for the Excess Imbalance Charge potentially provides for Users to be liable to the charges where an imbalance is caused by actions of Epic Energy in curtailing gas receipt or delivery, or the actions of another User. Western Power submitted that 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 the clause 184(2) of the *Gas Transmission Regulations 1994*.

Western Power[305] expressed concern that Users were 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.

Western Power,[306] and Hamersley Iron and made reference to balancing provisions that 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, and which purportedly operate to the benefit of Epic

[300] AlintaGas Submission 3.
[301] Western Power Submission 5.
[302] Western Power Submission 5.
[303] Western power Submission 5.
[304] Western Power Submission 5.
[305] Western Power Submission 5.
[306] Western Power Submissions 2, 5.

Energy and foster the efficient operation of the DBNGP, but which could give rise to liabilities to the Excess Imbalance Charge.

Epic Energy[307] responded to these submissions as follows.

> 2.2 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 2 per cent 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.
>
> 2.3 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 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.
>
> 2.4 The fact that the proposed DBNGP Access Arrangement does not allow Shippers to trade imbalances has been recognised by Epic Energy. Epic Energy is prepared to propose amendments to permit Shippers to trade imbalances.
>
> 2.5 WMC Resources has compared the imbalance tolerance proposed for the DBNGP with the imbalance tolerances on other transmission pipelines:
>
> > *"At just 2%, the allowance for imbalance is much less than is allowed on other transmission pipelines (where up to 8% is allowed and some accumulation is also possible). The Goldfields Gas Pipeline offers much greater tolerances and a more acceptable penalty regime than is offered by the DBNGP proponents."*
>
> 2.6 Epic Energy can equally point to examples in the USA where tolerances are 2% [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.
>
> Epic Energy has commented on the proposed excess imbalance charge in Epic Submission 7.
>
> Epic Energy notes the comments regarding no provision for trading imbalances. That omission was not intentional (and one in which the Secondary Market could have a role) and therefore would not be averse to a requirement to include such a provision.

The Regulator is 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 as potentially serious in terms of impacts on pipeline operation as negative imbalances, may affect the ability of other Users to deliver gas to the pipeline. The Regulator does, however, note that 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.

The Regulator notes that 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

[307] Epic Energy Submission 6.

for surcharges, while high imbalance limits may 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 largely arbitrary limit reflecting a particular, but not necessarily in any way superior, balancing of interests of the Service Provider and Users.

That said, the Regulator has 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, the Regulator notes that 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.

The Regulator also notes 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.

In addition, Epic has the right to refuse the acceptance of gas into the pipeline and to refuse gas delivery to the User (section 6.5 of the Access Contract Terms and Conditions). Imbalance charges should be viewed as an incentive for Users to be in balance rather than as a means of maintaining system integrity.

In view of the above, the Regulator considers that the proposed imbalance limit of two percent of a User's MDQ is unreasonable. The Regulator will require the proposed Access Arrangement to be amended to provide for an imbalance limit of eight percent of a User's MDQ.

The Regulator recognises the concerns raised in submissions in regard to the limited ability of Users to manage potential liability to the Excess Imbalance Charge. In this regard, the Regulator notes the requirement of Amendment 11 (section 4.3.3 of this Draft Decision) for the proposed Access Arrangement to be amended to allow for re-nominations over the course of a day. The Regulator will also require the proposed Access Arrangement to be amended to provide for the timely availability to Users of information necessary for the assessment of potential liabilities for penalty charges (section 4.2.3 and Amendment 5 of this Draft Decision), and to provide Users with an ability to trade imbalances.

The following amendments are required before the proposed Access Arrangement will be approved.

| |
|---|
| Amendment 75<br><br>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 76<br><br>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 77<br><br>The proposed Access Arrangement should be amended to provide for Users to trade imbalances and thereby reduce potential liabilities to the Excess Imbalance Charge. |

The Regulator has given attention to the submissions indicating that special provisions for balancing exist in relation to the delivery of gas to Delivery Points in the Pilbara region. The Regulator notes that these provisions will persist for the term of the relevant contracts rather than necessarily being negated by the Access Arrangement. The Regulator sees no reason, however, to make such provisions part of the terms and conditions for the Reference Service. The Regulator notes that, 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.

### 6.2.1.6 Nomination Surcharge

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 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, and 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.

Submissions received on the proposed Nomination Surcharge are as follows.

- Hamersley Iron

  Paragraph 4.4(c) of the Access Contract Terms and Conditions imposes a Nomination Surcharge of $15/GJ - this is likely to have a substantial impact on the overall tariffs payable and represents a penalty which is approximately 2,100 times the capacity reservation charge Hamersley pays under the *Gas Transmission Regulations 1994*. It is approximately 150 times the proposed Reference Tariff that would apply to Hamersley as a Zone 1a Shipper. Hamersley submits that the penalty imposed by the Nomination Surcharge is not commercially reasonable.

- Western Power Submission 5

  A new nomination penalty of $15/GJ may be imposed in some circumstances under the Firm Service. The imposition of $15/GJ penalty on every gigajoule of a nominations inaccuracy, not just the gigajoules in excess of the 10% threshold, seems impossible to justify on cost-recovery grounds.

  To a significant extent, variations in Western Power's gas usage within a gas day (such as might cause gas consumption to depart from nomination levels) are driven by customer load, and on occasions, by unplanned outages of generation units. Both of which are factors not within Western Power's immediate control. The imposition of very large nomination penalties is unfair in this circumstance.

  The inability to make renominations during the gas day will limit Shippers' ability to optimise gas deliveries and remain within the 2% imbalance tolerance.

> Western Power requests the Regulator to require Epic Energy to adopt an equitable regime for nomination surcharges.

In response to the matters raised in submissions in respect of the value of the Nominations Surcharge and the ability to make re-nominations during a day, the Regulator refers the reader to the discussion of the general level of penalty charges (p. 279 of this Draft Decision) and to the assessment of terms and conditions for the provision of the Reference Service (section 4.3 of this Draft Decision). The Regulator is requiring amendments of the proposed Access Arrangement to reduce the rate of the Nominations Surcharge and to allow for re-nominations during a gas day.

In regard to Western Power's expressed concern as to the potential liability of a User to the re-nominations surcharge where that User's delivery of gas is not predictable with accuracy, the Regulator notes that a User may only become liable for the Nominations Surcharge after a Variance Notice has been issued, and only where Epic Energy might reasonably believe that nominations were not made in good faith. The Regulator is of the view that in forming a reasonable opinion as to whether a User has nominated in good faith, a necessary consideration would be the ability of the User to predict with accuracy the delivery of gas for the relevant day. In view of this, and in view of the Regulator's required amendment of the proposed Access Arrangement to allow re-nominations within a gas day, the Regulator is satisfied that Users would not unreasonably be held liable to the Nominations Surcharge. It is noted that the Regulator has elsewhere required that the value of the nominations surcharge is required to be reduced to a maximum of 350 percent of the 100 percent load factor Reference Tariff (Amendment 74).

#### 6.2.1.7 Overrun Charge

Sub-clause 5.2 of the Access Contract Terms and Conditions provides for a Shipper to pay Overrun Charges in certain circumstances where the quantity of gas delivered to a Shipper exceeds that Shipper's MDQ.

The following submission was received in relation to the proposed Overrun Charge.

- Western Power Submission 5

  The overrun penalties ($15/GJ) proposed for the Firm Service are excessive when compared to the existing situation for the DBNGP, whereby Epic Energy may make interruptible full-haul capacity available at the AT3 level ($1.15/GJ), or at 105% - 110% of the T1 price for part haul (i.e. authorised/unauthorised service surcharge).

The Regulator notes that 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 Regulator notes that 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. Finally, the Regulator notes that the proposed Overrun Charge is calculated as either 110 percent of relevant capacity charges, or 110 percent of the highest price for capacity on the Secondary Market for the relevant day, and not the $15/GJ referred to by Western Power. The proposed magnitude of the Overrun Charges is considered by the Regulator to be reasonable.

#### 6.2.1.8 Peaking Surcharge

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.

Submissions received on the proposed Nomination Surcharge were as follows.

- Western Power Submission No. 1

  Peaking Regime

  It is unclear how the proposed peaking regime would be implemented for Zone 4A, as the Carnarvon Lateral is operated effectively as a pressure vessel separate from the DBNGP.

- Western Power Submission 5

  The Firm Service seeks to impose $15/GJ peaking penalties on a daily and hourly basis; whereas peaking penalties have not previously been required. The proposed peaking penalties would apply to every hour that the Shippers' gas demands exceeds 120% of 1/24 of the Shippers' MDQ (i.e. MHQ) at each Delivery Point.

  It appears that unlike the position under the GTR contracts, Shippers will not be able to aggregate peaking imbalances across multiple receipt and Delivery Points.

- Treasury/Office of Energy

  The proposed permissible hourly peak is 120% of 1/24 of the daily total.

  The Regulator would need to consider if the permissible hourly peak is appropriate.

Epic Energy[308] responded to submissions relating to the proposed Peaking Surcharge acknowledging that the peaking limit proposed is somewhat tighter than the current winter limit, but indicating that peaking limits were set using pipeline simulation modelling to determine perturbations that can be sustained, given current operating conditions, without impairing delivery capability.

The Regulator notes that charges such as 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. Further, 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. As such, the Regulator considers that Epic Energy's proposed provision for a peaking surcharge and the proposed peaking limit are reasonable.

The Regulator notes, however, that Epic Energy has proposed to apply the peaking limit to individual Delivery Points. The Regulator considers that for the DBNGP, this is an unreasonable restriction and the peaking limit should apply in aggregate across all of a User's Delivery Points within each pipeline zone.

The following amendment is required before the proposed Access Arrangement will be approved.

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| Amendment 78<br><br>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. |

[308] Epic Energy Submission 6.

The Regulator also notes that the proposed magnitude of the Peaking Surcharge is considered to be unreasonable and the Access Arrangement is required to be amended to reduce the level of the charge (Amendment 74).

#### 6.2.1.9 Rebate of Penalty Revenues

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 for any other penalty charges to be treated as Rebatable Revenue.

AlintaGas[309] submitted 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.

Submissions from Chamber of Commerce and Industry and Cockburn Cement questioned the disposition of revenue from penalty charges, but did not state a position on the manner in which this revenue should be treated.

Epic Energy[310] 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.

The Regulator has noted the actual or proposed practice of several other Australian transmission pipelines for revenues gained by imbalance and/or Overrun penalties to be rebatable.[311] The Regulator considers that is a reasonable practice where the forecast revenue from the penalties is not considered in the determination of Reference Tariffs, as is the case for the DBNGP. The Regulator therefore requires that the proposed Access Arrangement be amended to provide for revenue from penalty charges to be rebatable as if the activities or events to which penalty charges relate were Rebatable Services within the meaning of the Code and section 9 of the proposed Access Arrangement.

In regard to the treatment of penalty revenues as Rebatable Revenues, the Regulator notes that 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, the Regulator considers that it is appropriate that the rebate mechanism established for penalty revenues provide for 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, the Regulator considers that rebate of 95 percent of penalty revenue would be appropriate. The Regulator notes that the provisions contemplated here for rebate of revenues from surcharges

[309] AlintaGas Submission 3.

[310] Epic Energy Submission 7.

[311] 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.

differ from the provisions of the proposed Access Arrangement in relation to rebate of revenue of Non-Reference Services.

The following amendment is required before the proposed Access Arrangement will be approved.

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|---|
| Amendment 79<br><br>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. |

### 6.3 ADDITIONAL CONSIDERATIONS OF THE REGULATOR

Other than matters addressed in response to public submissions, the Regulator has no concerns with fees and charges in addition to the Reference Tariff.

# 7 OTHER MATTERS RAISED IN PUBLIC SUBMISSIONS

## 7.1 OVERVIEW

There were two issues addressed by submissions that do not relate to matters required under sections 3.1 to 3.20 of the Code to be addressed in an Access Arrangement. These are:

- the disposition of existing contracts entered into under the *Gas Transmission Regulations 1994* or *Dampier to Bunbury Pipeline Regulations 1998*; and
- interconnection of the DBNGP with other gas transmission pipelines.

The submissions on these issues are summarised below together with the Regulator's responses.

## 7.2 DISPOSITION OF EXISTING CONTRACTS

Submissions on the proposed Access Arrangement raised concerns in regard to both the prospect for existing contracts to be translated into contracts for services under the proposed Access Arrangement, and the protection of existing contractual rights.

Western Power[312] submitted that the proposed Access Arrangement is deficient inasmuch as it does not describe the manner in which existing contracts are to be phased into the proposed Access Arrangement. In a further submission, Western Power[313] suggested that the Regulator consider whether Grandfathered Contracts must have access to a full range of Reference Services to ensure that equitable negotiations could be conducted, and whether the Access Arrangement must ensure that existing obligations and rights under the Gas Transmission Regulation Contracts are preserved.

AGL submitted that under the proposed Access Arrangement, Users of the DBNGP that hold existing contracts under the *Gas Transmission Regulations 1994* or *Dampier Bunbury Pipeline Regulations 1998* may face terms and conditions more onerous than those currently applying, including higher charges for gas transmission. AGL requested that the Regulator provide certainty for existing Shippers that current terms and conditions will not be adversely affected under the Access Arrangement. On a similar note, Robe River Mining drew attention to paragraph 6.1(b)(ii) of the proposed Access Arrangement that states that Non-Reference Services are also to include services provided by Epic under Grandfathered Contracts. Robe River Mining requested that the Regulator consider the implications of this for the purposes of Section 2.24 (b) and 2.25 of the Code and be satisfied that approval of this provision will not deprive holders of Grandfathered Contracts of any pre-existing contractual rights (e.g. options for term extensions), and require inclusion in the Access Arrangement of sufficient information regarding Grandfathered Contracts so that the Regulator is in a position to make an assessment as to whether or not approval of the proposed Access Arrangement will deprive holders of pre-existing contractual rights.

Several other submissions raised questions of how certain existing contractual rights would be accommodated under the Access Arrangement, as follows.

- Worsley Alumina

  The Queuing Policy does not appear to guarantee continuity of access for existing Users. Projects that require gas for the long term require continuity of supply but, in the face of uncertainty in their own

[312] Western Power Submission 3.

[313] Western Power Submission 6.

markets, only enter "take or pay" contracts for the minimum term that balances the risk between the user and the pipeline owner. Existing Users should be able to expect "right of first refusal" over their contracted capacity, but this does not appear to be acknowledged in the queuing policy. Note that this policy refers to "existing and new" users collectively.

- Wesfarmers Ltd

  The queuing policy does not guarantee continuity of access for existing users.

- Western Power Submission 3

  Western Power was a foundation Shipper on the DBNGP. It has previously been led to believe that costs would decrease as reservation charges were discharged and delivery quantities increased. To the extent that costs do decrease, Western Power believes that it (with other foundation Shippers on the DBNGP) has a right to expect an opportunity to participate in that decrease.

- Western Power Submission 5

  It appears that Shippers with GTR contracts will not have the same trading entitlements as Firm Service Shippers in the Secondary Market.

  Western Power questions how Epic Energy can provide access to spare capacity to Shippers with GTR contracts, while operating a Secondary Market for eligible Shippers.

  Western Power submits that Epic Energy should not be allowed to implement the proposed market trading regime, which effectively removes the rights of GTR Shippers to have access to daily interruptible capacity, unless the GTR Shippers are eligible to purchase and sell capacity in the Secondary Market, and the Secondary Market rules are less restrictive."

- WMC

  We believe that existing holders of transportation contracts should be given a once only opportunity to make any adjustments to their contracted quantities which they deem necessary to enable them to adjust to the new Terms and Conditions once finalised by O*ff*GAR.

Epic Energy responded to these submissions as follows.

- Epic Energy Submission 9

  9.2.1 Epic Energy rejects the suggestion that the grandfathered contracts have any special rights other than the requirements for Epic Energy to comply with section 20 of the Dampier to Bunbury Pipeline Act 1997. That in itself is unusual, but to suggest that existing users should have some special rights to capacity for as long as they want it or that they can pick and choose from the Access Arrangements those bits that they like is unacceptable and has no basis.

  9.2.2 The existing contracts are what they are and no cogent argument has been put as to why they should have any of these special rights. It has not happened anywhere else and there is no basis for it happening here. Those parties entered into contracts with the then Service Provider, AlintaGas, on the basis and for the term that they accepted. By the same token Epic Energy acquired the DBNGP with those contracts and had to accept its lot in that respect.

  If these Shippers want certainty as to capacity in the future, they should contract for it. If they want some or all of the terms in the Access Arrangement they should approach Epic Energy and seek to negotiate those changes. Epic Energy has stated before and states again it will be receptive to Shippers wanting to change their contract to Access Arrangement terms and conditions. If they wish to participate in the Secondary Market then they should approach Epic Energy to negotiate how that might be done. Otherwise there are no special privileges for these contracts.

The disposition of existing contracts for gas transmission was discussed in section 2.4 of this Draft Decision. As noted in that section, existing contracts are not affected in their continuance or operation by the Code.

Notwithstanding the continuance of existing contracts, Epic Energy might, after approval of the Access Arrangement, be obliged to offer to vary the price for services under existing contracts to the Reference Tariff for the Firm Service. Whether or not this obligation exists depends in part on whether the Firm Service is considered to be equivalent to the existing T1 Service and/or T2 Service. A decision on this matter is outside of the jurisdiction of the

Regulator. However, the Regulator notes that the Firm Service when amended in accordance with the requirements of this Draft Decision, and when offered in combination with the Non-Reference Services set out in Epic Energy's proposed Services Policy, is similar to the T1 Service.

## 7.3 INTERCONNECTION OF TRANSMISSION PIPELINES

North West Shelf Gas expressed concern that the proposed Access Arrangement does not make provision for a Delivery Point from the DBNGP to the Goldfields Gas Pipeline and requested that the Regulator require Epic Energy to make allowance for such a Delivery Point in the Access Arrangement.

Epic Energy responded to this submission as follows.

- Epic Energy Submission 9

> The question of whether a Delivery Point is provided is not a matter for the approval of the Access Arrangement. This is a question of whether there is a Shipper who might want capacity at that point and then whether for Epic Energy it is commercially viable to do so. North West Shelf Gas are well aware of the economic consequences faced by Epic Energy in transporting such a distance due to the operation of a particular contract inherited as part of the DBNGP acquisition. That aside Epic Energy believes a more economic and flexible approach is by the creation of a new lateral through the Mid West linking the two pipelines.

Provision of a service for delivery of gas from the DBNGP to the Goldfields Gas Pipeline is no different in principle from provision of a service to any other existing or new Delivery Point. As such, the Regulator does not consider it necessary for the Access Arrangement to specifically address such a service. Rather, the service could be obtained either under the terms, conditions and tariff of the Firm Service, or be obtained as a Non-Reference Service under terms and conditions determined by negotiation with Epic Energy.