Public Submission

By BHP Billiton

In Response to the Proposed Revisions to the

Dampier to Bunbury Natural Gas Pipeline

Access Arrangement

9 July 2010

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PART A - INTRODUCTION

1 Background

On 1 April 2010, DBNGP (WA) Transmission Pty Limited (**DBP**) submitted proposed revisions to the access arrangement (**Proposed Access Arrangement**) for the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) to the Economic Regulation Authority (**Regulator**) for approval under the *National Gas Access (Western Australia) Act 2009* which amends and implements the *National Gas Law* (**NGL**) and *National Gas Rules* (**NGR**) in Western Australia. DBP also provided supporting information to the Proposed Access Arrangement (**DBP's Supporting Information**).

On 15 April 2010, the Regulator invited submissions from interested parties on the Proposed Access Arrangement, to be submitted by 11 June 2010.[1] On 3 June 2010, the Regulator extended the period for submissions to 9 July 2010.[2]

2 Introduction

This submission is made by BHP Billiton (**BHPB**) in relation to the Proposed Access Arrangement and related material including:

(a) the Revised Access Arrangement Information lodged with the Proposed Access Arrangement (**RAAI**);

(b) DBP's Supporting Information; and

(c) the Issues Paper on the Proposed Revisions to the Access Arrangement prepared by the Regulator dated 7 May 2010 (**Issues Paper**).

3 Structure

This Submission is structured to focus on the following four areas:

(a) Part A - Introduction

(b) Part B - Rate of Return

(c) Part C - Reference Service

(d) Part D - Terms and Conditions

(e) Part E - Other Issues

Unless otherwise defined, words and expressions used in this Submission have the meaning given in the NGL and NGR.

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[1] ERA, April 2010, "Notice - Invitation for Public Submissions - Proposed Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline"

[2] ERA, June 2010, "Notice - Proposed Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline - Extension of Time to Make Submissions"

4 About BHPB

BHPB is the world's largest diversified natural resources company with significant positions in major commodity businesses, including aluminium, energy coal and metallurgical coal, copper, manganese, iron ore, uranium, nickel, silver and titanium minerals, and substantial interests in oil, gas, liquefied natural gas and diamonds.

BHPB is a major user of gas and thus has a significant demand for gas transportation. It is a key shipper on the DBNGP and like the other major shippers, on 1 January 2016, the tariffs payable on its long term gas transportation contracts are scheduled to revert to the reference tariffs payable under the access arrangement in force at that time.

5 Executive Summary

5.1 Rate of Return

BHPB submits that the 13.55% (nominal pre-tax) rate of return proposed by DBP in the Proposed Access Arrangement is not reasonable on the following basis:

(a) DBP has overstated the current risks facing the DBNGP and its owners.

(b) DBP's proposed cost of equity is inflated and unjustifiable:

  (i) under the NGR, DBP is required to use a financial model to estimate the cost of equity. It is not open to DBP to disregard financial models and instead use estimated forecasts of dividend yields;

  (ii) in addition, the use of estimated forecasts of dividend yields to determine the cost of equity is unreliable and inappropriate;

  (iii) the appropriate financial model to use under the NGR is the well accepted Capital Asset Pricing Model and the results from the alternative financial models should be disregarded; and

  (iv) the market risk premium proposed by DBP in its CAPM is overstated and should be 5-6%.

(c) DBP's proposed cost of debt is unreasonable:

  (i) DBP should have determined the cost of debt using the well accepted basis of the nominal risk free rate plus a cost of debt margin instead of using an alternative approach; and

  (ii) DBP's proposed cost of debt of 9.73% is too high in comparison to recent regulatory decisions and should be no greater than 8.75%.

(d) DBP should not have assigned a nil value to gamma:

  (i) recent regulatory decisions have not accepted 0 as an appropriate gamma;

  (ii) a value of 0 is not appropriate given the existence of Australian shareholding in the DBNGP; and

  (iii) an appropriate value for gamma is 50-65%.

5.2 Reference Service

DBP is proposing to offer only one reference service, the “R1 Service”. BHPB submits that the “R1 Service” is unlikely to be sought or utilised by a significant part of the market as it is less reliable than the “T1 Service”. Furthermore, BHPB submits that part haul, back haul, spot capacity and inlet sales services are likely to be sought by a significant part of the market and so should be included as reference services.

5.3 Terms and Conditions

BHPB submits that the information DBP has provided in relation to its proposed changes to the Terms and Conditions is wholly inadequate. It is BHPB’s view that any changes that do not have sufficient supporting information should not be approved by the Regulator, at least until such time as DBP provides this information and stakeholders have had an opportunity to consider it and make submissions.

In addition to its submission regarding the lack of information, BHPB also objects to several of DBP’s proposed amendments to the Terms and Conditions, on the basis that they are inappropriate or inconsistent with the legislative requirements.

5.4 Other issues

BHPB submits that the Regulator should examine DBP’s capital and operating expenditure figures closely to ensure that they comply with NGR requirements.

BHPB also submits that the proposed Reference Tariff Variation Mechanism is inappropriate on the grounds that it is too broad and is inconsistent with the national gas objective.

PART B - Rate of Return

6 Introduction

6.1 Issue

In determining the Reference Tariff, DBP have proposed a rate of return of 13.55% (nominal pre-tax). This is a 35.77% increase from the rate of return used in the current DBNGP Access Arrangement, being 9.98%.

6.2 Summary - BHPB Position

BHPB submits that the rate of return proposed by DBP in the Proposed Access Arrangement is not reasonable on the following basis:

(a) DBP has overstated the current risks facing the DBNGP and its owners.

(b) DBP's proposed cost of equity is inflated and unjustifiable:

  (i) under the NGR, DBP is required to use a financial model to estimate the cost of equity. It is not open to DBP to disregard financial models and instead use estimated forecasts of dividend yields;

  (ii) in addition, the use of estimated forecasts of dividend yields to determine the cost of equity is unreliable and inappropriate;

  (iii) the appropriate financial model to use under the NGR is the well accepted Capital Asset Pricing Model and the results from the alternative financial models should be disregarded; and

  (iv) the market risk premium proposed by DBP in its CAPM is overstated and should be 5-6%.

(c) DBP's proposed cost of debt is unreasonable:

  (i) DBP should have determined the cost of debt using the well accepted basis of the nominal risk free rate plus a cost of debt margin instead of using an alternative approach; and

  (ii) DBP's proposed cost of debt of 9.73% is too high in comparison to recent regulatory decisions and should be no greater than 8.75%.

(d) DBP should not have assigned a nil value to gamma:

  (i) recent regulatory decisions have not accepted 0 as an appropriate gamma;

  (ii) a value of 0 is not appropriate given the existence of Australian shareholding in the DBNGP; and

  (iii) an appropriate value for gamma is 50-65%.

6.3 NGL and NGR requirements

Section 24 of the NGL sets out six revenue and pricing principles which the Regulator is required to take into account when exercising discretion in approving those parts of an access arrangement relating to a reference tariff (s28(2) NGL). The principles are as follows:

"(2) A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in -

(a) providing reference services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes:

(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and

(b) the efficient provision of pipeline services; and

(c) the efficient use of the pipeline.

(4) Regard should be had to the capital base with respect to a pipeline adopted—

(a) in any previous full access arrangement decision or decision of a relevant Regulator under section 2 of the Gas Code;

(b) in the Rules.

(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services."

Rule 87 of the NGR states:

"(1) The rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.

(2) In determining a rate of return on capital:

(a) it will be assumed that the service provider:

(i) meets benchmark levels of efficiency; and

(ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice; and

(b) a well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be used; and a well accepted financial model, such as the Capital Asset Pricing Model, is to be used."

7 Risk Profile of the DBNGP

7.1 Issue

DBP suggests in its Supporting Information that the DBNGP is exposed to significant risks.

Although DBP only makes passing reference to its risk profile, the underlying risks associated with the operations of the DBNGP, and importantly the relativity of these risks to market norms, is a key driver of the required rate of return. Crucial to the assessment of an appropriate rate of return is the proposition that higher required returns can only be justified on the basis of higher risks.

7.2 Summary - BHPB position

BHPB submits that DBP have overstated the risks faced by the DBNGP, in particular:

(a) substitution risk;

(b) market risk; and

(c) the potential impact of CPRS on gas demand.

In addition, DBP admit to having very low levels of operating risk.[3]

The consequence of this low risk profile should necessarily be a lower required rate of return.

7.3 DBP has overstated the exposure of the DBNGP to substitution risk

DBP asserts that the DBNGP is exposed to significant risk from the possibility of substitution. BHPB strongly disputes this proposition. As demonstrated below, the evidence clearly shows that gas demand in Western Australia is expected to continue to grow. Furthermore, this demand for gas has been acknowledged by DBP themselves.[4]

In its submissions to the Regulator, DBP states that *"the rise in the price of gas threatens its continued use ... in electricity generation"*.[5] However, energy projections recently released by ABARE in March 2010 tell a different story. According to ABARE, much of Western Australia's projected 59% increase in gross electricity output from 2007-08 to 2029-30 will be driven by gas-fired electricity generation, which is projected to grow at an average rate of 2% a year. Gas-fired electricity generation is expected to account for 68% of the projected expansion in the state's electricity generation.[6] This is consistent with the trend over the last decade, with gas use having grown rapidly both in combined cycle plants and in cogeneration plants.[7] As at 2006, plants that can use natural gas made up approximately 70% of the electricity generating capacity in the State, compared to 23% of capacity in coal fired plants.[8]

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[3] DBP, April 2009, "DBNGP 25 years of Operation" http://www.energy.wa.gov.au/cproot/1534/2/Dampier%20to%20Bunbury%20Natural%20Gas%20Pipeline%20Reliability.pdf

[4] DBP, January 2010, "Completion of Third Pipeline Expansion Project to Meet the Energy Needs of Western Australia" http://www.dbp.net.au/press.html: Stage 5B Expansion Project was "carried out in direct response to the increased demand for gas for power generation and industrial processes associated with ongoing economic growth in WA."

[5] DBP, April 2010, "Submission 8: Rate of Return Public Version", page 36

[6] ABARE, March 2010, "Australian energy projections to 2029-30", page 32

[7] Economics Consulting Services, October 2008, "Report for the Domgas Alliance: Natural Gas Demand Outlook for Western Australia and Economic Impact", page 3

[8] Economics Consulting Services, October 2008, "Report for the Domgas Alliance: Natural Gas Demand Outlook for Western Australia and Economic Impact", page 3

These trends can also be seen nationally, with a clear substitution away from coal-fired generation to gas-fired generation.[9] Importantly, these trends away from coal to gas even take into account likely increases to domestic gas prices over the next two decades.[10]

DBP's assertion that the rise in price of gas threatens its continued use is refuted by ABARE's statements that *"the share of natural gas in Australian energy consumption has increased in the past 30 years and this trend is likely to continue in the longer term."*[11] According to ABARE, the share of coal in total primary energy consumption is projected to fall from 37% in 2007-08 to 23% in 2029-30. In contrast, gas is projected to be the fastest growing fossil fuel over that period, with its share projected to increase from 22% to 33%. The growth in demand for gas is driven primarily by the electricity generation and mining sectors.[12]

This forecast of growing demand is supported by the Chamber of Minerals & Energy Western Australia (**CME**), who state that the expected demand for gas from the minerals and energy sector is forecast to grow at a compound annual growth rate of 6.7% for the period 2008-2014 to 286 PJ/a, an additional 95PJ/a over 2007 consumption.[13]

These independent forecasts are reinforced by DBP's own statements in January 2010 in relation to their completion of the Stage 5B Expansion Project, that *"extra gas transmission capacity ... [was] crucial in ensuring continued economic growth in WA."* Further, the expansion was *"carried out in direct response to the* ***increased demand for gas for power generation and industrial processes*** *associated with ongoing economic growth in WA"*.[14]

Overall, CME forecasts that state-wide gas demand for all industries will increase at a compound annual growth rate of 5.3% for the period 2008-2014, being driven primarily by demand from the minerals and energy sector. This is shown in the graph below.[15]

9 ABARE, March 2010, "Australian energy projections to 2029-30", page 32: the share of coal in electricity generation is expected to fall from 73% to 43% by 2029-30. The share of gas is expected to grow from 19% to 37% over the same period.

10 ABARE, March 2010, "Australian energy projections to 2029-30", page 34

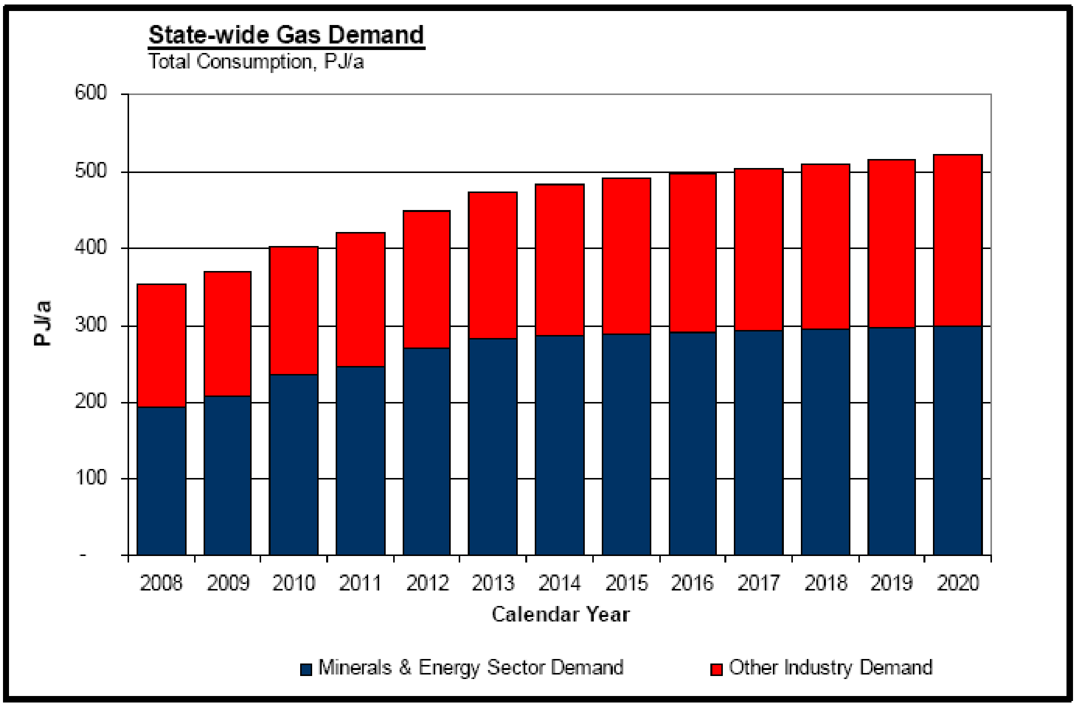
11 ABARE, April 2010, "Energy in Australia 2010", page 13

12 ABARE, March 2010, "Australian energy projections to 2029-30", page 27

13 The Chamber of Minerals & Energy Western Australia, December 2008, "Developing a Growth Outlook for WA's Minerals & Energy Industry: Outlook and Implications", page 61

14 DBP, January 2010, "Completion of Third Pipeline Expansion Project to Meet the Energy Needs of Western Australia" http://www.dbp.net.au/press.html

15 Extracted from The Chamber of Minerals & Energy Western Australia, December 2008, "Developing a Growth Outlook for WA's Minerals & Energy Industry: Outlook and Implications", page 62. Source: Baseline (2007) minerals and energy sector and Other Industry gas consumption provided by DOIR. Other Industry gas demand growth rates based on Department of Water - Water Availability Report, 2008 industry growth rates. Minerals and Energy sector gas demand sourced from direct survey data with extrapolated growth.



From the above evidence, it is clear that DBP have overstated the exposure of the DBNGP to substitution risk.

7.4 DBP has minimal exposure to market risk

In discussing the exposure of the DBNGP to market risk, DBP makes passing reference to risks associated with the effects of the Global Financial Crisis (**GFC**), its relatively small numbers of shippers, the creditworthiness of a number of shippers and the Varanus Island incident.

BHPB submits that these issues represent minimal, if any, risk to DBP, particularly when compared to other industries and should not be used to justify higher returns.

(a) *Impact of the GFC and Varanus incident*

There is clear evidence that the DBNGP has continued to perform well despite the GFC. Babcock and Brown Infrastructure's (now Prime Infrastructure, 20% owner of DBNGP) own opinion is that during this relevant period, the DBNGP had "solid operational performance".[16]

Relevant indicators include, for FY09:[17]

- transmission revenue increased 19.7% to $347m;
- total revenue increased 15.1% to $350m;
- EBITDA increased 18.1% to $274m;
- throughput decreased a marginal 1.7% to 290 PJs; and
- total capacity increased 9.5% to 1026 TJ/day.

16 Babcock and Brown Infrastructure, "Annual Report 2009", page 14

17 DUET Group, "Annual Report 2009", page 13

This solid performance also continued in the 6 months to December 09, relevant indicators including:[18]

- transmission revenue increased 12% on the 6 months to December 08 to $186m;
- total revenue increased 15.4% on the 6 months to December 08 to $195m;
- EBITDA increased 12% on the 6 months to December 08 to $149m;
- throughput for the 12 months to 31 December 2009 was 341 PJs; and
- capacity for the 1 month to 31 December 09 was 1018 TJ/day.

These strong results were achieved despite the fact that in mid-to-late 2008 there were two major events, namely the Varanus Island explosion and the Global Financial Crisis. Individually, each of these is extremely rare, and together they are a less than one in 50 years event.

The fact that despite this extremely unlikely combination of events, the DBNGP continued to perform solidly, establishes that its exposure to risk is relatively low. As one of the owners of the DBNGP themselves said, the *"Varanus Island incident had minimal impact on DBP's EBITDA due to the mainly capacity reservation-driven revenue"*.[19]

The figures and comments published by another DBNGP owner, DUET, also paints a picture of healthy operation and continued growth. On their website, DUET state that the key investment attributes of the DBNGP are its predictable revenue, competitive position and development and growth potential. According to DUET, the DBNGP has *"stable and predictable revenues"*. Furthermore, *"natural gas supplies approximately 50% of total primary energy consumption in Western Australia,"* with *"natural gas consumption in Western Australia ... [having] increased by 4% per annum over the past 10 years."*[20]

This bright picture of expectations in relation to the DBNGP, and its ability to continue to grow and perform well in globally difficult times when many other companies are struggling, clearly demonstrates that the DBNGP has a low exposure to market risk.

(b) *High proportion of fixed charges*

BHPB submits that long-term fixed charge contracts significantly reduce a pipeline's sensitivity to demand changes. Given the high level of fixed charge commitments on the DBNGP,[21] there is a strong case to reduce the cost of equity relative to the market to reflect DBP's reduced volume and price sensitivity.

(c) *Relatively small numbers of shippers and creditworthiness*

DBP asserts that their relatively small numbers of shippers makes Western Australian gas transmission pipelines more exposed to market risk than pipelines serving the Eastern Australian market. DBP submits that this was highlighted by the GFC during which the creditworthiness of a number of shippers came into question.

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[18] DUET Group, "Management Information Report for the half year ended 31 December 2009", page 19-25

[19] Babcock and Brown Infrastructure, "Annual Report 2009", page 14

[20] www.duet.net.au/duet/asset-portfolio/dbngp.htm

[21] DUET Group, "Annual Report 2009" page 12: "DBP has entered into standard long-term contracts with the major shippers using the pipeline - other than Alcoa. Under these contracts, approximately 80% of the tariff is paid on a capacity reservation basis (take-or-pay), with the remaining 20% depending on the shipper's actual throughput."

BHPB disputes these assertions. DBP's owners consider that the exposure of the DBNGP to market risk is low given that it has *"long-term contracts in place until at least 2019 with all of the shippers on the pipeline, ensuring stable and predictable revenues"*[22] and, as outlined above, a high level of DBP's revenue is on a take-or-pay basis. Furthermore, DBP, by its owner's admission, only invests in expansion projects on the basis of firm, long-term contractual commitments by shippers.[23]

BHPB submits that it is not appropriate for the Regulator to consider the impact of the creditworthiness of shippers as there is no reasonable likelihood of any insolvency of shippers effecting underlying gas demand.

In particular, BHPB notes that the majority of the DBNGP capacity is contracted to large stable groups with strong balance sheets and/or good credit ratings and, in the case of one, Government ownership, namely:

- BHPB;
- Alcoa;
- ERM Power and Sumitomo Corporation;
- Wesfarmers; and
- Verve Energy.

These shippers constitute a significant percentage of the pipeline capacity and revenue. In addition, the majority of demand of the other key shipper and gas market intermediary, Alinta, is used to supply strong underlying gas demand. An example of this enduring underlying demand is the residential gas consumption demand which accounts for over a quarter of Alinta's overall demand. Not only is this underlying residential demand enduring, but nationally, has grown 60% over the past 20 years and is forecast to grow a further 21% over the next 10 years.[24] This strong underlying demand means that any potential issues with Alinta are unlikely to affect demand for use of the DBNGP.

Alternatively, if the Regulator is of the view that the creditworthiness of shippers is an appropriate consideration, BHPB submits that the provisions of the Terms and Conditions of the Proposed Access Arrangement (and existing contracts) provide DBP with sufficient rights to protect itself against the potential default of its customers as a result of insolvency. Clause 30.5 of the Terms and Conditions provides:

> *"If the Operator is (acting reasonably) not sufficiently certain that the Shipper is in a position to meet or continue to meet its obligations under this Contract, the Operator may require, and the Shipper must provide, security for those obligations to the Operator's reasonable satisfaction."*

BHPB submits that the right for DBP to require security under clause 30.5 is an appropriate mechanism and consistent with how such a risk is managed in a competitive environment and is therefore more consistent with the objectives and principles underpinning the NGR.

[22] DUET Group, "Annual Report 2009", page 12

[23] DUET Group, "Annual Report 2009", page 12

[24] Department of the Environment, Water, Heritage and the Arts, 2008, "Energy use in the Australian residential sector 1986-2020", page 23: Figures for total mains gas consumption in petajoules for Australia: 89.2 (1990), 143.1 (2010), 173.6 (2020).

7.5 The impact of the CPRS

BHPB submits that the CPRS will make gas more competitive with coal thus leading to increased demand. As stated by ABARE, *"[g]as consumption is projected to rise by 3.4 per cent a year …This growth in demand…reflects the shift to less carbon-intensive fuels in a carbon constrained environment. Much of this growth is at the expense of coal."*[25]

7.6 DBP have low levels of operating risk

In April 2009, in a presentation published on the Office of Energy Website,[26] DBP outlined the reliability of the DBNGP and its ability to deliver security of supply. In support of its reliability, DBP cited its adoption of good industry standards and practices in design, its conservative tranche methodology for capacity services, its incorporation of good systems and processes and its awareness and proactive approach to changing environments. These factors, by DBP's own admission, point to a very low operating risk for the DBNGP.

8 Cost of equity

8.1 Issue

DBP have proposed a cost of equity of 13.5%.

In doing so, DBP have effectively ignored the results of the Capital Asset Pricing Model (CAPM) and other financial models, preferring instead to adopt an approach based on analysing dividend yield forecasts.

8.2 Summary - BHPB Position

It is BHPB's view that the cost of equity of 13.5% proposed by DBP is inflated and unjustifiable. BHPB's submissions in respect of the cost of equity are as follows:

(a) under the NGR, DBP is required to use a financial model to estimate the cost of equity. It is not open to DBP to disregard financial models and instead use estimated forecasts of dividend yields;

(b) in addition, the use of estimated forecasts of dividend yields to determine the cost of equity is unreliable and inappropriate;

(c) the appropriate financial model to use under the NGR is the well accepted Capital Asset Pricing Model and the results from the alternative financial models should be disregarded; and

(d) the market risk premium proposed by DBP in its CAPM is overstated and should be 5-6%.

8.3 DBP is required to use a financial model

BHPB submits that under the NGR, DBP is required to use a financial model to estimate the cost of equity. It is not open to DBP under the NGR to disregard the results of financial models in favour of an informal estimate based on dividend yields.

Rule 87 of the NGR states that in determining a rate of return, a *"well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be*

[25] ABARE, March 2010, "Australian energy projections to 2029-30", page 27

[26] DBP, April 2009, "DBNGP 25 years of Operation" http://www.energy.wa.gov.au/cproot/1534/2/Dampier% 20 to%20Bunbury%20Natural%20Gas%20Pipeline%20Reliability.pdf

used; and a ***well accepted financial model****, such as the Capital Asset Pricing Model,* ***is to be used****."*

Although DBP have referred to financial models in their access arrangement information, they have then effectively ignored the results of these models and instead based their estimate of cost of equity purely on an estimated forecast of dividend yields plus a premium. BHPB submits that it is not open to DBP to do this when the legislation clearly states that a model is to be used.

Given its ordinary meaning, as is required by law,[27] the phrase "is to be used" is mandatory in nature. DBP has failed to provide any basis for adopting an alternative interpretation of these words.

Clearly, DBP's method of simply referring to the models and having them "guide the process of establishing the rate of return"[28] is inconsistent with the legislation which requires **use** of the models.

Contrary to DBP's statements, there is no room in the legislation to "take into account the inherent ability or inability of a model to provide reliable information in respect of both elements of the criteria contained in Rule 87(1),"[29] or at least not when determining cost of equity. The use of a model for calculating cost of equity is mandated. The criteria in Rule 87(1) cannot be satisfied by simply disregarding 87(2), as DBP have done. This submission is supported by the AER's statement that it does not accept that Rule 87(1) and not Rule 87(2) sets the primary requirements of Rule 87. According to the AER, in order to comply with Rule 87, both Rule 87(1) and Rule 87(2) must be met. There is no hierarchy of importance.[30]

It is therefore not open to DBP under the NGR to disregard formal asset pricing models and instead rely on an informal, unsubstantiated estimate.

8.4 The use of estimated forecasts of dividend yields is unreliable and inappropriate

BHPB submits that aside from the fact that using estimated forecast dividend yields to estimate the cost of equity fails to satisfy the legislative requirements to use a financial model, it also should be further disregarded for the following reasons:

(i) the estimate is overly simplistic and the use of such estimated forecasts has been demonstrated to provide unreliable results;

(ii) a reliance on analysts' estimated forecasts has been shown to likely result in an upwardly biased estimate; and

(iii) contrary to Rule 42 of the NGR, DBP have provided insufficient evidence to support the input assumptions on which its estimate is based.

The concerns raised by BHPB are summarised by Brealey, Myers and Allan in their leading corporate finance textbook:[31]

> *"Estimates of this kind are only as good as the long-term forecasts on which they are based. For example, several studies have observed that security analysts are subject to behavioural biases and their forecasts tend to be overly optimistic. If so, such DCF estimates of the cost of equity should be regarded as upper estimates of the true figure".*

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[27] *Cozens v Brutus* [1973] AC 854; *Amalgamated Society of Engineers v Adelaide Steamship Co Ltd (the Engineer's Case)* (1920) 28 CLR 129 at 161-2

[28] DBP, April 2010, "Submission 8: Rate of Return Public Version", page 28

[29] DBP, April 2010, "Submission 8: Rate of Return Public Version", page 10

[30] AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 114

[31] Brealey, R. A.; Myers, S. C.; Allen, F. *Corporate Finance*, McGraw-Hill Irwin, 8th Edition, 2006, page 67

Each of these concerns is discussed in more detail below. Based on these concerns, BHPB submits that DBP's estimated cost of equity of 13.5% should be disregarded.

(a) *DBP's use of estimated forecast dividend yields is overly simplistic and the use of such estimated forecasts has been demonstrated to provide unreliable results*

The use of estimated forecast dividend yields by DBP is overly simplistic, and represents a significant departure from the more rigorous approach adopted by regulators. In particular, estimates for the cost of equity based on such dividend yields are highly sensitive to input assumptions, many of which have significant uncertainty in their own right (for example forecast dividend yields and growth rates).

These concerns are supported by recent academic research, which demonstrate that expected return estimates from earnings and dividend based methods are highly unreliable. The results are summarised by Easton and Sommets:[32]

> *"The conclusion from the very recent studies that examine the validity of firm-specific estimates of the implied expected rates of return derived from reverse-engineering earnings-based valuation models is that these estimates are poor, indeed."*

BHPB submits that the uncertainty from such estimates is likely to be greater than that from well accepted financial models such as the CAPM. As such, the DBP cost of equity estimate of 13.5% should be disregarded.

(b) *Estimates for the cost of equity based on estimated forecasts of dividend yields are likely to result in an upwardly biased estimate for the cost of equity capital*

Aside from being unreliable, the DBP cost of equity estimate of 13.5% is likely to be upwardly biased and thus overstate the true cost of equity capital. This bias arises from a reliance on analyst earnings, growth and share price appreciation forecasts, which are known to be biased and overly optimistic.[33]

Recent academic research has estimated that expected rates of return based on analyst estimates have an upward bias in the region of 2.5 – 3.0%. The results are summarised by Easton and Sommets:[34]

> *"Since analysts' forecasts are pervasively (though not uniformly) optimistic, estimates of the implied expected rate of return using forecasts are pervasively and significantly upwardly biased"*

BHPB submits that there is significant bias likely to be present in the DBP cost of equity estimate or, at the very least, considerable risk of such a bias. On this basis, the use of estimated forecast dividend yields should not be accepted as it is likely to produce outcomes which are inconsistent with the NGL, NGR and the national gas objective.

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[32] Easton, P. D.; Sommers, G. A.; "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts", *Journal of Accounting Research*, 2007 (45), 983

[33] See, for example: (a) Richardson, S.; Teoh, S. H.; Wysocki, P. D., "The Walk-down to Beatable Analyst Forecasts: The Role of Equity Issuances and Insider Trading Incentives", *Contemporary Accounting Research*, 2004 (21), 885; (b) Dugar, A.; Nathan, S., "The Effect of Investment Banking Relationships on Financial Analysts' Earnings Investment Recommendations", *Contemporary Accounting Research*, 1995 (12), 131

[34] Easton, P. D.; Sommers, G. A.; "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts", *Journal of Accounting Research*, 2007 (45), 983

(c) *DBP's public submission provides insufficient background and support for the data used to arrive at its cost of equity estimate of 13.5%*

DBP submits that its cost of equity estimate of 13.5% is based on "empirical evidence" that is intended to reflect "current market conditions". However, contrary to the requirements of Rule 42 of the NGR, DBP provide no transparency in respect of this data, including its support, or reference to the source. This means that the data cannot be verified or properly assessed, and is thus inappropriate as a basis for a regulated decision.

The DBP's estimate of the cost of equity is based on their observation that *"[t]he average of equity analysts' dividend yield forecasts for comparable Australian infrastructure businesses over the period 2010 to 2012 was 10.5%"*.[35] No further information into the source of this assertion is provided in the public submission, and supporting empirical evidence has been deleted from DBP's supporting Submission 8.[36] Without this evidence, it is not possible to make detailed submissions in response.

The DBP cost of equity estimate also assumes a growth in dividend yields above expected inflation: *"[w]ith the likely improvement in market conditions following the global financial crisis, an expectation of further – real - growth in the yields from infrastructure businesses, of at least 1.00%, is reasonable"*.[37] Again, no evidence for this assertion is provided in the public submission, and its theoretical basis is questionable.

BHPB submit that the DBP's estimated cost of equity of 13.5% should be viewed as an unsupported and unsubstantiated assertion that cannot be verified or tested. As such, BHPB submit that that this estimate should be disregarded.

8.5 CAPM is the most appropriate model to use and the other models should be disregarded

Given that DBP is required by the NGR to use a financial model, BHPB submits that the CAPM is the most appropriate model to use and the results from the other models referenced by DBP in its submission should be disregarded. This is because the CAPM has consistently been the principal model used by Australian regulators and furthermore, the alternative models referred to by DBP are inappropriate for application in a regulatory context.

(a) *CAPM is the principal model used by Australian regulators*

Rule 87 of the NGR requires a "*well accepted financial model, such as the Capital Asset Pricing Model"* to be used. On this basis it is clearly open for the Regulator to approve an Access Arrangement with pricing determined using the CAPM.

A review of readily available Australian regulatory decisions reveals that the CAPM is the principal model used by Australian regulators in determining the appropriate cost of equity. This is demonstrated by the table below, which sets out a list of previous decisions, and the cost of equity model used in them.

Importantly, in its decision on the NSW Gas Network last month, the AER expressly refused to accept the use of the Fama-French Model and instead required the use of the CAPM. The AER stated that *"[t]he use of the CAPM to determine the cost of equity complies with the applicable requirements of the NGL and the NGR and is consistent with the applicable criteria prescribed by the NGL and the NGR…the use of the CAPM (instead of the FFM) for determining the rate of return is consistent with the revenue and pricing*

[35] DBP, April 2010, "Revised Access Arrangement Information Public Version", page 23

[36] DBP , April 2010, "Submission 8: Rate of Return Public Version", page 34

[37] DBP, April 2010, "Revised Access Arrangement Information Public Version", page 23

principles set out in section 24 of the NGL and will or is likely to contribute to the achievement of the National Gas Objective (NGO) in section 23 of the NGL.'[38] The AER also state that regulators are a relevant group for consideration of whether a model is a well accepted model.[39]

Year	Decision	Cost of equity model
2010	ERA - Goldfields Gas Pipeline (Final Decision)	CAPM
2010	AER - NSW Gas Networks (Final Decision)	CAPM
2010	AER - Wagga Wagga Natural Gas Distribution Network (Final Decision)	CAPM
2010	AER - ACT, Queanbeyan and Palerang Gas Distribution Network (Final Decision)	CAPM
2008	ACCC - Principal Transmission System (GasNet System) (Final Approval)	CAPM
2008	ESC - Gas Access Arrangements (Envestra (Victoria), Multinet, SP AustNet, Envestra (Albury)) (Further Final Decision and Approval)	CAPM
2007	ACCC - Dawson Valley Pipeline (Final Decision)	CAPM
2006	ACCC - Roma to Brisbane Pipeline (Final Decision)	CAPM
2006	QCA - Allgas Energy System (Final Decision)	CAPM
2006	QCA - Envestra Limited Gas Distribution Pipeline (Final Decision)	CAPM
2006	ESC - South Australian Gas Distribution System (Final Decision)	CAPM
2005	ERA - Dampier to Bunbury Natural Gas Pipeline (Draft Decision approved in Final Decision)	CAPM
2005	ERA - Goldfields Gas Pipeline (Final Decision)	CAPM
2005	IPART - AGL Gas Networks (Final Decision)	CAPM
2005	IPART - Country Energy Gas Network (Final Decision)	CAPM
2005	ERA - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	CAPM
2004	ICRC - ActewAGL Natural Gas System (Final Decision)	CAPM
2003	ACCC - Moomba to Sydney Pipeline (Final Approval)	CAPM
2003	Australian Competition Tribunal - GasNet System (Tribunal Decision)	CAPM

[38] AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 172
[39] AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 118

Year	Decision	Cost of equity model
2002	ACCC - Amadeus Basin to Darwin Pipeline (Final Decision)	CAPM
2001	ACCC - Moomba to Adelaide Pipeline System (Final Decision)	CAPM
2001	QCA - Envestra Limited Gas Distribution (Final Decision Errata)	CAPM
2001	QCA - Allgas Energy System (Final Decision Errata)	CAPM
2000	ACCC - Central West Pipeline (Final Decision)	CAPM
2000	ICRC - ActewAGL Natural Gas System (Final Decision)	CAPM
2000	Offgar - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	CAPM

The fact that the use of the CAPM is mandatory under the National Electricity Rules, and is the only model expressly referred to under the NGR, is further proof of the suitability of using the CAPM to determine cost of equity, contrary to DBP's assertions. The evidence shows that in practice, the CAPM is the model most commonly used for cost of equity, and crucially has been endorsed in a number of pieces of legislation as appropriate.

Given the historical reliance on the CAPM, and the NGR's requirement that a *"well accepted financial model"* be used, there is no reason for DBP or the Regulator to depart from the use of the CAPM in calculating a cost of equity for the DBNGP. In fact, BHPB submits that to move away from the CAPM would risk introducing an element of regulatory uncertainty. This point has also been emphasised by regulators.[40]

The words "well accepted" must be read in the context of the NGR. BHPB submits that the words cannot mean well accepted in abstract theory, or well accepted in financial literature. In context, the words must mean well accepted in a practical context including for determining pricing for regulated assets.

The evidence clearly demonstrates that it is the CAPM, and no other, that is the appropriate model to use in this context. DBP has not identified any special circumstances for the DBNGP that would warrant the departure from the general practice of using the CAPM.

(b) *The alternative models referred to by DBP are inappropriate for application in a regulatory context*

BHPB submits that the results from the other financial models considered by DBP, being Black's CAPM, the Fama-French three factor model and the Zero beta Fama-French three factor model should be disregarded. In particular, BHPB submits that: (i) the alternative models are not "well accepted" as required by the NGR; and (ii) the significant uncertainty about the academic relevance, proper application, and results derived from these models means that they are inappropriate for application in a regulatory context.

[40] ESC, March 2008, "Gas Access Arrangement Review 2008-2012 Final Decision - Public Version", page 473-474

BHPB submits that, based on these concerns, the results from the CAPM remain the most trustworthy and robust for use in a regulatory context.

(i) The alternative models are not "well accepted"

The CAPM remains the most widely used and trusted asset pricing model. The state-of-play is summarised by leading corporate finance practitioners Koller, Goedhart and Wessels in their widely used textbook "Valuation":[41]

> *"The bottom line? It takes a better theory to kill an existing theory, and we have yet to see a better theory. Therefore, we continue to use the CAPM while keeping a watchful eye on new research in the area"*

As discussed above, this pragmatic position is also supported by the vast majority of regulatory bodies, which continue to adopt the CAPM as their standard model for cost of equity estimates.

Furthermore, in a very recent regulatory decision, the AER expressly concluded that on the information before it, the Fama-French model is not well accepted by academics or financial market practitioners.[42] The AER considered that the Fama French model does not produce a better estimate or forecast than the CAPM of cost of equity.[43] After careful analysis, the AER concluded that the Fama-French model is not supported as reliable or accurate and the estimates generated by it are not arrived at on a reasonable basis.[44]

BHPB submits that the CAPM continues to remain the most appropriate financial model for estimating the cost of equity capital and that the alternative models are not "well accepted", and in fact DBP does not point to a specific example of where any alternative model has been used in a relevant context.

(ii) The significant uncertainty about the academic relevance, proper application, and results from alternative asset pricing models make them inappropriate for application in a regulatory context

The DBP submissions refer to the Fama-French three factor model (and related zero-beta version) in estimating the cost of equity capital. This model incorporates additional risk factors (in addition to market risk), and implies that expected returns are related to a company's exposure to a book-market factor ("high minus low", HML) and a size factor ("small minus big", SMB).

The additional factors in the Fama-French models are empirical factors based on analysis of historical data, for which the theoretical foundations have been questioned. As stated by Ross, Westerfield, Jaffe and Jordan in their leading textbook "Modern Financial Management":[45]

> *"There are a variety of possible explanations for these results, and the issues have certainly not been settled. Critics of the empirical approach are sceptical of what they call data mining."*

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41 Koller, T.; Goedhart, M.; Wessels, D. *Valuation: Measuring and Managing the Value of Companies*, John Wiley & Sons, 4th Edition, 2005, page 324.

42 AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 126, 134

43 AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 148

44 AER, June 2010, "Final decision - Public: Access arrangement proposal for the NSW gas networks", page 171

45 Ross, S. A.; Westerfield, R. W.; Jaffe, J.; Jordan, B. D.; *Modern Financial Management*, McGraw-Hill Irwin, 8th Edition (International), 2008, page 334.

In addition to their theoretical validity, recent academic research has questioned whether inclusion of these additional risk factors is appropriate on empirical grounds.[46] For example, research has suggested that excess returns for an asset's exposure to the book-market factor are overstated, and are most likely negligible.

These observations are important in the present context because the majority of the difference between the costs of equity capital proposed by DBP on the basis of the Fama-French model (11.98%) and the CAPM (8.79%) arise from exposure to the book-market factor that is included in the former but not the latter.[47] Excluding this additional factor from the Fama-French model would likely generate a cost of equity estimate that was much more closely aligned with that from the CAPM.

BHPB submit that the cost of equity derived from the Fama-French models should be disregarded based on continued uncertainty about the theoretical foundations of this model and recent evidence against inclusion of the book-market factor. This uncertainty means that such a model is inappropriate for application in a regulatory model.

The DBP and NERA submissions also provide results for zero-beta versions of the CAPM (the "Black CAPM") and Fama-French three factor models ("zero beta Fama-French"). These models incorporate a return above the risk free rate for holding equities (the "zero-beta premium"), designed to relax the assumption of the CAPM that investors can borrow and lend at the risk-free rate.

NERA estimate a zero-beta premium of 6.5%, which is adopted by DBP.[48] This zero-beta premium is significantly above that expected based on theory and simple market observations. As stated by NERA:

> *"An enthusiasm for this model, though, should be tempered by the fact that empirical estimates of the difference between the zero-beta and risk free rates are higher than perhaps theory might expect one to expect…..theory suggests that the difference should not exceed the difference between the rates at which investors can borrow and lend."*

BHPB submits that the discrepancy between the zero-beta premium in the models proposed by NERA and DBP and that expected based on theoretical grounds calls into question the validity of these models.

Furthermore, the Black CAPM proposed by NERA and adopted by DBP appears to be inconsistent with the basic principles of asset pricing theory. The model implies that investors achieve the same expected return for any stock, independent of the nature of that stock (size, industry, or any other characteristic). This arises because their only risk exposure is to the zero-beta premium, while market exposure is not rewarded (market risk premium is zero).

Similarly, the zero beta Fama-French model proposed by NERA and adopted by DBP implies that investors are not rewarded for bearing market risk beyond that

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[46] See, for example: (a) Ferguson, M. F.; Shockley, R. L., "Equilibrium Anomalies", *The Journal of Finance*, 2003 (58), 2549; (b) Brav, A.; Lehavy, R.; Michaely, R., "Using Expectations to Test Asset Pricing Models", *Financial Management*, 2005, 31; (c) Ang, A.; Chen, J., "CAPM over the long run: 1926 – 2001", *Journal of Empirical Finance* 2007 (14), 1

[47] DBP, April 2010, "Submission 8: Rate of Return Public Version", page 20

[48] NERA Economic Consulting, March 2010, "The Required Rate of Return on Equity for a Gas Transmission Pipeline"

captured by exposure to book-market and a size factors. Such an outcome again appears at odds with well accepted asset pricing theory.

For these reasons, BHPB submits that the cost of equity estimates from these zero beta models should be disregarded.

The areas of dispute and agreement amongst different asset pricing models is succinctly summarised by Brealey, Myers and Allan in their leading corporate finance textbook:[49]

> *"Each of these different models of risk and return has its fan club. However, all financial economists agree on two basic principles: (1) Investors require extra expected return for taking on risk, and (2) they appear to be concerned predominantly with the risk that they cannot eliminate by diversification."*

The CAPM is still the most widely used model by practitioners and regulatory bodies for estimating the cost of equity. It captures the main principles of modern asset pricing theory in a framework that is easily understood, robust, and academically defensible. As stated in a previous regulatory decision, to move away from the CAPM would risk introducing an element of regulatory uncertainty.[50] For all of these reasons, BHPB submits that only the results from the CAPM should be considered, and results from other asset pricing models should be disregarded.

8.6 Capital Asset Pricing Model parameters

BHPB submits that in using the CAPM, the Regulator must ensure that appropriate and justifiable variables are used. On this basis BHPB submits that the market risk premium proposed by DBP is overstated.

DBP have proposed a market risk premium (**MRP**) of 6.5%. BHPB submits that this proposed MRP is too high and inconsistent with the average MRP adopted by the market.

Approaches used to estimate the MRP can be divided into the following two distinct groups:

- firstly, using historical returns from equities and risk-free assets to determine a historical MRP; and

- secondly, using economic or financial models to determine investors' expectations for the future MRP.

The former gives reliable estimates of the MRP realised by investors in the past, but it is unclear how relevant these estimates are to the future. In contrast, forward looking models provide estimates that are more relevant to the future, but which are often variable and highly dependent on the assumptions chosen.

BHPB agrees with the Regulator that the market risk premium should be determined on the basis of both observed historical equity premia achieved in the market and a range of information sources on current and future expectations of equity premia.[51]

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49 Brealey, R. A.; Myers, S. C.; Allen, F. *Corporate Finance*, McGraw-Hill Irwin, 8th Edition, 2006, page 205

50 ESC, March 2008, "Gas Access Arrangement Review 2008-2012 Final Decision - Public Version", page 473-474

51 ERA, June 2009, "Final Determination on the 2009 Weighted Average Cost of Capital for TPI's Railway Network", page 20

(a) *Historical data*

Recently, the AER has noted that long term historical estimates (1883-2008, 1937-2008, and 1958-2008) produce a range of 5.7 to 6.2 percent.[52]

Historical data does not necessarily reflect future expectations. Dimson, Marsh and Staunton argued that structural changes in the economy and equity markets in the latter half of the twentieth century (which are already priced into equities) make it likely that future equity returns will be lower than those obtained historically.[53] This means that a forward looking MRP should be lower than that estimated from historical data.

This emphasises the limitations of relying on historical data alone, and the need to consider other approaches and models to estimate the MRP. The authors suggested that to estimate the forward looking MRP, past MRP needs to be adjusted downwards for unanticipated cash flow growth and unanticipated declines in business and investment risk. The authors recommended a downward adjustment of one to two percent.[54]

(b) *Future expectations*

Recent investment bank research (based upon availability of MRP information, as these assumptions are infrequently disclosed in contemporary equity research) is tabulated below:

Source	Publication / Date	MRP (%)
Merrill Lynch[55]	1 December 2008	5.0
Macquarie Research[56]	1 April 2009	5.5
GSJBW[57]	24 April 2009	6.0
RBS[58]	21 May 2009	6.0
Morgan Stanley[59]	9 June 2009	6.0
Austock Securities[60]	13 March 2009	6.0
Average		**5.75**

As evidenced by this information, the average expectations of market practitioners is 5.75% and does not support a MRP of 6.5%.

52 AER, May 2009, “Final Decision - Electricity transmission and distribution network service providers - Review of weighted average cost of capital (WACC) parameters”, page xiv

53 Dimson, Marsh and Staunton, working paper, September 2002 “Global evidence on the equity risk premium”, London Business School

54 Dimson, Marsh and Staunton, working paper, September 2002 “Global evidence on the equity risk premium”, London Business School

55 Merrill Lynch, broker report, 1 December 2008, “Boral Ltd. Is this rock bottom?”

56 Macquarie Research, broker report, 1 April 2009, “Fortescue Metals Group FIRB ticks the box”

57 GSJBW, results commentary, 24 April 2009, “Fortescue Metals Group Ltd 3Q09 Production And Earnings Results”

58 RBS, broker report, 21 May 2009, “Fortescue Metals Group A leveraged iron ore play”

59 Morgan Stanley, broker report, 9 June 2009, “Telstra Corporation Circling the Wagons: Incumbent Defense”

60 Securities, broker report, 13 March 2009, “Sunland Group Ltd (SDG) Dirt cheap, but negative near term catalysts likely”

(c) *Relevant regulatory decisions*

In addition to historical data and market expectations, there is also limited support for DBP's proposed MRP position in recent regulatory decisions, as set out in the table below.

Year	Decision	MRP (%)
2010	ERA - Goldfields Gas Pipeline (Final Decision)	5.0-7.0
2010	AER - NSW Gas Networks (Final Decision)	6.5
2010	AER - Wagga Wagga Natural Gas Distribution Network (Final Decision)	6.5
2010	AER - ACT, Queanbeyan and Palerang Gas Distribution Network (Final Decision)	6.5
2008	ACCC - Principal Transmission System (GasNet System) (Final Approval)	6.0
2008	ESC - Gas Access Arrangements (Envestra (Victoria), Multinet, SP AustNet, Envestra (Albury)) (Further Final Decision and Approval)	6.0
2007	ACCC - Dawson Valley Pipeline (Final Decision)	6.0
2006	ACCC - Roma to Brisbane Pipeline (Final Decision)	6.0
2006	QCA - Allgas Energy System (Final Decision)	6.0
2006	QCA - Envestra Limited Gas Distribution Pipeline (Final Decision)	6.0
2006	ESC - South Australian Gas Distribution System (Final Decision)	6.0
2005	ERA - Dampier to Bunbury Natural Gas Pipeline (Draft Decision approved in Final Decision)	5.0-6.0
2005	ERA - Goldfields Gas Pipeline (Final Decision)	5.0-6.0
2005	IPART - AGL Gas Networks (Final Decision)	5.5-6.5
2005	IPART - Country Energy Gas Network (Final Decision)	6.0
2005	ERA - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	5.0-6.0
2004	ICRC - ActewAGL Natural Gas System (Final Decision)	6.0
2003	ACCC - Moomba to Sydney Pipeline (Final Approval)	6.0
2003	Australian Competition Tribunal - GasNet System (Tribunal Decision)	6.0
2002	ACCC - Amadeus Basin to Darwin Pipeline (Final Decision)	6.0

Year	Decision	MRP (%)
2001	ACCC - Moomba to Adelaide Pipeline System (Final Decision)	6.0
2001	QCA - Envestra Limited Gas Distribution (Final Decision Errata)	6.0
2001	QCA - Allgas Energy System (Final Decision Errata)	6.0
2000	ACCC - Central West Pipeline (Final Decision)	6.0
2000	ICRC - ActewAGL Natural Gas System (Final Decision)	5.0-6.0
2000	Offgar - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	6.0

(d) *Appropriate market risk premium*

In light of the comments above BHPB supports an MRP of 5-6%.

9 Cost of debt

9.1 Issue

DBP used a cost of debt of 9.73%.

In determining the cost of debt, DBP used the Bank Bill Swap Rate as the reference rate, with cost of debt then being expressed as a total cost above BBSW. The total cost comprised a number of cost components, including the lender's margin and costs specific to particular markets.

9.2 Summary - BHPB Position

In BHPB's view, a cost of debt of 9.73% is inflated and unjustifiable. BHPB's submissions in respect of cost of debt are as follows:

(a) DBP should have determined the cost of debt using the well accepted basis of the nominal risk free rate plus a cost of debt margin instead of using an alternative approach; and

(b) the proposed cost of debt of 9.73% is too high in comparison to recent regulatory decisions.

BHPB submits that an appropriate value for cost of debt is not more than 8.75%.

9.3 DBP should have used the well accepted method

BHPB submits that DBP should have used the widely used and well accepted method of a nominal risk free rate plus a cost of debt margin instead of an alternative method. This is because the former method is the one principally used by Australian regulators.

In determining a rate of return Rule 87 of the NGR requires the use of a "well accepted approach".

A review of readily available Australian regulatory decisions reveals that a risk free rate plus a cost of debt margin is the principal approach used by Australian regulators in determining the cost of debt. This is demonstrated by the table below, which sets out a list of previous decisions, and the cost of debt approach used in them.

Year	Decision	Cost of debt model
2010	ERA - Goldfields Gas Pipeline (Final Decision)	Rf + cost of debt margin
2010	AER - NSW Gas Networks (Final Decision)	Rf + cost of debt margin
2010	AER - Wagga Wagga Natural Gas Distribution Network (Final Decision)	Rf + cost of debt margin
2010	AER - ACT, Queanbeyan and Palerang Gas Distribution Network (Final Decision)	Rf + cost of debt margin
2008	ACCC - Principal Transmission System (GasNet System) (Final Approval)	Rf + cost of debt margin
2008	ESC - Gas Access Arrangements (Envestra (Victoria), Multinet, SP AustNet, Envestra (Albury)) (Further Final Decision and Approval)	Rf + cost of debt margin
2007	ACCC - Dawson Valley Pipeline (Final Decision)	Rf + cost of debt margin
2006	ACCC - Roma to Brisbane Pipeline (Final Decision)	Rf + cost of debt margin
2006	QCA - Allgas Energy System (Final Decision)	Rf + cost of debt margin
2006	QCA - Envestra Limited Gas Distribution Pipeline (Final Decision)	Rf + cost of debt margin
2006	ESC - South Australian Gas Distribution System (Final Decision)	Rf + cost of debt margin
2005	ERA - Dampier to Bunbury Natural Gas Pipeline (Draft Decision approved in Final Decision)	Rf + cost of debt margin
2005	ERA - Goldfields Gas Pipeline (Final Decision)	Rf + cost of debt margin
2005	IPART - AGL Gas Networks (Final Decision)	Rf + cost of debt margin
2005	IPART - Country Energy Gas Network (Final Decision)	Rf + cost of debt margin
2005	ERA - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	Rf + cost of debt margin
2004	ICRC - ActewAGL Natural Gas System (Final Decision)	Rf + cost of debt margin

Year	Decision	Cost of debt model
2003	ACCC - Moomba to Sydney Pipeline (Final Approval)	Rf + cost of debt margin
2003	Australian Competition Tribunal - GasNet System (Tribunal Decision)	Rf + cost of debt margin
2002	ACCC - Amadeus Basin to Darwin Pipeline (Final Decision)	Rf + cost of debt margin
2001	ACCC - Moomba to Adelaide Pipeline System (Final Decision)	Rf + cost of debt margin
2001	QCA - Envestra Limited Gas Distribution (Final Decision Errata)	Rf + cost of debt margin
2001	QCA - Allgas Energy System (Final Decision Errata)	Rf + cost of debt margin
2000	ACCC - Central West Pipeline (Final Decision)	Rf + cost of debt margin
2000	ICRC - ActewAGL Natural Gas System (Final Decision)	Rf + cost of debt margin
2000	Offgar - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	CAPM (using debt beta)

In addition to this, regulators have stated that *"a benchmarking approach to estimating the cost of debt facing a service provider is preferable to estimating the service provider's actual cost of debt which may not reflect efficient financing sources."*[61] Using actual cost of debt figures has the potential to *"entrench higher debt costs"* and does not *"create incentives to seek the most efficient form of financing"* as it accepts the *"prevailing rate of debt even if it was not the most cost effective available"*.[62] The actual cost of debt facing the service provider should thus be abstracted from and the cost of debt should instead be *"determined through reference to a benchmark debt margin"*.[63]

Given this evidence, and the NGR's requirement that a "well accepted approach" be used, there is no reason or scope for DBP to depart from the use of a risk free rate plus a cost of debt margin in calculating the cost of debt for the DBNGP.

9.4 A cost of debt of 9.73% is too high compared to previous decisions

BHPB submits that not only is DBP's methodology not based on standard practice, but it has also produced a cost of debt that is too high compared to readily available Australian regulatory decisions, as set out in the table below.

[61] ACCC, April 2008, "Final Decision - Revised access arrangement by GasNet Australia (Operations) Pty Ltd and GasNet (NSW) Pty Ltd for the Principal Transmission System", page 68

[62] QCA, October 2001, "Final Decision - Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited", page 221

[63] ACCC, December 2002, "Final Decision - Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline", page 81

Year	Decision	Cost of debt (%)
2010	ERA - Goldfields Gas Pipeline (Final Decision)	8.75
2010	AER - NSW Gas Networks (Final Decision)	8.78
2010	AER - Wagga Wagga Natural Gas Distribution Network (Final Decision)	8.98
2010	AER - ACT, Queanbeyan and Palerang Gas Distribution Network (Final Decision)	8.98
2008	ACCC - Principal Transmission System (GasNet System) (Final Approval)	9.38
2008	ESC - Gas Access Arrangements (Envestra (Victoria), Multinet, SP AustNet, Envestra (Albury)) (Further Final Decision and Approval)	2.145*
2007	ACCC - Dawson Valley Pipeline (Final Decision)	7.15
2006	ACCC - Roma to Brisbane Pipeline (Final Decision)	6.94
2006	QCA - Allgas Energy System (Final Decision)	6.675
2006	QCA - Envestra Limited Gas Distribution Pipeline (Final Decision)	6.675
2006	ESC - South Australian Gas Distribution System (Final Decision)	7
2005	ERA - Dampier to Bunbury Natural Gas Pipeline (Draft Decision approved in Final Decision)	6.43-6.675
2005	ERA - Goldfields Gas Pipeline (Final Decision)	6.43-6.675
2005	IPART - AGL Gas Networks (Final Decision)	6.83-6.92
2005	IPART - Country Energy Gas Network (Final Decision)	6.5-6.6
2005	ERA - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	6.46-6.605
2004	ICRC - ActewAGL Natural Gas System (Final Decision)	6.66-6.84
2003	ACCC - Moomba to Sydney Pipeline (Final Approval)	6.26
2003	Australian Competition Tribunal - GasNet System (Tribunal Decision)	7.28
2002	ACCC - Amadeus Basin to Darwin Pipeline (Final Decision)	7.07

Year	Decision	Cost of debt (%)
2001	ACCC - Moomba to Adelaide Pipeline System (Final Decision)	6.81
2001	QCA - Envestra Limited Gas Distribution (Final Decision Errata)	7.51
2001	QCA - Allgas Energy System (Final Decision Errata)	7.51
2000	ACCC - Central West Pipeline (Final Decision)	7.58
2000	ICRC - ActewAGL Natural Gas System (Final Decision)	7.06-7.26
2000	Offgar - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	7.47

*debt margin above a risk free rate (real) of 3.36%

9.5 BHPB recommendation for cost of debt

BHPB submits that an appropriate value for cost of debt is not more than 8.75%.

10 Gamma

10.1 Issue

DBP assigned a value of zero to gamma in its estimation of the rate of return, making no allowance for the value of imputation credits.

10.2 Summary - BHPB Position

It is BHPB's view that a gamma value of 0 is incorrect. Recent regulatory decisions have not accepted a gamma of zero and furthermore, a nil value for gamma is inappropriate given the existence of Australian shareholding in the DBNGP.

BHPB submits that an appropriate value for gamma is 50-65%.

10.3 Previous regulatory decisions have not accepted a gamma of zero

Rule 87(2) of the NGR provides that in determining a rate of return on capital, it will be assumed that the service provider uses a *"financing structure that meets benchmark standards as to .. financial parameters for a going concern and reflects in other respects best practice."*

A nil value for gamma is not consistent with benchmark standards. This is demonstrated by readily available Australian regulatory decisions on the appropriate gamma, which have not accepted a gamma of zero, as shown in the table below. The AER electricity WACC review which decided on a gamma of 0.65[64] should also be noted.

[64] AER, May 2009, "Final Decision - Electricity transmission and distribution network service providers - Review of weighted average cost of capital (WACC) parameters", page v

Year	Decision	Gamma
2010	ERA - Goldfields Gas Pipeline (Final Decision)	0.37-0.81
2010	AER - NSW Gas Networks (Final Decision)	0.65
2010	AER - Wagga Wagga Natural Gas Distribution Network (Final Decision)	0.65
2010	AER - ACT, Queanbeyan and Palerang Gas Distribution Network (Final Decision)	0.65
2008	ACCC - Principal Transmission System (GasNet System) (Final Approval)	0.50
2008	ESC - Gas Access Arrangements (Envestra (Victoria), Multinet, SP AustNet, Envestra (Albury)) (Further Final Decision and Approval)	0.50
2007	ACCC - Dawson Valley Pipeline (Final Decision)	0.50
2006	ACCC - Roma to Brisbane Pipeline (Final Decision)	0.50
2006	QCA - Allgas Energy System (Final Decision)	0.50
2006	QCA - Envestra Limited Gas Distribution Pipeline (Final Decision)	0.50
2006	ESC - South Australian Gas Distribution System (Final Decision as amended by District Court of SA)	0.35-0.50
2005	ERA - Dampier to Bunbury Natural Gas Pipeline (Draft Decision approved in Final Decision)	0.30-0.60
2005	ERA - Goldfields Gas Pipeline (Final Decision)	0.30-0.60
2005	IPART - AGL Gas Networks (Final Decision)	0.30-0.50
2005	IPART - Country Energy Gas Network (Final Decision)	0.30
2005	ERA - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	0.30-0.60
2004	ICRC - ActewAGL Natural Gas System (Final Decision)	0.30-0.50
2003	ACCC - Moomba to Sydney Pipeline (Final Approval)	0.50
2003	Australian Competition Tribunal - GasNet System (Tribunal Decision)	0.50
2002	ACCC - Amadeus Basin to Darwin Pipeline (Final Decision)	0.50
2001	ACCC - Moomba to Adelaide Pipeline System (Final Decision)	0.50
2001	QCA - Envestra Limited Gas Distribution (Final Decision Errata)	0.50

Year	Decision	Gamma
2001	QCA - Allgas Energy System (Final Decision)	0.50
2000	ACCC - Central West Pipeline (Final Decision)	0.50
2000	ICRC - ActewAGL Natural Gas System (Final Decision)	0.30-0.50
2000	Offgar - Alinta Gas Distribution Systems (Mid West and South West Gas Distribution Systems) (Final Decision)	0.50

10.4 A gamma of zero is not appropriate given Australian shareholding

BHPB submits that it is not appropriate to make no allowance for the value of imputation credits given the existence of Australian shareholding in the owners of the DBNGP. The presence of Australian investors in the DBNGP means a gamma of 0 cannot stand. This is supported by DBP itself, in its initial proposed value for gamma of 0.20.[65]

10.5 BHPB recommendation for gamma

BHPB submits that an appropriate value for gamma is 50-65%.

11 Summary position

Based on the analysis provided above, BHPB submits that the WACC parameters applicable to the DBNGP are:

WACC parameters	DBP Proposed	DBP published for CAPM*	BHPB Submission
Market Risk Premium	Not used	6.50%	5-6%
Cost of debt	9.73%	9.73%	8.75%
Franking credit value (gamma)	0%	0%	50-65%

* parameters published in DBP Submission 8: Rate of Return to determine cost of equity with CAPM.

65 DBP, April 2010, "Submission 8: Rate of Return Public Version", page 25

PART C - REFERENCE SERVICE

12 Introduction

12.1 Issue

DBP is proposing to offer only one reference service, the “R1 Service”.

12.2 Summary - BHPB’s position

BHPB’s objections to the proposed reference service are that:

(a) the “R1 Service” is less reliable than the current “T1 Service” and for that reason is unlikely to be sought or utilised by a significant part of the market;

(b) part haul and back haul services have not been included as reference services, and these are likely to be sought by a significant part of the market; and

(c) spot capacity and inlet sales services have not been included as reference services, and these are likely to be sought by a significant part of the market.

On this basis, BHPB submits that the Proposed Access Arrangement should contain:

- a “T1 Service”, not an “R1 Service”;
- part haul and back haul services; and
- spot capacity and inlet sales services.

12.3 NGR requirements

Rule 101 of the NGR provides that:

“(1) A full access arrangement must specify all reference services.

(2) A reference service is a pipeline service that is likely to be sought by a significant part of the market.”

Rule 101 of the NGR thus requires all pipeline services that are likely to be sought by a significant part of the market to be reference services.

A pipeline service that is not likely to be sought by a significant part of the market cannot be a reference service.

13 “R1 Service”

13.1 Issue

DBP’s proposed reference service, the “R1 Service”, is less reliable than the current “T1 Service” as a result of ranking below the “T1 service” in the Curtailment Plan contained in schedule 6 of the Terms & Conditions and other amendments which are highlighted in Part D of this Submission.

13.2 BHPB Position

Given its lower reliability, the “R1 Service” is unlikely to be sought by a significant part of the market and therefore should not be a reference service.

A high percentage of pipeline users are currently on the "T1 Service" (or better). It is difficult to conceive that existing shippers would be willing to transfer from the T1 to the "R1 Service", as this would put them at a disadvantage and would be contrary to the interests of their financiers and investors. Nor does it appear that DBP expects significant demand for the "R1 Service" from prospective shippers, given DBP's assertion of limited growth in gas transmission".[66]

Contrary to DBP's submission that the Regulator cannot have regard to contracts that have already been entered into,[67] BHPB submits that pre-existing contracts are highly relevant as the desirability of a service will be determined by its relative attractiveness compared to the services available to shippers under pre-existing contracts. The relevance of existing contracts has been acknowledged by the Regulator in its 2005 Final Decision for the DBNGP. In this decision, the Regulator stated that it did not accept the contention that, in determining whether a service is likely to be sought by a significant part of the market, demand for the service should be considered only in the context of incremental demand during the access arrangement period.[68]

Further support for the proposition that the "R1 Service" is unlikely to be sought by a significant part of the market is provided by the fact that, as set out in the Issues Paper, on 1 January 2016, the tariff payable under contracts with the major shippers will revert to the nearest equivalent reference tariff under the access arrangement at that time. If DBP maintained its proposed "R1 Service" into the next Access Arrangement Period, it would result in two services of different reliability levels with the same price. This is clearly an untenable situation which, BHPB contends, would eliminate demand for the inferior "R1 Service".

In addition to this, BHPB supports the Regulator's view that the historical willingness of users and DBP to enter into contracts for a particular service indicates that that service is likely to be sought by a significant part of the market.[69] Therefore, the fact that shippers have consistently negotiated with DBP for the provision of the "T1 Service" as the "firm service" on the DBNGP indicates that it is this service that is likely to be sought by the market, and not a lower priority "firm service".

BHPB's submission supports the Regulator's 2005 Final Decision for the DBNGP. In this decision, the Regulator decided that DBP's proposed reference service, the "Tf service", was not one which would likely be sought by a significant part of the market. One of the main reasons for the Regulator's decision was the subordinate priority of the "Tf Service", relative to other services, for gas receipts and deliveries in the event that a curtailment or interruption was necessary. BHPB submits that there is no valid reason for the Regulator to depart from this earlier position.

DBP also submits that in assessing whether a service is likely to be sought, the ERA must have regard to whether there is spare uncontracted capacity on the DBNGP or if there is not, whether there is a likelihood that the capacity of the pipeline will be expanded during the Access Arrangement Period.[70] This directly conflicts with the Regulator's 2005 Final Decision for the DBNGP, in which it stated that it does not accept that a lack of spare capacity on a pipeline to provide a service of a particular nature necessarily entails that the service is not likely to be sought by a significant part of the market.[71]

66 ERA, May 2010, "Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement Issues Paper", page 16

67 DBP, April 2010, "Submission 3: Pipeline Services Public Version", page 5

68 ERA, November 2005, "Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline", page 29

69 ERA, November 2005, "Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline", page 16

70 DBP, April 2010, "Submission 3: Pipeline Services Public Version", page 5

71 ERA, November 2005, "Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline", page 19

14 Part haul and back haul services

14.1 Issue

DBP have not included part haul and back haul services as reference services.

14.2 BHPB Position

BHPB submits that part haul and back haul services should be reference services as they are likely to be sought by a significant part of the market.

In the Regulator's 2005 Final Decision for the DBNGP, the Regulator required that part haul and back haul services be included as reference services. In relation to part haul services, the Regulator indicated that there is a substantial interest of users and prospective users in having a part haul service as a reference service, and a substantial public interest in the potential for a part haul service as a reference service to facilitate the supply of competitively priced gas to end users in the Pilbara and Mid-West regions of the State, and to end users of gas in the South West region via the Parmelia Pipeline.[72]

BHPB submits that there is no valid reason for the Regulator to depart from its earlier findings that a part haul and back haul service would be sought by a significant part of the market. Indeed, the demand for these services will likely only increase as new gas sources come on-line which are located south of I1-01 and also as demand for gas increases in the North West for mining.

BHPB further submits that in determining the terms and conditions of a reference back haul service, the minimum term condition should be fundamentally different from that applicable to the "T1 Service". A minimum term of 15 years for a back haul service is entirely inappropriate as there is no capital expansion required. The minimum term of a back haul service should be nominated by the shipper.

15 Spot Capacity and Inlet Sales Services

15.1 Issue

DBP have not included spot capacity and inlet sales services as reference services.

15.2 BHPB Position

BHPB submits that spot capacity and inlet sales services should be reference services as they are likely to be sought by a significant part of the market and there is no real incremental cost of providing these services to DBP.

[72] ERA, November 2005, "Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline", page 28

PART E - Terms and Conditions

16 Introduction

16.1 Issue

DBP has proposed substantial changes to the Terms and Conditions in the current Access Arrangement (**Terms & Conditions**).

16.2 Summary - BHPB Position

BHPB submits that the information DBP has provided in relation to its proposed changes to the Terms & Conditions is wholly inadequate. It is BHPB's view that any changes that do not have sufficient supporting information should not be approved by the Regulator, at least until such time as DBP provides this information and stakeholders have had an opportunity to consider this information and make submissions to the Regulator.

In addition to the submission relating to the lack of information, BHPB submits that several of the proposed amendments to the Terms & Conditions should not be approved for a number of reasons, including that they are contrary to the national gas objective and NGL.

Given BHPB's submissions in relation to the inappropriateness of the "R1 Service" in 13 above, BHPB does not propose to make comments in relation to all of the proposed amendments which DBP suggests are consequential on the "R1 Service" (see 2.6(c) of DBP's Submission 5). As these amendments are, by DBP's own admission, only made because they go towards defining the "R1 Service" as a service that is different to the "T1 Service", BHPB submits that they should be rejected along with the "R1 Service".

17 Inadequate information in support of changes

17.1 Issue

DBP's access arrangement information contains minimal information to justify the changes it has proposed to the Terms & Conditions.

17.2 BHPB Position

BHPB submits that the information provided by DBP (or lack thereof) in respect of a number of changes to the Terms & Conditions does not comply with the requirements of the NGR.

Rule 43 of the NGR provides that:

> *"(1) A service provider, when submitting an access arrangement proposal … must submit, together with the proposal, access arrangement information for the access arrangement proposal."*

The required scope of this access arrangement information is set out in Rule 42:

> *"(1) Access arrangement information for an access arrangement or an access arrangement proposal is information that is reasonably necessary for users and prospective users:*
>
> *(a) to understand the background to the access arrangement or the access arrangement proposal; and*
>
> *(b) to understand the basis and derivation of the various elements of the access arrangement or the access arrangement proposal."*

On the majority of changes to the Terms & Conditions, the information DBP has provided is limited to a cross in a table, simplistically categorising the change into one of four categories. This information can in no way be said to be sufficient to allow users to understand the basis and derivation of the elements of the access arrangement. In other words, the information (or lack thereof), clearly does not meet the requirements of Rule 42 of the NGR.

On this basis, BHPB submits that any of the changes to the Terms & Conditions that do not have sufficient supporting information (which BHPB submits is all substantive amendments) should not be approved by the Regulator until such time as DBP is able to provide sufficient information in support of the relevant change and stakeholders have had an opportunity to consider this information and make submissions to the Regulator. Subsequent to the provision of this information, BHPB submits that there should be a period of consultation available for shippers to comment on the changes.

18 Terms and Conditions

18.1 Issue

DBP has proposed substantial changes to the Terms & Conditions, including changes that significantly amend the rights and obligations of the operator and shippers.

18.2 Summary - BHPB Position

In relation to the changes set out in 18.4 to 18.17 below, BHPB reiterates its submission made in 17 above, that the changes should not be approved without sufficient information in support. BHPB also makes additional objections to the changes as set out below.

18.3 NGR and NGL Requirements

Rule 100 of the NGR requires the provisions of an access arrangement to be consistent with the national gas objective.

The national gas objective is contained in section 23 of the NGL, which provides that:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas"*

It is clear that the national gas objective puts a strong emphasis on efficiency but also a requirement that this is for the long term interests of consumers.

18.4 Restrictions on Secondary Gas Market

(a) *Issue*

A number of changes to the Terms & Conditions restrict competition by inhibiting various secondary gas markets related to the DBNGP.

(b) *BHPB Position*

BHPB submits that restricting competition in the form of secondary markets is contrary to the national gas objective, as well as the *Trade Practices Act 1974 (Cth)* and NGL generally. Therefore, in order to ensure compliance with the legislative requirements, the following changes to the Terms & Conditions, which have the potential to remove or restrict competition, should be rejected by the Regulator.

(i) Changes to the Imbalance Regime

DBP has proposed various changes to the Imbalance Regime, including changes to limits and timing. These changes will make it harder for shippers to trade their daily imbalances. Historically, all shippers have had the flexibility of trading their daily imbalances to reduce their exposure to imbalance charges. If some shippers are on different Terms & Conditions, the ease of trade will be adversely affected.

(ii) Changes to Capacity

DBP's proposed changes to the Terms & Conditions remove the ability of shippers with full haul capacity to utilise this for the purposes of part haul which in turn prevents a shipper trading, or delivering gas to anyone, upstream of CS9 (see the deletion of clause 8.18). BHPB submits that whilst the use of full haul capacity in this way is not a common occurrence, the change prevents competition, giving DBP an effective monopoly on the provision of part haul services. BHPB submits that this issue is further exacerbated by DBP's proposal that there is no part haul reference service.

BHPB also submit that shippers should be permitted to use forward haul capacity for the purposes of back haul.

In addition to this, the overall changes to the Terms & Conditions in relation to capacity will significantly hinder shippers on the new access arrangement Terms & Conditions from trading with existing shippers as it will result in the two groups of shippers being on different contractual arrangements.

These restrictions on the flexibility of shippers to trade their capacity are clearly inconsistent with the objective of efficiency and so should be rejected.

(iii) Removal of the Spot Capacity Market.

DBP has proposed the deletion of clause 3.5 of the Terms & Conditions. Clause 3.5 provides the process by which shippers can bid for and obtain Spot Capacity under the Access Arrangement. The removal of this clause could ultimately reduce the ability to trade excess gas. Shippers, who may not have existing access to the spot market, may suffer long lead times in arranging a contract to access Spot Capacity and therefore miss out on potential sales or purchases. The removal of the provisions relating to spot capacity therefore reduces the effectiveness of a spot gas market and should not be approved.

In addition to this, it is a convenience to existing shippers to be able to access Spot Capacity without having to pursue separate terms and conditions with DBP.

(iv) Requirement for an inlet sales agreement

In clause 25.6, DBP proposes to impose a new requirement on shippers wishing to utilise other shippers' daily nominations to enter into an Inlet Sales Agreement before they can do so. BHPB submits that this amendment is unjustifiable, particularly where DBP retains the flexibility to determine the terms of that arrangement from time to time. This reduces competition and efficiency as it could be used to effectively prevent the utilisation of capacity for third parties.

The changes in clause 25.6 should therefore not be approved.

18.5 Notice for Option to Renew Contract

(a) *Issue*

DBP also proposes to amend clause 4.5 of the Terms & Conditions so that shippers must give written notice to the Operator 30 months in advance of exercising an Option, compared to the current notice period of 3 months.

(b) *BHPB Position*

BHPB submits that a requirement that the shipper give 30 months notice prior to extending the term of its contract is unreasonable, as most shippers will not be in a position to make informed decisions as to their transportation needs 30 months in advance. BHPB submits that the position in the current Terms & Conditions should be amended to provide a longer notice period, but that the relevant notice period be limited to 12 months.

18.6 System Use Gas

(a) *Issue*

Clause 5.10 provides that the Operator must supply the shipper's share of System Use Gas.

(b) *BHPB Position*

BHPB submits that clause 5.10 should be amended to entitle, but not oblige, shippers to supply their own System Use Gas.

The basis of this submission is that allowing shippers to supply their own System Use Gas is the most efficient option, as the party who is in the best position to supply the System Use Gas will ultimately end up doing so. DBP's proposal that the Operator supply the shipper's share of System Use Gas should therefore be rejected on the basis that it does not promote efficiency and is therefore inconsistent with the national gas objective and Rule 100 of the NGR.

18.7 Accumulated Imbalance (clause 9)

(a) *Issue*

DBP proposes removing a number of protections previously enjoyed by shippers in the accumulated imbalance regime (clause 9) including:

(i) the requirement for a material adverse impact before DBP is able refuse to receive or deliver gas or issue a notice requiring a shipper to reduce its imbalance;

(ii) the concept of deemed best endeavours on the part of the shipper;

(iii) the prohibition on DBP issuing a notice or refusing to receive or deliver gas unless it has first, to the extent reasonable, endeavoured to co-operate with the shipper to ameliorate the impact of the shipper's accumulated imbalance;

(iv) the prohibition which applies in most instances on DBP refusing to receive or deliver gas without having issued a notice (unless due to force majeure or emergency); and

(v) the exemption from paying an excess imbalance charge if the imbalance arose because the shipper's capacity service was curtailed.

(b) *BHPB Position*

BHPB submits that these protections should be reinstated as there is no justification for removing them. The proposed changes go beyond those required to accommodate changed legislative requirements and would not be accepted in a competitive market. Therefore, contrary to the national gas objective, the changes do not promote efficient operation and use of natural gas services for the long term interests of consumers and so should be rejected.

18.8 Deletion of the Outer Hourly Peaking Limit (clause 10.4)

(a) *Issue*

DBP proposes removing the following protections from the peaking regime (clause 10):

(i) the requirement for a material adverse impact before DBP is able refuse to deliver gas or issue a notice requiring a shipper to reduce its take of gas;

(ii) the concept of deemed best endeavours on the part of the shipper; and

(iii) the permissible peaking excursion in clause 10.7.

(b) *BHPB Position*

BHPB submits that these protections should be reinstated as there is no justification for removing them. The proposed changes go beyond those required to accommodate changed legislative requirements and would not be accepted in a competitive market. Therefore, contrary to the national gas objective, the changes do not promote efficient operation and use of natural gas services for the long term interests of consumers and so should be rejected.

18.9 Overrun Rate

(a) *Issue*

DBP has amended the Overrun Rate in clause 11.1(b) of the Terms & Conditions to be the greater of :

(i) 500% of the R1 Tariff; and

(ii) the highest price bid for Spot Capacity which was accepted for that Gas Day other than when the highest price bid was not a bona fide bid, in which case the highest bona fide bid.

Under the current Terms & Conditions the Overrun Rate is the greater of (ii) above and 115% of the T1 Reference Tariff.

(b) *BHPB Position*

BHPB submits that there is no basis for the Overrun Rate to be amended and on this basis the Regulator should reject DBP's amendment to clause 11.1(b) of the Terms & Conditions.

The proposed changes go beyond those required to accommodate changed legislative requirements and result in a much higher Overrun Rate than would be negotiated in a competitive market. The changes therefore do not promote the efficient operation and use of natural gas services for the long term interests of consumers and as such are contrary to the national gas objective and should be rejected.

18.10 Return of Other Charges (Clause 20.4)

(a) *Issue*

The Operator is not required to return “Other Charges” levied in excess of the cost the Operator incurs as a result of the conduct entitling such charge to be levied.

(b) *BHPB Position*

BHPB submits that the Operator should only be able to retain an amount of revenue from the Other Charges equal to the costs the Operator incurs as a result of the conduct entitling such charge to be levied. The remainder of the revenue from the Other Charges should be redistributed to the non-offending shippers. If this is not done, the Operator will make a profit over and above the regulated return. Allowing the Operator to do so is contrary to the national gas objective.

BHPB’s submission is consistent with the Regulator’s recent decision on the GGP, in which the Regulator noted that it was not reasonable for GGT to delete the rebate mechanism and thereby retain all of the Quantity Variation Charges if this revenue was not taken into account when determining the Reference Tariff.[73]

18.11 Assignment of Capacity (Clause 25.3)

(a) *Issue*

DBP has made a number of amendments to clause 25. The broad effect of these amendments is as follows:

(i) DBP has made it harder for shippers to grant security by requiring the tripartite deed to be in a form which is published on the Operator’s website from time to time (rather than a form approved by the Regulator in the Terms & Conditions), therefore giving the Operator unilateral discretion as to the terms of this deed;

(ii) DBP has increased the difficulty of assignment by shippers to related bodies corporate by requiring the proposed assignee to provide security under clause 25.3(a)(iii), even though in that instance the original shipper is not released from liability;

(iii) DBP has changed the previously reciprocal nature of clause 25.3 by now allowing the Operator to be released from future liability (but not the shipper);

(iv) DBP has removed the shipper’s ability to withhold consent to an assignment by the Operator on the basis that the proposed assignee does not have financial capability and technical expertise; and

(v) DBP has inserted additional conditions on assignment by the shipper in 25.4(b).

(b) *BHPB Position*

In relation to all of the above, BHPB submits that these changes are unreasonable and go beyond those required to accommodate changed legislative requirements. The changes

[73] ERA, October 2009, “Draft Decision on GGT’s Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline”, page 169 (approved in Final Decision)

would not be accepted in a competitive market and are therefore contrary to the national gas objective as they do not promote efficiency. The changes should therefore not be approved by the Regulator.

In relation to (v) specifically, BHPB submits that the addition of 25.4(b) is inappropriate from a drafting perspective as it is unclear how it interacts with 25.3(c) given that they both appear to cover the same ground in relation to the Operator's ability to withhold consent.

18.12 Removal of General Right of Relinquishment

(a) *Issue*

DBP have deleted the general right of relinquishment available to shippers under clause 26 of the Terms & Conditions.

(b) *BHPB Position*

BHPB disputes the removal of the general right of relinquishment contained in clause 26 of the current Terms & Conditions as there is no justification to remove this right of the shippers.

The proposed changes go beyond those required to accommodate changed legislative requirements and would not be accepted in a competitive market. The changes may impact the ability to effectively utilise unutilised capacity and therefore reduce efficiency. Therefore, contrary to the national gas objective, the changes do not promote efficient operation and use of natural gas services for the long term interests of consumers and so should be rejected.

18.13 Permitted Disclosures

(a) *Issue*

Under clause 28.3 of the Terms & Conditions, either party may disclose Confidential Information to its Related Bodies Corporate which, for the purposes of the Operator, expressly includes Alcoa of Australia Limited (**Alcoa**). Alcoa is currently a shipper on the DBNGP.

(b) *BHPB Position*

BHPB submits that the Operator should be prohibited from disclosing Confidential Information to a third party shipper who is also an owner on the basis that it is anti-competitive and contrary to the national gas objective focus of efficiency.

18.14 Environmental Warranty

(a) *Issue*

DBP has deleted the warranty given by the Operator in clause 30.1(a)(i) of the Terms & Conditions in which the Operator warrants that it has complied with and will during the Contract term continue to comply with, all Environmental and Safety Laws with respect to any of its obligations connected with, arising out of or in relation to the Contract.

(b) *BHPB Position*

BHPB submits that the Regulator should reject the deletion of the warranty given by DBP in clause 30.1(a)(i) of the Terms & Conditions on the basis that it is clearly contrary to the national gas objective which refers to the efficient operation and use of natural gas services with respect to price, quality, safety, reliability and security of supply.

18.15 Shipper Request for Information from Operator

(a) *Issue*

DBP have proposed the deletion of clause 31(b), which allows a shipper to request from the Operator a non-binding indicative summary of its material planned expansions of the Gas Transmission Capacity for the following 5 years.

(b) *BHPB Position*

BHPB submits that the Regulator should reject the deletion of clause 31(b) on the ground that the information is necessary for the efficient investment in and efficient operation and use of natural gas services as it allows shippers some scope to plan their own future gas consumption, operations and expansions.

18.16 Deletion of Non-discrimination Clause

(a) *Issue*

DBP have proposed the deletion of clause 45 of the Terms & Conditions which, in summary, requires the Operator to:

(i) provide all shippers with information related to maintenance, Spot Capacity, Curtailment and DBNGP flow data at substantially the same time;

(ii) treat all shippers on an arms' length basis; and

(iii) ensure that no shipper which is an Associate of a Relevant Company receives a benefit, unless the benefit is attributable to an arms' length application of the two shippers' respective contractual entitlements entered into on terms and conditions comparable with the Standard Shipper Contract.

(b) *BHPB Position*

BHPB submits that the Regulator should refuse DBP's proposed deletion of clause 45 of the Terms & Conditions. The clause is clearly required to ensure that the national gas objective and concepts of fair competition are met given that key shippers on the DBNGP are related to the DBNGP owners.

18.17 Efficiency-incentive Mechanism

(a) *Issue*

The Proposed Access Arrangement does not contain any incentive or obligation for DBP to operate the DBNGP as efficiently as possible.

(b) *Summary - BHPB Position*

BHPB submits that the Access Arrangement should contain an incentive mechanism which seeks to ensure that the DBNGP is run as efficiently as possible, consistent with the national gas objective. This is particularly important given the proposed pass through of carbon taxes.

(c) *NGL and NGR requirements*

The national gas objective states that the objective of the NGL is to "*promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas"*. Rule 100 of the NGR requires the provisions of an access arrangement to be consistent with this national gas objective.

This focus on economic efficiency is reinforced in the revenue and pricing principles in section 24 of the NGL. Most relevantly, the second principle states that "*a service provider should be provided with effective incentives in order to promote economic efficiency"*. The economic efficiency that should be promoted includes efficient investment in and provision and use of pipeline services.

Under Rule 98 of the NGR, the ERA may require a full access arrangement to include one or more incentive mechanisms to encourage efficiency in the provision of services. The incentive mechanism must be consistent with the revenue and pricing principles.

(d) *Proposed incentive mechanism*

BHPB submits that in order to comply with the national gas objective and its focus on economic efficiency, the Regulator must ensure that DBP is motivated under the terms of the Access Arrangement to minimise gas consumption and gas losses in its operations and therefore associated emissions. This is not only consistent with the national objective but also with market practice in a competitive market where there is any attempt to pass the risk of future carbon costs to consumers.

An example of an incentive mechanism in relation to System Use Gas is as follows:

(i) an independent specialist consultant be engaged to establish the efficient level of System Use Gas for the DBNGP. This may include a narrow range of acceptable operation; and

(ii) System Use Gas limits are then set through the Access Arrangement; and

(iii) where DBP operates the DBNGP more efficiently than the set guidelines, it is entitled to retain the revenue derived from the gas saving (or incremental System Use Gas provided by shippers); and

(iv) where DBP operates the DBNGP less efficiently that the set guidelines, it is required to provide the incremental System Use Gas above the set limits without an entitlement to pass this cost to shippers.

PART E - OTHER ISSUES

19 Capital expenditure

19.1 Issue

DBP is seeking a total capital expenditure of $1.8bn to be added to the capital base in respect of the previous Access Arrangement Period.

DBP's forecasts of capital expenditure total $137 million during the next access arrangement period, of which $133 million is stated as being conforming capital expenditure. DBP has indicated that during the next Access Arrangement Period:

- it expects limited growth in gas transmission on the DBNGP due to gas price increases, an emerging carbon price, and a generally stagnant gas market;
- there will be no expansion of the DBNGP; and
- forecast conforming capital expenditure is broadly related to maintenance, safety and reliability and meeting regulatory obligations.

19.2 BHPB Position

BHPB submits that the Regulator examine DBP's capital expenditure figures closely to ensure that they comply with the NGR requirements. However, on the basis of the limited Revised Access Arrangement Information on this point, BHPB is not in a position to make substantive submissions.

20 Operating expenditure

20.1 Issue

DBP proposes total forecast operating expenditure for 2011-2015 of $584.3k.

20.2 BHPB Position

BHPB submits that the Regulator examine DBP's operating expenditure figures closely to ensure that they comply with the NGR requirements. However, on the basis of the limited Revised Access Arrangement Information on this point, BHPB is not in a position to make substantive submissions.

21 Reference Tariff Variation Mechanism

21.1 Issue

DBP's proposed reference tariff variation mechanism, and in particular the New Costs Pass Through Variation, allows the pass through of potentially a very wide variety of additional costs.

The New Costs Pass Through Variation broadly allows DBP to recover expenses it or its related bodies corporate incur which are beyond its control, which could not be predicted prior to the approval of the Proposed Access Arrangement and which were not included in total revenue.

21.2 BHPB Position

Through the introduction of the New Cost Pass Through Variation, DBP's proposed reference tariff variation mechanism is significantly expanded in scope from the current access arrangement. BHPB submits that this expanded scope should not be approved as it is inconsistent with Rule 97 of the NGR, the national gas objective and revenue and pricing principles.

(a) *The New Cost Pass Through Variation is inconsistent with Rule 97 of the NGR*

Rule 97(1) of the NGR sets out specific ways in which a reference tariff variation mechanism may provide for variation of a reference tariff. These are: in accordance with a schedule of fixed tariffs, in accordance with a formula set out in the access arrangement, as a result of a cost pass through for a defined event or by the combined operation of two or more of these.

BHPB submits that the New Cost Pass Through Variation cannot be said to fall into any of these categories. The expenses which the mechanism allows the DBP to pass through are not for a "defined event", rather they are sufficiently broad as to capture effective **any** event.

(b) *The New Cost Pass Through Variation is inconsistent with the national gas objective*

Section 23 of the NGL states that the objective of the NGL is to *"promote efficient investment in, and efficient operation and use of, natural gas services"*. This focus on economic efficiency is reinforced in the revenue and pricing principles in section 24 of the NGL. Most relevantly, the second principle states that a service provider should be provided with effective incentives in order to promote the economically efficient investment in and provision and use of pipeline services. Rule 100 of the NGR requires the provisions of an access arrangement to be consistent with the national gas objective.

DBP's proposed New Cost Pass Through Variation allows the pass through of potentially a very wide variety of costs. Increasing the scope of costs DBP is able to pass through significantly reduces the incentives to DBP to operate efficiently and thus is contrary to the NGL. The inefficiency and inequality of DBP's proposal is clearly highlighted by the fact that the variation only operates one way. Any cost reductions are not passed through.

In addition, a variation mechanism of the kind and scope proposed by DBP cuts across the ongoing requirement of the Regulator to be satisfied that expenditure is properly incurred. BHPB submits that the variation mechanism be limited to the variation mechanism in the current Terms & Conditions, with only changes in costs attributable to Tax Changes being passed through. In respect of any other cost changes, these should then be managed through revision to the Access Arrangement in the next Access Arrangement Period.